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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EA-2017-0345

DIRECT TESTIMONY

OF

TODD SCHATZKI, Ph. D.

ON

BEHALF OF

AMEREN TRANSMISSION COMPANY OF ILLINOIS

Boston, Massachusetts
September, 2017

TABLE OF CONTENTS

DIRECT TESTIMONY

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I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name, business address and present position.

A. My name is Todd Schatzki. I am employed by Analysis Group, Inc. ("Analysis Group"), where I am a Vice President in the Boston office. Analysis Group is a firm that provides microeconomic, strategy and financial analyses. My business address is 111 Huntington Avenue, 14th Floor, Boston, MA 02199. Analysis Group has approximately 800 professionals and offices in Beijing, Boston, Brussels, Chicago, Dallas, Denver, London, Los Angeles, Menlo Park, Montreal, New York City, San Francisco and Washington, D.C.

Q. Please summarize your professional experience and educational background.

A. I received a Bachelor of Arts in physics from Wesleyan University, a Masters in City Planning, Environmental Policy and Planning from the Massachusetts Institute of Technology and a Ph.D. in Public Policy from Harvard University. Since receiving my doctorate degree, I have worked with several economic consulting firms, including National Economic Research Associates, Inc., LECG, LLC and now Analysis Group. My professional experience and qualifications are summarized in my curriculum vitae, which is included as **Schedule TS-01**.

For nearly twenty years, I have worked on energy sector economics, regulation, and policy, including work for government agencies, regulators, market operators, non-profit organizations, and private corporations. This work has included: market design; economic and financial analysis of energy and environmental regulations and infrastructure changes;

ratemaking design and analysis; design and assessment of environmental regulations affecting the electric power sector; and assessment of market competition and manipulation. My work has appeared in both academic and industry journals such as the *Journal of Environmental Economics and Management*, *the Electricity Journal*, and *Public Utilities Fortnightly*, and in publications associated with institutions such as the AEI-Brooking Joint Center for Regulatory Studies and the Harvard Regulatory Policy Program.

In recent years, much of my work has involved wholesale power markets in a number of regions of the U.S. I have helped in the review and redesign of market rules, performed economic analysis of the impacts of proposed market rules, evaluated resource performance under existing market designs and assessed economic damages associated with disputes regarding wholesale power contracts. I have worked for market operators in New England ("ISO-New England") and New York ("NYISO") on a variety of issues related to market design, market monitoring and the analysis of the impact of market rule changes under consideration. My work has involved issues in many organized wholesale markets, including California ISO, ISO-New England, Midcontinent Independent System Operator, Inc. ("MISO"), NYISO, PJM and the Southwest Power Pool ("SPP"). I have utilized production cost models on numerous occasions to evaluate the impacts of new regulations and changes in generation and transmission infrastructure. This work has included multiple confidential assignments and analysis of transmission projects in the MISO footprint. I have submitted testimony to both federal and state regulatory commissions, including the Missouri Public Service Commission ("Commission") in an earlier proceeding involving the project under consideration in this case.

Q. On whose behalf are you testifying in the current proceeding?

A. I am testifying on behalf of Ameren Transmission Company of Illinois ("ATXI") in support of its request for a Certificate of Public Convenience and Necessity ("CCN") for a transmission line project in northeast Missouri. As noted, I submitted testimony on ATXI's behalf in an earlier CCN case involving the same project (File No. EA-2015-0146).

Q. Are you familiar with the project proposed by ATXI?

A. Yes. ATXI is seeking a CCN for the "Mark Twain Transmission Project", which I will refer to it as the "Project". This is the same project that was the subject of the earlier case, except that the Project will now be constructed along a somewhat different route. While the route has been adjusted, the basics of the Project remain the same, with the same electrical connections and electrical design as the earlier project, which was approved with conditions by the Commission in April, 2016. More specifically, ATXI seeks a CCN authorizing it to construct, operate and maintain a 345-kV electric transmission line, approximately 96 miles in length, and related facilities. These facilities are part of a portfolio of Multi-Value Projects ("MVP"), which were approved by MISO's Board of Directors in December 2011.

II. PURPOSE, SCOPE AND SUMMARY OF CONCLUSIONS

Q. What is the purpose of your testimony?

A. I understand that this Commission has generally evaluated an application for a CCN under the five so-called *Tartan* factors,[1] which include:

1. Whether there is a need for the facilities and service;

[1] These factors were outlined in *In Re Tartan Energy*, GA-94-127, 3 Mo. P.S.C.3d 173, 177 (1994).

2. Whether the applicant is qualified to own, operate, control and manage the facilities and provide the service;

3. Whether the applicant has the financial ability for the undertaking;

4. Whether the proposal is economically feasible; and

5. Whether the facilities and service promote the public interest.

My testimony provides economic analysis relevant to the first, fourth and fifth of these criteria – that is, whether there is a need for the facilities and services, whether the project is economically feasible, and whether the project is in the public interest.

Q. Are you sponsoring any schedules in support of your direct testimony?

A. Yes. I am sponsoring **Schedule TS-01** (curriculum vitae), **Schedule TS-02** (Technical Appendix), and **Schedule TS-03** (Tables of Results).

Q. Please summarize your conclusions.

A. My analyses support the conclusion that the Project meets the Tartan criteria related to need, economic feasibility, and public interest. The Project would be expected to provide the state of Missouri with many positive economic benefits, thus demonstrating that the Project is in the public interest. Among these benefits, the Project would enable the delivery of additional wind generation to support the achievement of Missouri renewable energy portfolio requirements and other state energy initiatives, while also improving reliability, thus demonstrating a need for the Project. In addition, the Project was developed under a MISO planning process through which it was demonstrated that the MVP Portfolio, of which the Project is a part, provides positive benefits as compared to its costs. My analysis confirms that the Project itself (as compared to the Portfolio overall) also provides significant positive benefits in excess of its costs. Consequently, the Project is economically feasible.[2]

The Project's development would be expected to lower the overall social cost to Missouri from providing electricity service to Missouri customers. Reductions in social cost would reflect both the reduction in the costs of producing electricity to meet Missouri customer loads, and reduced environmental impacts to Missouri residents from producing electricity, in the form of lower emissions of carbon dioxide ("CO_2") generated throughout the MISO footprint, as well as lower emissions of nitrogen oxides ("NO_X"), sulfur dioxide ("SO_2") and mercury from sources within Missouri.

The Project's development would also be expected to lower expenditures by Missouri businesses and residents on electricity. These reductions in payments for electric energy service would likely far outweigh the impact of transmission charges to Missouri load-serving entities (primarily Ameren Missouri) from the Project. Thus, on net, the Project would be expected to reduce customer payments.

The Project would also be expected to lower wholesale energy prices, which is consistent with lower social costs, lower customer payments, and improved market efficiency. In total, these impacts would provide substantial benefits to Missouri, as well as to the MISO North[3] region as a whole.

[2] As the Commission's Staff indicated in the earlier CCN case, the economic feasibility of the Project is also supported by the fact that FERC has approved the recovery of the Project's costs through rates in the MISO tariff to be paid by market participants throughout MISO's Northern Region. Approximately 8 percent share of transmission charges arising from the Project would be paid by customers of Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri") and the City of Columbia municipal utility.

[3] As discussed later in my testimony, results of my analysis for MISO's footprint are for the MISO footprint prior to Entergy's entry into MISO in December 2013 (an area generally referred to as "MISO North"). My analysis develops metrics for MISO North because, among other things, the MVP Portfolio was designed to provide benefits to MISO North.

Q. How is your testimony organized?

A. In Section III of my testimony, I provide a description of the proposed facilities. In Section IV, I describe the approach used to evaluate the Project's economic impact. Finally, in Section V, I report the results of my analysis.

III. DESCRIPTION OF THE PROPOSED TRANSMISSION FACILITIES

Q. What is your understanding of the proposed facilities?

A. The Project is described more completely in the direct testimony of ATXI witness James (Jim) Jontry. I understand that the Project includes transmission facilities that will be routed south from the Missouri-Iowa border to the proposed ATXI Zachary Substation near Kirksville, Missouri, and then westerly on to the Maywood switching station near Palmyra, Missouri. I also understand that the Project would include approximately 96 miles of new 345-kV transmission line, a new 345-kV terminal and 345/161 kV step-down transformer at the new Zachary Substation, which will be electrically connected to an existing 161-kV substation owned by Ameren Missouri and located immediately adjacent to the Zachary Substation site.

Q. What is your understanding of the total cost of the proposed facilities?

A. As indicated in Mr. Jontry's direct testimony, the Project is expected to go into service in December 2019 with an expected nominal cost of $250.3 million. These costs would primarily be incurred in 2017 to 2020.

Q. What is your understanding of the principal benefits to the regional electric system that will be provided by the Project?

A. As discussed in direct testimony being submitted by ATXI witness Dennis Kramer, the Project would provide a wide range of benefits, including mitigation of potential reliability concerns, reduced congestion and improved integration of distant generation resources (as well as not-as-distant resources, such as wind zones in Missouri) within the MISO North footprint. These benefits were also identified in the MISO planning process that developed the Project as an element of the MVP Portfolio.

Q. What is the MVP Portfolio?

A. The MVP Portfolio is a package of transmission projects that allows for a more efficient dispatch of generation resources, opening markets to further competition and spreading the benefits of low-cost generation. Through a MISO planning process, MVPs have been "determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones."[4] The Federal Energy Regulatory Commission approved the MVP methodology because it "is an important step in facilitating investment in new transmission facilities to integrate large amounts of location-constrained resources, including renewable generation resources, to further support documented energy policy mandates or laws, reduce congestion, and accommodate new or

[4] Midwest Independent Transmission System Operator, Inc. ("MISO"), 133 FERC ¶ 61,221 at Para 1 ("Dec. 16, 2010 Order"). See also the listing of the three MVP criteria in Section II.C.2 of Attachment FF of the MISO Tariff, as follows:

> Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.
>
> Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher ….
>
> Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs ….

growing loads."[5] MISO performed a comprehensive assessment of the portfolio of 17 MVPs, referred to as the MVP Report.[6] The findings of this assessment supported the recommendation that each of the 17 projects be approved by MISO's Board of Directors for inclusion in Appendix A of the MISO Transmission Expansion Planning process and implemented. On December 8, 2011, the MISO Board of Directors approved this recommendation.

Q. Is the Project a Multi-Value Project?

A. Yes, the Project consists of nearly all of MVP 8 and the Missouri portion of MVP 7, and is an integral part of the overall MVP Portfolio, which includes transmission projects throughout the northern portion of the MISO footprint.[7] My analysis of the Project considers the impact of both MVP 7 and 8, in their entirety. This assumption is reasonable because the transmission line from the Zachary Substation to Ottumwa, Iowa, as currently designed, does not interconnect with any other transmission facilities between these two points. Consequently, there would be no reason to construct the Iowa portion of MVP 7 without the Missouri portion of MVP 7, because the line would not connect to any nodes in the transmission system and thus could not flow power.

Q. Did the selection of the MVP Portfolio projects reflect consideration of any economic criteria?

A. Yes. The MVP Portfolio was developed after a lengthy planning process designed to, among other things, support the achievement of state renewable energy requirements through infrastructure investments that minimized costs while meeting other state

[5] Dec. 16, 2010 Order at Para 3.

[6] MISO, "Multi Value Project Portfolio, Results and Analyses," January 10, 2012 ("MVP Report").

[7] MVP 7 also includes facilities that extend from the Missouri-Iowa border into Iowa's Ottumwa substation that are not an element of the Project, but are to be developed by the MidAmerican Energy Company.

policy objectives.[8] Initial stages of this process evaluated the costs of alternative wind zone configurations in light of tradeoffs between achieving renewable requirements through "regional" wind resources, which include the most productive (highest capacity factor) wind resources but require greater transmission infrastructure to enable delivery, and "local" wind resources, which often are less productive but require less new transmission. Through this process, MISO identified the scenarios with the lowest overall cost, which were scenarios that combined local and regional resources. The MVP Portfolio was designed to ensure delivery of these wind resources sufficient to meet state renewable energy requirements and other state initiatives, while minimizing costs. Thus, the Project was developed as an element of a cost-effective approach to achieving state renewable energy targets and other state initiatives, while providing other economic and reliability benefits, thus indicating that the Project is needed, economically feasible, and in the public interest.

Q. How are the costs of MVPs recovered?

A. FERC has approved the recovery of MVP costs through MISO transmission tariffs.[9] The costs of MVPs are recovered through a uniform per mega-watt hour ("MWh") transmission charge applicable to all load-serving entities within MISO North and to those exporting power from MISO.[10]

IV. DESCRIPTION OF ANALYTICAL APPROACH

Q. What measures of economic outcomes do you evaluate in your analysis?

[8] MISO, "RGOS, Regional Generation Outlet Study," November 19, 2010, particularly Sections 4 and 5.

[9] Midwest Indep. Transmission Sys. Operator, Inc., 133 FERC ¶ 61,221 (2010).

[10] *See* MISO Tariff, Schedule 26A, Multi-Value Project Usage Rate, and Attachment MM, Multi-Value Project Charge. Note that exports to the PJM Interconnection system are not assessed MVP charges.

A. In my analysis, I develop quantitative estimates of the Project's impact on prices, production costs and emissions. As I describe below, these measures are used to evaluate the Project's impacts on social costs, consumer expenditures and environmental impacts, each of which have important implications for whether the Project is economically feasible and in the public interest, two of the five *Tartan* criteria.

Q: Why are these economic criteria important to determining whether the project is economically feasible and in the public interest?

A: From an economic perspective, overall social welfare is improved if electricity services can be provided at a lower economic cost. Projects or policies that lower the social costs of electricity services ensure that society's resources are used in the most efficient manner.[11] By lowering costs, such projects or policies are said to provide *net social benefits*. The economic costs of providing electricity services include all of the underlying costs of generating and transmitting electricity, which includes environmental externalities that impose social costs through their impact on public health and environment services (e.g., recreation).

Economic analysis of new projects or policies should also consider impacts to particular groups given that impacts to individual groups may differ from impacts to society as a whole. Distributional impacts can also be an important factor in determining whether a project or policy is feasible from an economic standpoint and is in the public interest.[12] My analysis considers impacts to consumers of electricity, including residences and businesses, by evaluating expected changes in consumer expenditures for electricity services.

[11] For example, Stokey, Edith and Richard Zeckhauser, *A Primer for Policy Analysis*, W.W. Norton & Company, 1978; Stiglitz, Joseph, *Economics of the Public Sector*, Third Edition, W.W. Norton & Company, 2000.
[12] *Id. See* also, Bonbright, James C., et al. *Principles of Public Utility Rates*, Public Utilities Reports, Inc., 2nd Edition, 1988.

Q. How do the economic measures in your analysis help inform your assessment of whether the Project is economically feasible and in the public interest?

A. All else being equal, changes in production costs provide a direct measure of the Project's impact on social cost and overall economic efficiency and well-being. For reasons I describe in detail below, changes in production costs also provide a good measure of how the Project would be expected to impact payments by customers in Missouri for electric energy service.

Changes in air emissions are another element of the Project's impact on social cost. For example, if the Project reduced emissions, which in fact is likely the case, it would lower the social costs of providing electricity, all else equal.

Although Missouri electricity customers generally do not buy electricity at wholesale market prices, changes in prices provide another useful metric for understanding the Project's economic impact. All else being equal, lower wholesale market prices provide an indication of lower costs of production (on the margin) and a more efficient wholesale market.

Q. Please provide a brief summary of your analytical approach.

A. Changes in prices, production costs and emissions are estimated in two steps. In the first step, a market model is used to estimate the market outcomes of interest – prices, production costs and emission costs – under different assumptions about the transmission infrastructure elements that are in service. A "study case" assumes the Project is in service, while the "base case" assumes the Project is not in service. The second step calculates the difference between outcomes in the "base case" and "study case" – this change in market outcomes captures the market impact from developing the new infrastructure.[13] In this section of my testimony, I describe the approach used to evaluate prices, production costs and emissions, with further detail provided in **Schedule TS-02**.

Q. Please describe generally how you estimate expected future market outcomes.

A. The analysis uses the PROMOD IV ("PROMOD") market simulation model to estimate market outcomes in Missouri (and MISO North) with and without the Project. PROMOD, which is marketed by ABB,[14] simulates the operation of the regional generation and transmission system. Using detailed information on generator operating characteristics and constraints, transmission system topology and limits, and customer loads, the model simulates market operations to determine market outcomes, including plant-level production, power flows, and locational prices. The geographic region covered in my PROMOD analysis includes a large portion of the Eastern Interconnection,[15] including all of MISO North, adjacent operating systems (including SPP and the PJM Interconnection), and other indirectly interconnected systems.

The PROMOD market simulation model and the data set employed in my analysis are identical to those used by MISO in its Transmission Expansion Plan ("MTEP"). These data include information on customer loads, transmission infrastructure, forecasted fuel prices, and

[13] My approach differs from the approach taken by MISO in its MVP Reports. MISO's analyses compare the results between a "with 17 MVP" case and a "but for" case that does not include any of the 17 MVPs, whereas my analysis compares the results between the "with Project" case including all 17 MVPs and a "without Project" case that includes only the other 15 MVPs, excluding MVP 7 and 8.

[14] ABB is a global company with a particular emphasis in industrial technology, including the electricity industry.

[15] The Eastern Interconnection includes roughly the eastern two-thirds of the "lower 48" (with the exception of portions of Texas) plus Canadian provinces to the east of Alberta.

existing and new generation resources. The scenarios I analyzed, in which certain assumptions are varied, are the same as those analyzed by MISO in MTEP16.[16] Assumptions about future market conditions are developed within the MISO stakeholder process, reflecting input from all market participants. **Schedule TS-02**, attached to this testimony, further describes the PROMOD analysis and the data set that was used.

The PROMOD analyses were run for two future study years, 2025 and 2030, using five different scenarios for each year.[17] These scenarios, which are described further below, contain different assumptions about load growth and policies, and therefore allow an assessment of the relative robustness of the study results across a range of possible futures.

Q. What is the source of data used in the PROMOD model?

A. My PROMOD analysis relies on data from the PowerBase database maintained by ABB with modifications made by MISO. This database includes highly detailed and reliable data about the current transmission system, current generation resources and future loads, in combination with appropriate assumptions about future infrastructure changes, particularly new transmission and wind resources that would occur in association with the Project. The database's geographic scope is expansive, covering nearly the entire Eastern half of the United States, thus necessitating information on many different systems, most of which are outside of Missouri. Modifications to the ABB database made by MISO Staff reflect its system-specific knowledge, technical input from all MISO market participants, including transmission and generation owners, and review undertaken through a stakeholder process, providing opportunity for input by all MISO market participants.

[16] MISO Transmission Expansion Plan 16 "MTEP16". MISO, "MTEP16, MISO Transmission Expansion Plan," Final Report, pp. 98-100.
[17] 2025 and 2030 are the same years utilized by MISO in its MTEP16 analyses.

Q. Why is it appropriate to analyze the Project using a simulation of energy market outcomes?

A. A market simulation model such as PROMOD is necessary to analyze the Project's economic impacts. Because impacts will depend on comparison of market outcomes with and without the Project, a tool that allows such a counterfactual comparison, while holding all else equal, is required. PROMOD is such a tool. Moreover, accurate estimates of differences in electricity market outcomes must account for how the Project interacts with other resources in the system and how it relieves transmission congestion to enable the flow of electricity of over greater distances. Reliably accounting for these interactions is essential to accurately measuring impacts for any new piece of electricity infrastructure, but is particularly critical for transmission infrastructure such as the MVPs that are designed to enable the delivery of distant wind resources[18] and relieve transmission congestion. In addition, the Project has not yet been constructed and, once constructed, would be in-service for many decades. As a result, any evaluation of the economic feasibility of a project such as this must utilize simulations to evaluate market outcomes many years into the future. A market simulation tool, such as PROMOD, is necessarily to meeting these conditions for a reliable analysis of the Project's impacts.

Q. Please describe generally the analysis of prices.

A. Within organized wholesale markets, such as MISO and SPP, electricity prices are developed for individual "nodes" on the transmission system. PROMOD estimates these "nodal" market prices, which commonly are referred to as locational marginal prices, or

[18] In the case of the Project, it also enables the delivery of wind resources in North Missouri.

"LMPs."[19] The hour-by-hour LMP values produced by the PROMOD analysis were used, along with the amount of load served from each of the pricing nodes, to develop load-weighted average wholesale energy prices. This load-weighted average wholesale energy price for Missouri, which I refer to as the Missouri LMP, reflects all nodes in the state, including those in MISO, SPP, and other systems within Missouri. The difference between the Missouri LMP without the Project and the Missouri LMP with the Project represents the wholesale energy price effect from implementing the Project. If this difference is negative, as turns out to be the case, then this is an indication that the Project would be expected to lower average wholesale electric energy prices.

Q. Please describe generally the analysis of production costs.

A. My testimony provides estimates of the change in production costs to supply Missouri load associated with the Project. I refer to these as Missouri Production Costs. These costs reflect the fuel, variable operations and maintenance, emission allowance, and start-up costs associated with supplying Missouri load, adjusted for net sales and purchases of power with areas outside of Missouri, including areas within and outside of MISO. Missouri Production Costs reflect the costs to supply all Missouri loads, including those located in MISO, SPP and other systems. I also estimate the change in production costs for all of MISO North, which reflects the fuel, variable operations and maintenance, emission allowance, and start-up

[19] Differences in LMPs from location to location occur because of differences in marginal losses as well as the presence of congestion. When congestion is present, it is not possible to exploit fully differences in marginal generating costs at different locations and LMPs in transmission-constrained areas will rise above LMPs outside those transmission-constrained areas.

costs associated with supplying all MISO North load, adjusted for net sales and purchases of power with areas outside of MISO. I refer to these as MISO Production Costs.

Q. Do these production cost estimates account for net sales and purchases made by load-serving entities ("LSEs") in Missouri?

A. Yes, they do. To serve their customer's loads, LSEs in Missouri can own generation facilities, with the costs of owning and operating these facilities, including production costs, being recovered through the rates charged to their customers. These generation facilities may produce less than, greater than or exactly the amount consumed by LSE customers. When there is excess supply, these LSEs realize positive net revenues from sales to the wholesale market, with some portion (and potentially all) of revenues in excess of costs returned to customers. Likewise, when LSEs rely on market purchases to meet some portion of its customer loads, the cost of these purchases, which would reflect wholesale market prices and not production costs, are included in customer rates.

Because these net sales and purchases (relative to load) affect the LSE's cost to serve load, an adjustment to account for them is appropriate. Consider the impact of a project that reduces both LMPs and production costs for a LSE that generates more power than its load consumes. For this LSE's customers, the sale of excess energy provides a benefit by offsetting a portion of the production costs of meeting their load. If the project reduced LMPs, this would reduce the net revenues earned from these sales, which could make customers worse off (i.e., higher payments) if this reduction in net sales revenue was larger than any production cost savings created by the project. By adjusting production cost estimates to account for net sales and purchases (at appropriate wholesale market prices), my approach accounts for such a possibility, although, as it turns out, production costs decline with the Project in service in all scenarios evaluated, even after accounting for any potential reductions in the revenues from power sales.

Q. Do the estimated LMPs and production costs reflect ancillary services requirements?

A. Ancillary services are services provided by resources to ensure reliable, secure and efficient operation of the power system. In MISO, these services include operating reserves (spinning and supplemental) and regulation. The PROMOD analysis incorporates MISO's operating reserve requirements, but does not account for regulation requirements. However, the costs of meeting these requirements generally reflect a small share of overall production costs.[20]

Q. Do production costs reflect social costs?

A. Yes. Social costs include the opportunity cost of using resources, including the various electricity production costs described above, such as the use of fuel to produce electricity or the use of labor to operate power plants. Thus, the costs captured by the estimated production costs are all social costs. Social costs also include welfare losses associated with economic decisions, including environmental impacts associated with the production of electricity. As I discuss below, to capture these types of impacts, I separately calculate the change in emissions from development of the Project.

[20] MISO reported that ancillary service payments accounted for 0.4 percent of wholesale costs, including energy and uplift payments. MISO, "MISO 2013 Annual Market Assessment Report," Information Delivery and Market Analysis, June 2014, at p. 9. For August 2016 to July 2017, estimated payments for regulation, spinning reserve and supplemental reserve services are $71 million, while total payments through all MISO markets, including energy, capacity and uplift, was over $25.3 billion. MISO, "Monthly Market Assessment Report June 2017," Market Evaluation and Design, August 10th, 2017 at pp 19, 24-26; MISO, "Informational Forum," at p 15; and MISO, "Corporate Information Fact Sheet," accessed on September 13, 2017, available at https://www.misoenergy.org/AboutUs/Pages/FactSheet.aspx

Q. Do production cost estimates also provide a reliable means of assessing expected changes in retail payments by Missouri customers?

A. Yes. Missouri customers are served by LSEs that charge prices that are based on the LSE's cost of service. These LSEs include investor-owned utilities regulated by the Commission, and electric cooperatives and municipal utility companies that establish prices independent of state regulation. When customers are served by utilities with rates that are set based on the cost-of-service, the prices charged to customers will generally reflect costs of producing power, rather than wholesale market prices. As a result, a reduction in the cost of producing power will generally flow through to customers in the form of lower rates. Because Missouri customers are served by utilities that charge rates that are set based on the cost-of-service, changes in production costs of Missouri LSEs provide an appropriate means of estimating *expected changes* in retail payments for electric energy by Missouri customers from development of the Project.[21]

Q. Does the PROMOD analysis reflect the complete set of wholesale electricity market benefits from the Project?

A. No. The PROMOD analysis quantifies the lower wholesale electric energy prices and production costs that will result from the Project, but it does not quantify other potential wholesale electricity market benefits such as lower operating reserve and capacity requirements,

[21] The actual rates charged to Missouri customers are developed based on the utility's cost of service reflecting valid actual expenditures encompassing distribution, transmission and generation. For regulated utilities, rate setting occurs through rate cases heard by the Commission. By contrast, my analysis estimates *expected* changes in rates associated with portions of generation and transmission costs expected to change due to the Project's development. These estimates support determinations of whether the Project should be awarded a CCN and not for the purpose of determining specific modifications to customer rates. Thus, the appropriate data and methods differ from those used in establishing rates charged to customers. Actual change in rates due to the Project's development may differ from my estimates for many reasons, but the expected changes I model would be indicative of those actual rate changes. Sensitivity analysis performed under many futures scenarios tests the robustness of my findings to uncertainty in future market conditions.

which in turn would lead to lower costs of fulfilling these requirements.[22] Reductions in operating reserve and capacity requirements would likely arise if the Project reduces congestion that can limit the flow of capacity and reserves across the MISO North footprint. By reducing these limitations, fewer capacity and reserve resources would likely be needed to maintain a reliable transmission system, thus lowering costs. Consequently, focusing just on the change in wholesale electric energy price and production costs from the PROMOD analysis therefore will likely understate the full range of market benefits that can be expected from the Project.

Q. Please describe generally the analysis of air emissions.

A. The production of electric energy results in environmental impacts, including air emissions. The PROMOD analysis estimates emissions of CO_2, NO_X, SO_2 and mercury. For CO_2 emissions, changes in emissions are measured across the entire MISO footprint. I refer to these as MISO CO_2 Emissions. It is appropriate to evaluate changes in CO_2 emissions over the entire MISO North footprint because CO_2 emissions have the same impact regardless of where they are emitted. In contrast, NO_X, SO_2 and mercury emissions are measured only from generation facilities within Missouri. I refer to these as Missouri NO_X emissions, Missouri SO_2 emissions, and Missouri Mercury Emissions. For these emissions, it is appropriate to analyze impacts based on emissions from in-state sources because their impact depends on the proximity of the receptor to the original source.

My analysis estimates the change in emissions from the development of the Project. If emissions are lower with the Project, which happens to be the outcome, this indicates

[22] In its analyses, MISO quantifies a broader range of economic impacts, such as reductions in operating reserve costs, planning reserve margins, transmission line losses, and future wind turbine and transmission investment. MVP Report, at pp. 50-68; MISO, "MTEP14 MVP Triennial Review, A 2014 review of public policy, economic, and qualitative benefits of the Multi-Value Project Portfolio," September 2014 ("Triennial Report"), at pp. 25-43.

the environmental impacts, and thus social costs, are lower with the Project in service, thus promoting the public interest in reducing the environmental impacts of providing electricity service. For certain emissions, including SO_2 and CO_2 in certain scenarios,[23] estimated production costs include the cost of allowances required for regulatory compliance. I provide actual emission levels, as well accounting for these allowance costs, because the cost of allowances included in production costs may differ (higher or lower) from the social cost of the these emissions.[24]

Q. Does the PROMOD analysis reflect other benefits from the Project, such as reliability improvements?

A. No. The PROMOD analysis only considers changes in energy market outcomes, and does not evaluate improvements in reliability from the Project. The MISO analyses address the reliability benefits of MVP projects in general,[25] while Mr. Kramer's direct testimony addresses specific reliability benefits associated with the Project.

Q. Does your analysis assume the Project would support the development of additional wind resources?

A. Yes. Absent the Project, the quantity of wind resources that could be reliably delivered would be diminished. As a result, the Project supports the achievement of Missouri's renewable energy requirements and other state energy initiatives, thus demonstrating both that the Project is needed and that it is in the public interest.

[23] CO_2 allowance costs are assumed in the Regional CPP and Sub-Regional CPP scenarios.
[24] My analysis does not account for any reductions in allowance prices that could arise due to reduced demand for allowances.
[25] For example, MVP Report, pp. 43-47.

Aside from the Project's new transmission facilities, the only difference in model inputs between the "with Project" case and "without Project" case is the quantity of wind power assumed in each case. The quantity of new wind power resources is reduced in the "without Project" case based on MISO's determination that less wind generation capacity can be reliably supported. My analysis reduces wind supply from specific resources that would be enabled by the Project based, in part, on analysis performed by MISO. Across scenarios, wind supply is reduced by 1,654 to 2,744 MW in 2025 and 1,762 to 3,340 MW in 2030. These data assumptions are described in further detail in **Schedule TS-02**.

Q. What specific scenarios are included in your analysis?

A. The following five scenarios were included:

i) Business as Usual – includes all current policies, regulations and trends, with demand and energy growth at expected ("50/50") levels;

ii) Low Demand – same as the Business as Usual scenario, but with lower demand and energy growth levels, and lower natural gas prices;

iii) High Demand - same as the Business as Usual scenario, but with higher demand and energy growth levels, and higher natural gas prices;

iii) Regional Clean Power Plan ("Regional CPP") - assumes "footprint-wide" resource changes to comply with the Clean Power Plan, such as new resource development (i.e., new wind and solar), and retirement of coal resources; and

iv) Sub-regional Clean Power Plan ("Sub-regional CPP") - assumes "zonal and state" level resource changes to comply with the CPP through new resource development (largely wind and solar, more extensive than in the Regional CPP scenario), and retirement of coal resources (more extensive than the Regional CPP scenario).

These five scenarios are described more completely in **Schedule TS-02**.

Q. The Clean Power Plan has been stayed by the United States Supreme Court and there is speculation the Trump administration will repeal it. What then is the relevance of the Regional CPP and Sub-regional CPP cases?

A. I acknowledge that there is a high likelihood that the CPP or similar federal climate legislation will not be implemented in the near term. However, independent of the CPP, market forces and policy actions at the state level could lead to comparable, if not more extensive, changes in electricity generation and use than would be achieved solely through compliance with the CPP. The CPP scenarios I evaluate assume changes in coal-fired retirements and incremental renewable development that go beyond business-as-usual expectations, but are consistent with these factors. One key driver of change is the dramatic decline in the price of natural gas from the "shale revolution" that has reduced the competiveness of coal-fired resources relative to natural gas-fired generation, precipitating extensive retirements.[26] Persistent downward pressure on natural gas prices would place continued pressure on the viability of coal-fired generation. A combination of drivers may lead to expanded renewable resource development, including more aggressive state-level renewable energy requirements, continued decline in renewable technology costs through technological improvements, and increased demand from customers, particularly large industrial and commercial enterprises with a desire to procure power from low-carbon sources.[27] Finally, even if the near-term likelihood of federal action on climate policy is low, the Project will be in

[26] United States Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability, August 2017; Houser, Trevor, Jason Bordoff and Peter Marsters, "Can Coal Make a Comeback?", Columbia Center on Global Energy Policy, April 2017.
[27] *See, e.g.*, Business Renewables Center, BRC Deal Tracker, http://businessrenewables.org/corporate-transactions/.

service for many decades into the future when the likelihood of federal action may be very different.

V. PRESENTATION OF RESULTS

Q. Have you prepared schedules summarizing your results?

A. Yes. The results of the analysis are described in Table 1 through Table 9, which are provided in **Schedule TS-03**.

Q. Please describe the Project's impact on Missouri LMPs, as shown in Table 1.

A. The PROMOD analyses involve a comparison of the "with Project" and "without Project" cases for two different study years (2025 and 2030) and five different scenarios within each study year. **Table 1** provides the weighted average LMP values for Missouri from these analyses. Wholesale electric energy prices in Missouri, as measured by the average Missouri LMPs reported in **Table 1**, are lower with the Project in service across all scenarios evaluated. Across these scenarios, the reduction in prices in Missouri from the Project range from $0.28 to $0.64 per MWh in 2025, and $0.32 to $0.87 per MWh in 2030. The percent reduction in prices ranges from 0.56 to 1.05 percent in 2025, and 0.69 to 1.06 percent in 2030.

Q. Over what geographic areas do you consider changes in production costs?

A. In my analysis, I consider changes in production cost to the MISO North footprint and to Missouri. Production cost reductions to Missouri provide information about the state-wide impacts to Missouri that are directly relevant to determining whether the Project is in the public interest and economically feasible from the standpoint of Missouri citizens. In addition, changes in production costs are measured for the MISO North footprint, which captures a broader, regional view of public interest and economic feasibility. Because the MVP Portfolio involves projects that are being implemented in states across the northern portion of the MISO footprint, with many states similarly considering approvals that produce both in-state and out-of-state positive benefits (including benefits to Missouri citizens), and because the MVP Portfolio was developed as a region-wide, integrated solution, such a broader regional view is appropriate to developing an informed view of whether the Project is in the public interest and whether it is economically feasible.

Q. Please describe the Project's impact on Missouri Production Cost, as shown in Table 2.

A. Production costs in Missouri are lower with the Project in service across all of the scenarios evaluated. Across the scenarios evaluated, the reduction in Missouri Production Costs range from $13.5 million to $82.9 million in 2025, and $12.4 million to $102.5 million in 2030. Note that the reduction in Missouri Production Costs is estimated for a single year, 2025 and 2030. I would expect similar reductions in years prior to, between, and subsequent to these years, which, as I show below, will make cumulative reductions much larger. The percent reduction in Missouri Production Costs ranges from 0.81 to 1.39 percent in 2025, and 0.71 to 1.53 percent in 2030.

Q. Please describe the Project's impact on MISO Production Costs, as shown in Table 3.

A. Production costs in MISO North are lower with the Project in service across all of the scenarios evaluated. Across the scenarios evaluated, the reduction in MISO Production Costs range $105.2 million to $283.4 million in 2025, and $120.4 million to $307.2 million in 2030. The percent reduction in MISO Production Costs ranges from 0.97 to 1.27 percent in 2025, and 0.80 to 1.30 percent in 2030. As with the Missouri Production Costs, I expect similar reductions in MISO Production Costs in years prior to, between, and subsequent to 2025 and 2030.

Q. Please describe the change in Missouri Net Costs, Tables 4 and 5.

A. **Table 4** presents a conservative depiction of the estimated net cost of the Project that reflects both changes in production costs (over a 20-year period) and MISO Missouri LSEs' estimated share of the transmission charges that will arise from the Project. The net cost reflects the Project's social cost due to changes in production costs and Missouri's share of the transmission charges that will be assessed due to the Project's development and operation costs. Because the rates charged by Missouri LSEs reflect each entity's cost-of-service and because the Project's costs are recovered through rates charged to the LSEs that serve Missouri customers, these estimates of net costs also provide an appropriate estimate of the changes in electric energy payments by Missouri customers that will arise from the Mark Twain Project. **Table 4** is a one page summary containing estimates of the reduction in net costs for Missouri from the Project for each of the five scenarios over the entire 20-year period that I studied. I refer to these net costs as Missouri Net Costs. **Table 5**, which consists of five pages, provides year-by-year detail of the reductions in production costs and estimates of the present value of these reductions for each of the scenarios.

The Missouri Net Costs of the Project is calculated in several steps. To estimate the annual change in energy costs, I use estimates of Missouri Production Cost changes, which are adjusted to account for net sales and purchases of electric power by these LSEs. Total cost impacts are estimated for the 20-year period, 2020-2039. I selected 2020 as the beginning year for this evaluation since that represents the first year when all elements of the Project are expected to be fully energized. I used the 2025 and 2030 PROMOD-produced electric energy cost amounts to determine a growth rate between these two years, and used this growth rate to interpolate or extrapolate the values for the other years in the 20-year comparison period. The figures in **Table 5** include the nominal annual values and the present value of the total change over the 20-year period as of the present day (assumed to be mid-year 2017). These discounted present values are computed using alternative discount rates of 3.0 and 8.2 percent, which are the same discount rates used by MISO in its MVP analyses.

By comparing electric energy production costs in the "with Project" and "without Project" cases, I was able to determine the reduction in customer costs for each scenario (column [A], **Table 4**). As indicated, in **Table 4**, from the estimated total costs for electric energy, I subtracted an estimate of the transmission charges arising from the investment costs for the Project that will be borne by MISO Missouri LSEs as well as an estimated variable expense component. The remainder provides an estimate of the reduction in net costs that can be expected for Missouri customers as a result of the Project. The **Table 4** and **Table 5** estimated reductions are likely conservative because they reflect expected reductions in wholesale electric energy costs, and therefore payments (net of increased transmission payments), but not reductions in costs for other components of electricity supply such as capacity and operating reserves, which could also be significant. In addition, these estimates also do not account for other social costs and benefits, such as improvements in reliability, access to new renewable resources, and reductions in air emissions, which I discuss below. **Schedule TS-02** provides a more detailed explanation of the computational procedures employed in developing **Table 4** and **Table 5**.

Q. What do Table 4 and Table 5 indicate?

A. The results of my analysis reported in **Table 4** and **Table 5** show that the Project will lead to substantial reductions in the ultimate electric rates paid by customers in Missouri as compared to the rates that would be paid without the Project. Under the Business as Usual scenario, the present value of reductions in wholesale electric energy costs from the Project is $285.2 million (at a discount rate of 8.2 percent). The present value of the transmission charges arising from the Project is $28.0 million, resulting in a net reduction in energy costs to be ultimately borne by Missouri customers of $257.2 million (i.e., $285.2 million minus $28.0 million). Thus, there is a 10.2-to-1 ratio of benefits (in terms of reductions in energy costs) to costs (in terms of Missouri's share of Project costs). Table 4 also shows that the reduction in costs would vary across the other scenarios I evaluated, with reductions in net costs ranging between $81.8 million and $689.1 million. Across the scenarios I evaluated, the ratio of benefits to costs ranges from 3.9-to-1 to 25.4-to-1. When the analysis is performed using a lower 3 percent discount rate, the reduction in net costs increases in each scenario and ranges from $146.6 million in the Low Demand scenario to $1,266.4 million in the Sub-Regional CPP scenario. Across these cases, the ratio of benefits to costs ranges from 5.2-to-1 to 37.0-to-1. Thus, across all of the scenarios evaluated, the Project's benefits would far outweigh the costs of the Project's development to Missouri.

Q: Has MISO developed estimates of economic impacts similar to those developed in your analysis?

A: Yes. In its initial evaluation of the MVP Portfolio, performed prior to approval of the MVP Portfolio by the MISO Board, MISO performed an economic analysis similar to the analysis I undertake here.[28] MISO is obligated to undertake "triennial" updates of this initial study every three years, and has released the first update in 2015.[29] In addition, MISO has performed a "limited review" evaluation in interim years after the first Triennial Updates as a

[28] MVP Report.

[29] Triennial Report.

part of the MTEP15 and MTEP16 process.[30] MISO's analyses differ in several respects from the analysis I undertake. First, MISO's analyses consider multiple quantified and unquantified economic impacts, including the changes in production cost that I analyze.[31] Second, while my analysis considers the impact of the Project alone (assuming all other MVPs are in service), MISO's analyses consider the impact of all of 17 MVPs in the MVP Portfolio. Thus, the two analyses provide complementary information on the Project's economic benefits.

Q. Are MISO's analyses of the impact of the MVP Portfolio on the MISO region consistent with your findings?

A. Yes. In its original MVP Report, MISO concluded that the MVP Portfolio would provide \$6.8 to \$32.8 billion in benefits in excess of costs to the MISO region across scenarios evaluated (in present value terms, as of \$2011).[32] In addition, the Portfolio would enable the delivery of 41 million MWh of wind energy, which would support achievement of state renewable energy requirements and policies.[33] In the triennial update report, MISO estimated net economic benefits of \$13.1 to \$49.6 billion (present value, as of \$2014) from development of the MVP Portfolio.[34] The most recent MTEP analysis has found similar net benefits, ranging from \$19.2 to \$57.3 billion (in present value terms).[35] These quantified changes in economic

[30] For example, see MTEP16, Section 7.2, MVP Limited Review.
[31] MISO's limited review analysis in MTEP15 and MTEP16 only updates estimates of production cost savings based on the MTEP15 and MTEP16 databases, but not other quantified benefits.
[32] MISO's Triennial Report reports net benefits over 20 to 40 years of \$8.8 to \$31.0 billion (in \$2014).
[33] All MISO study results reported in this testimony assume benefits over a 20-year to 40 year horizon. Results from the 2012 study are reported in 2011 dollars, while results from the Triennial Study are reported in 2014 dollars. MVP Report, pp. 48, 49, 69.
[34] The Triennial Report evaluated the business as usual high and low demand scenarios, with the reported value reflecting an average of these two scenarios. Triennial Report; "MTEP14 MVP Triennial Review Business Case.xlsx".
[35] The estimates reflect updated estimates of production cost savings based on PROMOD analysis of the MTEP16 database, and estimates of other benefits developed in the MVP Triennial Review based on MTEP14 databases. MTEP16, p. 167.

costs reflect both reductions in production costs, which are considered in my analysis, as well as other economic impacts that are not considered in my analysis.[36] Thus, as in my analysis, MISO finds that the Project – as an element of the MVP Portfolio – provides net benefits to the MISO North region.

Q. Is MISO's analysis of the impact of the MVP Portfolio on Missouri consistent with your findings?

A. Yes. Along with analyzing impacts across the MISO North footprint, MISO also assesses the impact of the MVP Portfolio for each of seven individual "zones" that comprise MISO North, one of which is the Missouri portion of MISO (see, e.g., page 7 of the MISO MVP Report). The MISO report concludes that there are substantial benefits from the MVP Portfolio in each zone, thus indicating that the MVP Portfolio will provide widespread benefits all regions within the MISO footprint. In the MVP Report, the Triennial Update, and subsequent MTEP15 and MTEP16 reviews, MISO finds that the benefits to Missouri from the development of the MVP Portfolio would far outweigh the associated costs of developing the Portfolio. In the original MVP Report, MISO finds that the MVP Portfolio would result in net benefits of $0.7 to $4.0 billion to MISO Missouri, with a ratio of benefits to costs ranging from 1.8 to 3.2 across scenarios.[37] In the Triennial Report, MISO found substantially higher net benefits to Missouri: total benefits were estimated at $1.3 to $2.0 billion (present value), with a ratio of benefits to

[36] These other benefits include reductions in operating reserve and capacity requirements, wind turbine investment and future transmission investment.

[37] Net benefits are shown here across a 20 - 40 year horizon for the business as usual scenario in 2017$ assuming a 2.5 percent inflation rate as in the MTEP16 analysis. MVP Report, p. 86; "MVP Detailed Base Case.xlsx" and MTEP16 p 102.

costs of 2.33 to 2.46.[38] In the most recent limited review, these net benefits are similar, with a ratio of benefits to costs of 1.6 to 2.0.[39] Thus, as in my analysis, MISO finds that the Project – on its own or as an element of the MVP Portfolio – provides net benefits to Missouri.

Q. Please describe the Project's impact on air emissions, Table 6 through Table 9?

A. The impact of the Project on emissions of CO_2, NO_X, SO_2, and mercury are shown in **Tables 6** to **Table 9**. Across all of the scenarios, air emissions fall with the introduction of the Project. As shown in **Table 6**, with the Project in service, MISO CO_2 Emissions are reduced by 2.15 to 3.63 million tons of CO_2 equivalent ("TCO_2e") in 2025, and 1.77 to 3.77 million TCO_2e in 2030. These reductions reflect a 0.73 to 1.11 percent reduction in 2025, and 0.81 to 1.22 percent reduction in 2030. Changes in Missouri NO_X, SO_2 and Mercury Emissions are similar in percentage terms. For example, the percent reduction in Missouri NO_X Emissions reported in **Table 7** is 0.22 to 0.62 percent in 2025, and 0.17 to 0.70 percent in 2030. Reductions in in-state emissions from the Project occur despite the fact that total power generated by in-state sources rises when the Project is in service. This reduction in the emission-intensity of power generation arises because of the increase in wind resources enabled by the Project displaces generation from other higher-emitting resources. For example, in the Business as Usual scenario, in-state power generation increases by 506.9 GWh in 2025 and 290.3 GWh in 2030, representing 0.58 and 0.32 percent increases in total in-state generation. However, despite

[38] "MTEP14 MVP Triennial Review Business Case.xlsx", adjusted to 2017$ assuming a 2.5 percent inflation rate as in the MTEP16 analysis. Note that differences in the ranges of impacts reflects, in part, differences in the range of scenarios considered in each evaluation. In particular, evaluations subsequent to the initial MVP Report only consider alternative discount rates and gas price forecasts, whereas as the initial MVP Report considers scenarios with alternative demand and policy assumptions, as well.

[39] MTEP16, p. 169.

this increase in output, Missouri NO_X Emissions fall by 0.48 percent in 2025 and 0.44 percent in 2030, Missouri SO_2 Emissions fall by 0.56 percent in 2025 and 0.59 percent in 2030 (**Table 8**), and Missouri Mercury Emissions decline by 0.55 percent in 2025 and 0.55 percent in 2030 (**Table 9**). These reductions in air emissions further demonstrate that the Project is in the public interest.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345-kV Electric Transmission Line from Palmyra, Missouri, to the Iowa Border and an Associated Substation Near Kirksville, Missouri.	))))))))))	File No. EA-2017-0345

AFFIDAVIT OF TODD SCHATZKI

STATE OF MASSACHUSETTS)
) ss
CITY OF BOSTON)

Todd Schatzki, being first duly sworn on his oath, states:

1. My name is Todd Schatzki. I work in the Boston, Massachusetts, and I am employed by Analysis Group, Inc.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Ameren Transmission Company of Illinois consisting of 31 pages, and Schedule(s) TS-01, TS-02, and TS-03 all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

[signature]
Todd Schatzki

Subscribed and sworn to before me this 14th day of September, 2017.

[signature]
Notary Public

My commission expires:

KATHERINE A. BARBER
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 6, 2023

TODD SCHATZKI, Ph.D.
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Dr. Schatzki is an expert in energy and environmental economics and policy, and specializes in the application of microeconomics, econometrics, and data analysis to complex business and policy problems. He has worked with clients on corporate strategy, public policy design, and problems arising in regulation and litigation.

Dr. Schatzki has worked extensively on the design of electricity markets, analysis of wholesale electricity markets, economic analysis of energy and environmental regulations, asset valuation, resource planning and procurement, utility ratemaking and retail electricity markets. He has submitted testimony to both state and federal energy commissions. His research has been supported by organizations such as the Electric Power Research Institute, Edison Electric Institute, Federal Energy Regulatory Commission, and National Association of Regulatory Utility Commissioners. His work has appeared in journals such as the *Journal of Environmental Economics and Management, the Electricity Journal*, *Public Utilities Fortnightly*, and *AEI-Brooking Joint Center for Regulatory Studies.* He has also provided litigation support in many cases, including several high profile cases involving alleged wholesale electricity price manipulation and the implications of such manipulation for derivative contracts.

Prior to joining Analysis Group, he had research and consulting affiliations with the Harvard Institute for International Development and the International Institute for Applied Systems Analysis (Vienna, Austria), and was an economist at LECG, LLC and National Economic Research Associates.

EDUCATION

1998 Ph.D., Public Policy, Harvard University, Cambridge, MA

Specialized Fields: Microeconomics, econometrics, industrial organization, natural resource and environmental economics

- Doctoral Fellow, Harvard University, Cambridge, MA (1993-1995)
- Crump Fellowship, Harvard University, Cambridge, MA (1995-1996)
- Pre-doctoral Fellow, Harvard Environmental Economics Program

1993 M.C.P., Environmental Policy and Planning (Urban Studies and Planning,), M.I.T., Cambridge, MA

1986 B.A., Physics, Wesleyan University, Middletown, CT

SCHEDULE TS-01

PROFESSIONAL EXPERIENCE

2005-present	Analysis Group, Inc.
2001-2005	LECG, LLC, *Managing Economist*
1998-2001	National Economic Research Associates, Inc., *Senior Consultant*
1997-1998	Harvard Institute for International Development, *Consultant*
1996-1997	Department of Economics, Harvard University, *Teaching Fellow and Research Assistant*
1994	International Institute for Applied Systems Analysis (IIASA)
1992	Toxics Reduction Institute, University of Massachusetts
1987-1991	Tellus Institute, *Research Associate*

SELECTED CASE WORK

Energy

- **ISO New England.** For the New England Power Pool (NEPOOL) 2016 Economic Analysis, analysis of Forward Capacity Market implications of alternative scenarios with varying assumptions about retirements and clean energy resources.
- **New England Electricity Markets.** Confidential assessment of interactions between state policies affecting electric power resources, including long-term contracts, and wholesale electricity markets.
- **New York Independent System Operator**. Demand curve reset for the New York ISO ICAP market including development annual updating process between resets and ICAP Demand Curve parameters.
- **Confidential Client.** Analysis of factors contributing to assessment of fines associated with an operational incident in the context of a shareholder derivative suite.
- ***FERC v. Barclays***. Provide analysis of allegations of manipulation of western U.S. electric power exchange markets.
- **ISO New England.** Assessment of framework for evaluating capacity market offers from elective transmission projects for market mitigation.
- **Southwest Power Pool Power Suppliers**. Provides analysis and testimony related to what types of costs are appropriately short run marginal costs and thereby should be incorporated into energy market resource offers.
- **New York Independent System Operator**. Evaluation of capacity market rule changes including a forward market structure and multi-year price lock-in, including quantitative economic analysis of changes in market outcomes under alternative market structures.
- **Ameren Missouri**. Analysis of the economic impact of the Mark Twain Project, a new transmission project designed to support renewable energy requirements and other objectives (using PROMOD)
- **ISO New England.** Assistance to the ISO New England market monitor in the development of a de-list offer model consistent with new market rules.

SCHEDULE TS-01

- ***Zaremba v. Encana***. Evaluate operating agreements, the structure of the oil and gas industry, and trends in gas pricing in regards to antitrust claims in the market for oi land gas leases.
- **ISO New England.** Assistance in the development of a Winter fuel assurance programs for 2013/14, 2014/15 and 2015/16, including oil inventory, dual fuel, liquefied natural gas and demand response programs
- **Ameren Transmission.** Analysis of the impact of the Multi Value Project No. 16, a new transmission project, on energy market competition in Illinois (using PROMOD).
- **Vancouver Energy**. Assessment of economic impacts of a new energy distribution terminal, including change in economic activity, property value impacts and changes in rail congestion
- **ISO New England.** Assessment of the economic costs associated with winter 2013/2014 reliability programs, including oil inventory, dual fuel, liquefied natural gas and demand response programs
- **ISO New England.** Assessment of and testimony regarding the economic and reliability impacts of proposed capacity market rules introducing new performance incentives
- **ITC Midwest.** Analysis of and testimony regarding the LMP and production cost impacts of new transmission infrastructure (using PROMOD)
- **Entergy.** Evaluation of economic damages associated with an alleged contract breach
- **Ameren Transmission.** Analysis of the impact of the Illinois River Project, a new transmission project, on energy market competition in Illinois (using PROMOD)
- **Dayton Power and Light.** Evaluation of the aggregate benefits created by a proposed rate plan
- **Corporation with distribution companies across multiple jurisdictions.** Regulatory assessment considering current ratemaking models, regulatory environment and alternative ratemaking structures
- **ISO New England.** Assessment of the costs, feasibility and effectiveness of technical options to securing fuel supply for gas-fired generators
- **ISO New England.** Assessment of reliability risks and potential market and regulatory solutions to electric-gas interdependencies
- **Pacific Gas and Electric.** Assessment of ratemaking issues, including cost of capital adjustments, associated with a gas pipeline safety plan
- **Confidential Technology Company.** Analyzed the regional economic impacts of a prototype biofuels production facility at two potential development sites using the IMPLAN model.
- **ISO New England.** Statistical analysis of the performance of resources responding to system contingencies
- **Direct Energy.** Assistance developing regulatory options for promoting retail competition in Pennsylvania, including development of customer service auctions
- **ISO New England.** Assistance developing design enhancements for the region's Forward Reserve Markets
- **Confidential Client.** Analysis of energy and capacity market implications of a potential asset agreement (using GE's Multi-Area Production Simulation Software)
- **Confidential Client.** Analysis of fleet turnover decisions and outcomes (using GE's Multi-Area Production Simulation Software)
- **Confidential Regulated Utility.** Development of a white paper on transmission planning and policy needed to support legislative and regulatory goals for renewable development

- **Commonwealth Edison.** Analysis of appropriate ratemaking tools (cost of equity adjustment) in light of energy efficiency program requirements
- **New England Power Generators Association.** Analysis of impacts of proposed electric power company merger
- **Confidential Technology Company.** Development of a quantitative model of energy savings associated with end-use technological modifications..
- **Confidential Regulated Utility.** Development of a white paper assessing the potential for alternative ratemaking tools to mitigate multiple utility capital, load and service challenges
- **EDF Group.** Analysis of financial and credit implications of the sale of a portion of power generation assets
- **New England States Committee on Electricity.** Technical support and analysis related to design of regulations and wholesale electricity markets to achieve resource adequacy
- **National Grid Utilities.** Assistance developing ratemaking plans including revenue decoupling and associated revenue adjustments
- **NARUC and FERC.** Analysis of "best practices" in state policies for competitive procurement of retail electricity supply
- **New York ISO.** Analysis of single-clearing-price versus pay-as-bid market designs
- **Confidential System Operator.** Analysis of metrics for characterizing the economic value provided by regional transmission organizations
- **TransCanada.** Assessment of regulatory and finance issues involved in fuel adjustment clauses within long-term standard offer service contracts
- **New York ISO.** Analysis of market implications of fuel diversity issues
- **Confidential.** Analysis of alleged exercise and extension of market power in a wholesale electricity market, including statistical analysis of spot and real-time electricity markets and statistical modeling of outages using hazard model methods to examine potential physical withholding
- **Confidential.** Financial and strategic analysis of gas supply contracting alternatives
- **Confidential.** Analysis of value of generating assets using real options analysis
- **Confidential.** Statistical analysis of prices in the spot and forward markets using time-series methods for an energy trading firm in a federal proceeding related to the reasonableness of the terms of certain forward market contracts
- **Confidential.** Financial and strategic analysis of renewable generation technologies

Environment

- ***Florida v. Georgia.*** Analysis of economic issues related to current and proposed alternative apportionment of water between the states of Florida and Georgia before the U.S. Supreme Court.
- ***New Jersey DEP v. Occidental Chemical Corp. et al.*** One behalf of Maxus, assessment of reliability of analyses and conclusions reached regarding settlement of claims related to environmental contamination.
- **Chevron.** Development of a white paper on post-2020 climate policy for California
- ***New Jersey DEP v. ExxonMobil***. Assessment of methods for valuation of environmental contamination.

- **American Petroleum Institute.** Assessment of issues related to the impact of changes to National Ambient Air Quality Standard Requirements on oil and gas exploration and production
- **Greater Boston Real Estate Board.** Development of a white paper on mandatory building energy labeling/benchmarking policies
- **Little Hoover Commission.** Analysis of the economic and environmental consequences of a local climate policy plan implemented in the context of a state-wide cap-and-trade system
- **Exelon.** Analysis of the economic and market consequences of EPA's Clean Air Transport Rule
- **Chevron.** Assessment of lessons learned from Federal requirements for regulatory review for the potential development of state requirements
- **Western States Petroleum Association and Chevron.** Regulatory support and analysis related to climate policy in California, including submission of various comments and reports to the Air Resources Board
- **Honeywell.** Analysis of proposed limits on HFC consumption under domestic climate policy
- **Electric Power Research Institute.** Analysis of three 2006 studies on the economic impact of meeting the California carbon emissions reduction targets (in the California Global Warming Solutions Act of 2006)
- **Confidential.** Assessment of various policy issues in the design of national climate change policies, including market-based policies, approaches to cost containment, offset projects, and non-CO_2 GHGs
- **Confidential.** Quantitative analysis of the impacts for technology, consumers and asset owners of a market-based domestic climate policy
- **Toyota.** Analysis of the economic value of emissions for a major auto manufacturer associated with alleged non-compliance with emissions control requirements
- **Barajas Airport.** Evaluated the regional economic impacts of runway expansions at the Barajas airport in Spain.

Finance and Commercial Damages

- **Confidential Client.** Analysis of factors contributing to assessment of fines associated with an operational incident in the context of a shareholder derivative suite.
- Analysis of financial and credit implications of the sale of a portion of power generation assets
- Analysis of bond pricing, transactions and holdings related to default of sovereign bonds
- Analysis of transfers between financial institutions within credit card networks
- Analysis of the impact of product taxes on firm market shares related to determination of payments under a settlement agreement
- Analysis of damages related to breached contract and appropriation of trade secrets in the development of a pharmaceutical product
- Analysis of damages from breach of commodity swap contract (petroleum)
- Analysis of allegations regarding mutual fund day trading, including analysis of trading patterns and calculation of dilution

Antitrust

- Analysis of alleged monopolization of energy price indices.
- Estimation of damages associated with an alleged monopolization and foreclosure resulting from a distribution agreement (retail consumer products)
- In a price-fixing case across multiple markets in the pharmaceutical industry, estimated overcharges and cartel periods based on a time-series analysis of price data
- Analysis of multiple antitrust claims (including foreclosure, monopolization, and vertical restraints) related to an alleged collusive distribution arrangement (retail consumer product)
- Analysis of alleged tying of aftermarket products and the provision of service, including evaluation of the alleged tie, competitive effects, and damages (office systems)
- Analysis of liability, timing, geographic scope, and damages issues for a petrochemical company facing potential price-fixing charges by DOJ and private parties
- Analysis of tying, monopolization, and patent abuse claims involving a patent licensing scheme for process and instrument patents (scientific equipment)
- Analysis of foreclosure, attempted monopolization of innovation markets, and damages claims arising from the termination of an investment/licensing agreement (medical devices)
- Estimation of damages related to alleged invalid patents and tying of products to patent rights associated with a process patent (scientific equipment)

ARTICLES AND PAPERS

"Beyond AB 32: Post-2020 Climate Policy for California" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2014.

"Three Lingering Design Issues Affecting Market Performance in California's GHG Cap-and-Trade Program" (with Robert N. Stavins), Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2013.

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Schedule TS-02:

Technical Appendix: PROMOD Modeling and Data

This Schedule provides a summary of the PROMOD IV ("PROMOD") model, data and assumptions used in analyzing the Mark Twain transmission project (the "Project") proposed by Ameren and the methodology for estimating the effect of this project on wholesale electric energy prices and supply to Missouri.[1]

The PROMOD Model

PROMOD is an electric market simulation model marketed by ABB. PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load. This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load, and thus calculates Locational Marginal Prices ("LMPs") at individual nodes within the system. PROMOD and similar dispatch modeling programs are used to forecast electricity prices, understand transmission flows and constraints, and predict generation output. It can also perform and support various reliability analyses, including calculation of loss-of-load probability, expected unserved energy, and effective capacity support.

Data and Assumptions

The analysis of the Project relies on data developed by the Midcontinent Independent System Operator, Inc. ("MISO") in its MISO Transmission Expansion Planning ("MTEP") process. The MTEP process is undertaken in each year to, "…ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and

[1] The Missouri region analyzed captures all Missouri loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.

enable a competitive electricity market to benefit all customers."[2] As a part of this process, MISO performs detailed economic and engineering analyses of many alternative transmission projects using PROMOD, along with other engineering tools and analyses. MISO also undertakes analysis of certain projects previously approved, such as the Multi-Value Project ("MVP") Portfolio.

The analyses herein are based on the same data sets and analyses developed by MISO to perform its analysis for MTEP 2016 ("MTEP16"). The data and assumptions used by MISO in its MTEP16 analysis are based on ABB-provided data, and have been modified as needed by MISO. A detailed description of MISO's analysis, including data, assumptions and "futures" scenarios evaluated, is provided in the MTEP 2016 Report.[3] The PROMOD data includes:

1. load forecasts provided by individual load serving entities ("LSE") within MISO,[4]
2. transmission line data from transmission operators,[5]
3. unit specifications for existing generation resources,[6]
4. new generation resources based on units planned and under construction,[7]
5. future generation resource additions developed by a capacity expansion model,[8]
6. retirement of generation facilities based on currently announced retirements,[9]

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[2] MISO website, available at https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx, accessed on September 6, 2017.

[3] MISO, *MISO Transmission Expansion Plan*, September 13, 2016 (hereafter "MTEP 2016").

[4] Demand and energy growth rates for each region are provided in: MISO, *MISO Transmission Expansion Plan 2016: Appendix E2 EGEAS Assumptions Document*, at p. 17 ("MTEP16 Assumptions Document" hereafter).

[5] Transmission constraints are based on the then-most recent Book of Flowgates from MISO and North American Electric Reliability Corporation (NERC), updated to include rating and configuration changes from studies performed during the MTEP 11 process. Transmission line data includes items such as the voltage rating of the line and the buses that each line runs between.

[6] Individual unit specifications include maximum operating capacity; fuel type; variable costs; no-load and startup costs; minimum run times; emission rates; and heat rate curves.

[7] Detailed information on the existing, under construction and planned units in each region is provided in MTEP16 Assumptions Document, at p. 26

[8] MISO relies upon the Electric Generation Expansion Analysis System (EGEAS) model developed by the Electric Power Research Institute. EGEAS is designed to find the optimized capacity expansion plan to meet forecast demand (load plus planning reserve margin target minus losses) through a least cost-mix of supply-side and demand-side resources. Planning reserve margins are identified in MTEP16 Assumptions Document, at pp. 19-20.

[9]As part of MTEP 2016, MISO has performed a Clean Power Plan Regulation Impact Analysis that identifies planning needs arising from the retirement of coal-fired generation facilities due to EPA regulations and other

7. "hurdle rates" for transactions between NERC regions,[10] and
8. fuel and emission price forecasts.

The system modeled includes individual generator data and complete transmission information for the Eastern Interconnection,[11] at the bus[12] level. Thus, the model provides estimates of the loads, production decisions and wholesale market outcomes for the entirety of the state of Missouri, including the MISO, SPP and other systems. As modelled within PROMOD, Missouri is represented by eight "areas", which reflect aggregations of LSE service territories, including five areas that are solely within Missouri and three areas that span Missouri and adjacent states.

The quantity and location of future renewable resources, including wind and solar, reflect multiple factors. In the initial MVP Report analysis, future renewables resources were assumed to both meet state renewable energy requirements and reduce the combined cost of renewable and transmission resources.[13] In subsequent analyses, including MTEP16, these future resources have been adjusted to account for both new resources developed since the initial MVP Report and changes in the resource quantities needed to meet renewable energy requirements.[14] In MTEP16, to meet these state requirements, 5,000 to 10,400 MW of new renewable resources are added between 2015 and 2030 across the scenarios.[15] As described below, some scenarios assume

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market factors (*e.g.*, competition from natural gas-fired generation). See MTEP16 Assumptions Document, at p. 8 and MTEP 2016 pp. 161-165.

[10] PROMOD allows power to flow between regions based on economic transactions (subject to security constraints and congestion) such that prices must exceed generator costs in a neighboring region by a dollar per MWh "hurdle rate" in order for power to flow across regions.

[11] The Eastern Interconnection comprises roughly the eastern two-thirds of the "lower 48" (excluding portions of Texas), including the Canadian provinces east of Alberta and the following NERC regions: Midwest Reliability Organization (MRO), Southwest Power Pool (SPP), SERC Reliability Corporation (SERC), Reliability*First* Corporation (RFC), and Northeast Power Coordinating Council (NPCC). MISO's PROMOD modeling excludes Florida, New England, and Eastern Canada, but accounts for aggregate regional flows to and from these areas through the use of fixed transactions. For more detail, see MTEP16 Assumptions Document, at p. 19.

[12] A bus is the specific geographical point that a generator is located at or that a transmission line connects to.

[13] MISO determined the amount of wind enabled by the MVP portfolio by first determining the amount of wind needed to comply with state renewable energy requirements, and then determining what amount of wind would not be supported but for the MVP portfolio. This process is detailed by MISO in the MVP Report, at pp. 17-20 and 48-49.

[14] Because many state renewable energy requirements mandate that a specified fraction of electric energy consumed be supplied through eligible renewable resources, as future forecasts for energy load have changed, the quantity of future renewable energy needed to meet these requirements has changed, as well.

[15] MTEP16 Assumptions Document, Figure E2.10: Resource Additions and Retirements, at p 26.

additional future renewable resources incremental to those required to meet these existing state requirements.[16]

The Project would include transmission facilities that will be routed south from the Missouri-Iowa border to the proposed ATXI Zachary substation near Kirksville, Missouri, and then westerly on to the Maywood switching station near Palmyra, Missouri. I also understand that the Project would include 96 miles of new 345-kV transmission line, and a new 345-kV terminal and 345/161 kV step-down transformer at the new Zachary substation, which will connect to Ameren Missouri's existing Adair substation.

The Project includes nearly all of MVP 8 and the Missouri portion of MVP 7. MVP 7 and 8 are shown geographically in **Figure 1**. The analysis of the Project herein compares scenarios with and without MVP 7 and 8, which is an appropriate assumption because the Iowa portions of MVP 7 are not electrically interconnected with any other elements of the transmission system. All scenarios evaluated include all of the other MVPs in MISO's MVP portfolio – that is, MVPs 1 to 6, and 9 to 17.[17]

Apart from the presence of the Project itself, the only other difference between the "with Project" and "without Project" cases is the capacity of wind resources in service. In the "without Project" case, the quantity of new wind resources has been reduced because the transmission system cannot support all new MVP wind resources without introducing reliability risks. Unless new wind additions are reduced, power flows may exceed line capacities under certain contingencies. To determine the quantity of wind capacity that can be supported, MISO performs an analysis that identifies the minimum quantity of wind capacity reductions that allow line loading to be kept within limits.[18] **Table 1** reports the difference in dispatched wind power capacity

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[16] *See* MTEP 2016, at pp. 102-103.

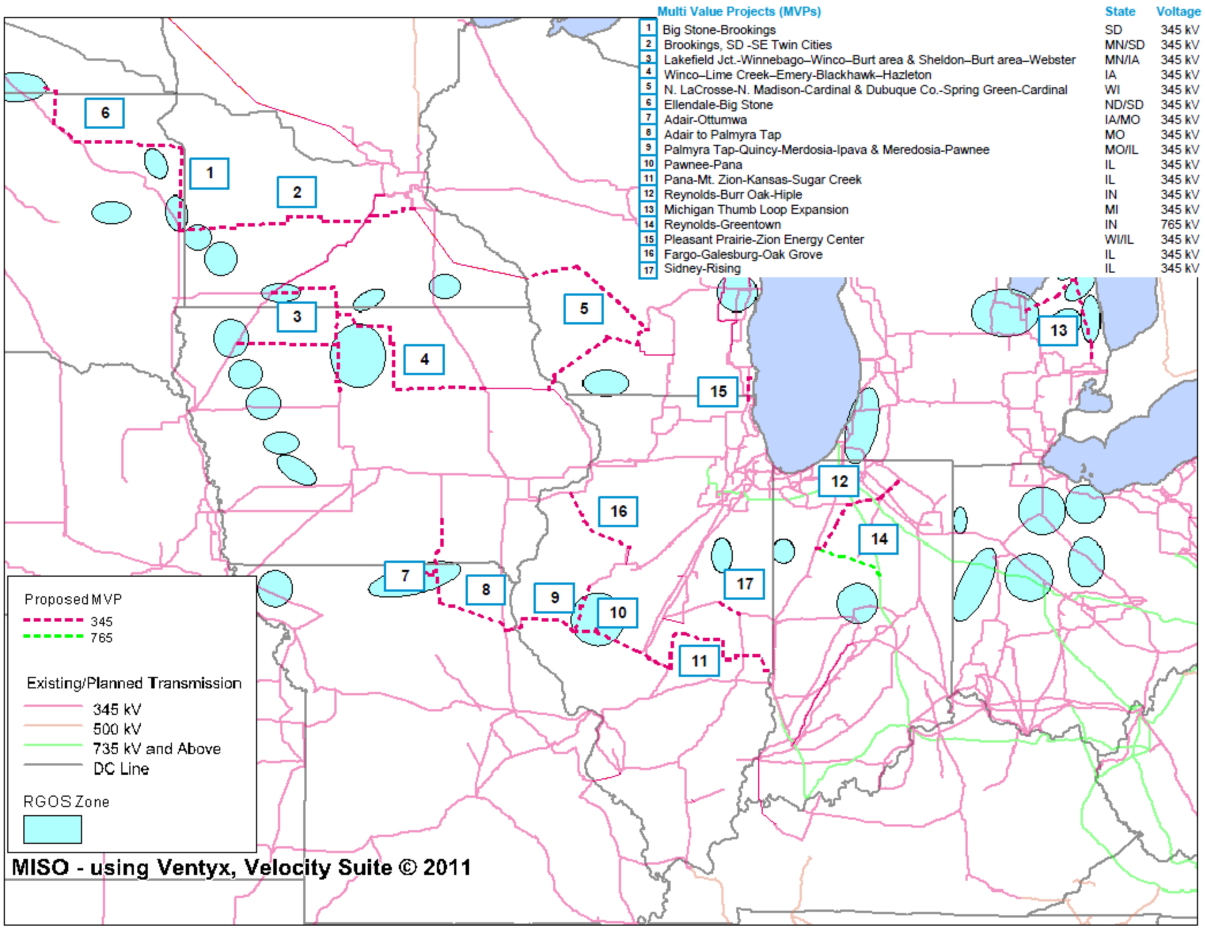
[17] These "other" MVPs are identified in Table 1.1 of MISO, *Multi Value Project Portfolio: Results and Analyses*, January 10, 2012 (hereafter "MVP Report").

[18] For further detail on this analysis, see MVP Report, at p. 48, MISO, "MTEP14 MVP Triennial Review," September 2014, at pp. 22-23 (hereafter, "MVP Triennial Update").

between the “with Project” and “without Project” cases for affected resources based on analysis by MISO.[19]

Figure 1

Map of MVP Portfolio



[19] Direct communication with MISO, August 16, 2017. The wind zones identified in Table 1 refer to wind zones defined by MISO through its wind siting strategy. For more detail, see MVP Report, at pp. 17-18.

SCHEDULE TS-02

Table 1

Reduction in New Wind Capacity in the "Without Project" Case

Wind Zone/Farm	State	2025 MW Reduction	2030 MW Reduction
Missouri (Zone A)	Missouri	134.3 - 354.0	134.3 - 354.0
Missouri (Zone C)	Missouri	188.7 - 292.2	188.7 - 292.2
Iowa (Zone H + I)	Iowa	63.6- 830.1	172.2 - 1,426.0
Adair	Iowa	174.5 - 175.0	175
Morning Light	Iowa	100.0	100
Eclipse Wind Farm	Iowa	200.0	200
Rippey Wind	Iowa	50.0 - 50.4	50.4
Farmers City	Missouri	146.0	146
Rolling Hills	Iowa	443.2 - 443.9	443.9
Walnut Wind	Iowa	153.0	153
Total		**1,654.0 - 2,744.6**	**1,762.2 - 3,340.5**

Note: Wind zones refer to particular wind farms/projects or generic wind zones developed within MISO's Regional Generation Outlet Study process (November 19, 2010). The particular reductions identified in Table 1 reflect an analysis that identifies the minimum quantity of resources that would need to be reduced to maintain reliable system operations. It does not account for any existing transmission agreements, nor does it reflect any regulatory determination affecting the ability of particular resources to flow power.

Analytical Method

Three sets of computations were performed in order to measure the effect of the Project: (i) a wholesale electric energy price comparison that evaluates changes in Missouri LMPs, (ii) a cost comparison that evaluates changes in production costs needed to meet load in both Missouri and MISO, and the net change in costs to Missouri from changes in both Missouri production costs and Missouri customers' share of construction costs, and (iii) an emissions comparison that evaluates changes in levels of four air emissions. The analytical methods used for these computations are described further below.

SCHEDULE TS-02

Wholesale Electric Energy Price Comparison

Computation of wholesale electric energy prices is based on two outputs from the PROMOD model: area LMPs and area load. The process used to develop Missouri wholesale energy prices, referred to as Missouri LMPs, is as follows:

1. Hourly area LMPs are calculated by PROMOD and reflect the load-weighted LMP of all nodes within the area.
2. Area load is based on the PROMOD inputs, which were developed by MISO based on hour-by-hour load forecasts from the underlying load-serving entities.[20]
3. The load-weighted average annual LMP is calculated for each area based on the hourly area LMPs and the hourly area loads.[21]
4. The load-weighted LMP for Missouri, or Missouri LMP, is calculated based on each Missouri area's LMP, calculated as described above in #3, weighted by the estimated load for each Missouri area, as described in #2. Some areas, as modeled in PROMOD, include loads in Missouri and one or more neighboring states. In this case, the (1) the load-weighted LMP for the Missouri portion of the area is assumed to be the load-weighted LMP for the entire multi-state area, and (2) the load for the Missouri portion of the area reflects the area's total load (in PROMOD) multiplied by the percent of the area's load that is in Missouri, which is developed using data from the Energy Information Administration.[22]

Cost Comparison

The process used to develop changes in Missouri Production Costs and MISO Production Costs is as follows:

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[20] These loads reflect forecasts for annual peak load and annual energy shaped over 8,760 hours.

[21] Hours in which the LMP for a Missouri area as calculated by PROMOD is less than -$10/MWh are set to an LMP of -$10/MWh. Hours in which the LMP for a Missouri area is greater than $1,000/MWh are capped at $1,000/MWh.

[22] See Form EIA-861 data files, available at http://www.eia.gov/electricity/data/eia861/index.html, accessed August 2017.

1. Production costs are calculated from PROMOD output for each hour of the year.
2. For Missouri Production costs, these costs reflect the hourly fuel, variable operations and maintenance, emission allowance, and start-up costs associated with supplying Missouri load, adjusted for net sales and purchases (imports or exports) of power with areas outside of Missouri, including areas within and outside of MISO. Missouri Production Costs for 2025 and 2030 are calculated as the sum of hourly production costs.
3. For MISO Production costs, these costs reflect the hourly fuel, variable operations and maintenance, emission allowance, and start-up costs associated with supplying MISO load, adjusted for net sales and purchases (imports or exports) of power with areas outside of MISO. MISO Production Costs for 2025 and 2030 are calculated as the sum of hourly production costs.

The process used to develop Missouri Net Costs from the Project is as follows:

1. The present value of total Missouri Production Costs is calculated for the 20-year period, 2020 to 2039, based on the annual Missouri Production Costs for 2025 and 2030. The year 2020 is chosen to start the flow of changes in production costs because this is the first full year in which all elements of the Project are in service.[23] Twenty years of payment reductions are calculated, consistent with the shorter of the two evaluation periods used in MISO's MVP economic analysis.[24] Costs over the period 2020 to 2039 are calculated through interpolation and extrapolation from the 2025 and 2030 results. Annual results are then discounted back to 2017 using both a 3.0 percent and 8.2 percent discount rate to account for a range of possible opportunity costs.[25]
2. The present value of Missouri Net Costs is calculated as the net of (1) total production costs (as calculated in #1) and (2) Missouri customers' portion of Project costs. Missouri customers' portion of Project costs reflects two components. The

[23] Testimony of ATXI witness Mr. James Jontry.

[24] MISO evaluates the MVP Portfolio over 20- and 40-year horizons. *See* MVP Report at p. 68.

[25] These discount rates are consistent with those used by MISO in its economic analysis. *See* MVP Report at p. 68, MVP Triennial Update, at p. 28.

SCHEDULE TS-02

first is capital costs for new transmission plant. For the purposes of the analysis, costs for new transmission plant are incurred in the year in which associated capital expenditures are made. These project costs are based on estimates developed by Ameren.[26] The second component is annual expenses. This cost is based on MISO's July 2017 Attachment O rate formula filing.[27] The portion of O&M and Taxes (other than income taxes) allocated to transmission in the formula rate is divided by transmission gross plant in service to calculate an annual transmission expense factor.[28] This factor is then applied to the Project capital cost to estimate ongoing annual expenses for the Project. All future costs are discounted back to 2017. As with all MVPs, transmission costs are then allocated to MISO customers based on their share of MWh load.[29] In the computations herein, MISO Missouri customers are assigned 7.6 percent of the total cost of the Project reflecting the MISO Missouri share of load in 2025, based on the projections in the MISO dataset.[30] Transmission payments for MISO Illinois customers total $38.4 million on a present value basis using a 3 percent discount rate and $30.0 million using an 8.2 percent discount rate.

These net benefits are conservative because they reflect only reduced production costs but do not include other possible reductions in costs such as those associated with potential reductions in capacity, operating reserve and other ancillary service requirements.[31] The estimate also does not account for other benefits to customers, such as improved reliability, the increased ability to meet renewable energy requirements, and emission reductions.

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[26] Direct Testimony of ATXI witness Mr. James Jontry.

[27] Attachment O to MISO Tariff filing, July 2017. Available at https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=259 , accessed August 2017.

[28] Transmission O&M charges are adjusted to exclude LSE Expenses, Account 565 expenses, FERC Annual Fees, and EPRI & associated expenditures as detailed in Ameren Missouri's Attachment O.

[29] MISO Tariff, Attachment MM, Multi-Value Project Charge.

[30] 7.6 percent is calculated as the MISO Missouri share of total MISO load based on the 2025 Business as Usual scenario.

[31] MVP Report, at pp. 50-65.

Emissions Comparison

The process used to develop changes in emissions is as follows:

1. MISO carbon dioxide (“CO_2”) emissions are calculated from PROMOD output. The estimated CO_2 quantities in each scenario reflects the sum of emissions from all generation sources within MISO, adjusted for the emissions of net imports and exports between MISO and areas outside of MISO. The emission intensity of imports and exports is assumed to equal the average emission intensity for all generation within MISO.
2. Missouri emissions of nitrogen oxides (“NO_x”), sulfur dioxide (“SO_2”) and mercury are calculated from PROMOD output. The reported quantities reflect the sum of emissions from all areas within Missouri. For areas that include portions of both Missouri and one or more neighboring states, Missouri emissions reflect total area emissions multiplied by the percent of each area’s load that is in Missouri.

Scenarios

The results presented in the body of this testimony reflect several scenarios, which are detailed below and in **Table 2**. Each scenario was designed by MISO in its MTEP 2016 analysis, and no additional changes have been made. Detailed scenario specifications are provided by MISO in its MTEP 2016 report.[32]

Assumptions common to all scenarios include:

- Current policies and trends in place at the time of futures development continue, unchanged, throughout the duration of the study period, including applicable EPA regulations governing electric power generation, transmission and distribution, and all current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates; and
- 12.6 GW of coal unit retire to capture the expected effects of environmental regulations on the coal fleet.

[32] MTEP 2016, at p. 98-100.

Assumptions specific to particular scenarios include:

- **Business As Usual**– Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted by MISO market participants.

- **Low Demand** – Captures the effects of reduced economic growth resulting in lower energy costs and medium-low gas prices. Additional, age-related retirements are captured using 60 years as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.

- **High Demand** – Same as the Low Demand scenario, except assumes medium-high gas prices and high demand and energy growth.
- **Regional Clean Power Plan** – focuses on several key items from a footprint-wide level that, in combination, result in significant carbon reductions over the course of the study period, and include:
  - 14 GW of additional coal unit retirements, coupled with a $25/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, to result in significant carbon emissions reduction by 2030;
  - Additional, age-related retirements using 60 years as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric;
  - Declining costs for solar and wind resources; and
  - Business-as-Usual demand and energy growth rates.
- **Sub-Regional Clean Power Plan -** focuses on several key items from a zonal or state level, which combine to result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include:
  - 20 GW of additional coal unit retirements, coupled with a $40/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, to result in a significant reduction in carbon emissions by 2030;
  - Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric;
  - Declining costs for solar and wind resources; and

- Business-as-Usual demand and energy growth rates.

Table 2

Scenario Assumptions[33]

Future Scenarios	2030 Renewable Penetration	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas Price[34]	Inflation Rate	Carbon Cost
Business As Usual	12 percent	0.65 percent	0.76 percent	BAU	2.5 percent	None
Low Demand	12 percent	0.11 percent	0.19 percent	BAU - 20 percent	2 percent	None
High Demand	12 percent	1.55 percent	1.61 percent	BAU + 20 percent	4 percent	None
Regional Clean Power Plan	16 percent	0.65 percent	0.76 percent	BAU + 20 percent	2.5 percent	$25/ton
Sub-Regional Clean Power Plan	26 percent	0.65 percent	0.76 percent	BAU + 20 percent	4 percent	$40/ton

[33] Table 2 is based on MTEP16 Assumptions Document, at p. 8 and MTEP 16, Table 5.2-2, at p. 103.

[34] Gas Prices escalate at the inflation rate.

Table 1
Change in Missouri LMP Due to the Mark Twain Project

Scenario	Year	Missouri LMP ($ per MWh) With Project [A]	Missouri LMP ($ per MWh) Without Project [B]	Missouri LMP ($ per MWh) Difference [C] = [A] - [B]	Percent Difference [D] = [C]/[B]
Business as Usual	2025	$44.42	$44.90	-$0.47	-1.05%
	2030	$51.77	$52.28	-$0.51	-0.98%
Low Demand	2025	$31.92	$32.20	-$0.28	-0.87%
	2030	$34.93	$35.25	-$0.32	-0.91%
High Demand	2025	$55.03	$55.40	-$0.37	-0.67%
	2030	$73.03	$73.56	-$0.53	-0.72%
Regional CPP	2025	$72.99	$73.63	-$0.64	-0.87%
	2030	$80.71	$81.58	-$0.87	-1.06%
Sub-Regional CPP	2025	$95.27	$95.80	-$0.53	-0.56%
	2030	$113.04	$113.82	-$0.78	-0.69%

Notes:
[1] Load weighted values reflect all Missouri loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.
[2] A negative value in column [C] indicates a reduction in LMP due to the Project.

Table 2
Change in Missouri Production Cost Due to the Mark Twain Project

Scenario	Year	Missouri Production Cost ($ millions)			
		With Project	Without Project	Difference	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual	2025	$2,324.5	$2,356.9	-$32.4	-1.37%
	2030	$2,775.3	$2,818.4	-$43.2	-1.53%
Low Demand	2025	$1,654.1	$1,667.5	-$13.5	-0.81%
	2030	$1,739.1	$1,751.5	-$12.4	-0.71%
High Demand	2025	$3,345.6	$3,392.7	-$47.1	-1.39%
	2030	$4,562.6	$4,624.4	-$61.8	-1.34%
Regional CPP	2025	$4,369.3	$4,421.5	-$52.2	-1.18%
	2030	$4,804.5	$4,869.9	-$65.4	-1.34%
Sub-Regional CPP	2025	$6,120.7	$6,203.7	-$82.9	-1.34%
	2030	$7,339.0	$7,441.5	-$102.5	-1.38%

Notes:
[1] Values reflect all production costs to meet Missouri customer loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.
[2] A negative value in column [C] indicates a reduction in production cost due to the Project.

Table 3
Change in MISO Production Cost Due to the Mark Twain Project

		MISO Production Cost ($ millions)			
Scenario	**Year**	**With Project**	**Without Project**	**Difference**	**Percent Difference**
		[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Business as Usual	2025	$12,813.6	$12,978.3	-$164.8	-1.27%
	2030	$14,822.9	$15,017.2	-$194.2	-1.29%
Low Demand	2025	$9,334.3	$9,439.5	-$105.2	-1.11%
	2030	$10,134.2	$10,254.6	-$120.4	-1.17%
High Demand	2025	$17,096.9	$17,303.3	-$206.4	-1.19%
	2030	$23,299.6	$23,606.9	-$307.2	-1.30%
Regional CPP	2025	$22,467.4	$22,696.7	-$229.3	-1.01%
	2030	$25,286.1	$25,518.9	-$232.8	-0.91%
Sub-Regional CPP	2025	$28,809.0	$29,092.5	-$283.4	-0.97%
	2030	$32,812.0	$33,076.5	-$264.5	-0.80%

Notes:
[1] Values reflect all production costs to meet the loads of customers within the MISO footprint.
[2] A negative value in column [C] indicates a reduction in production cost due to the Project.

SCHEDULE TS-03

Table 4
Missouri Net Cost Impact Due to the Mark Twain Project, NPV as of 2017

Scenario	Discount Rate 3%: Difference in Production Cost (PV, $ millions) [A]	Discount Rate 3%: MISO MO Share of Project Costs (PV, $ millions) [B]	Discount Rate 3%: Difference in Net Costs ($ millions) [C]=[A]+[B]	Discount Rate 3%: Ratio [D]= -[A]/[B]	Discount Rate 8.2%: Difference in Production Cost (PV, $ millions) [E]	Discount Rate 8.2%: MISO MO Share of Project Costs (PV, $ millions) [F]	Discount Rate 8.2%: Difference in Net Costs ($ millions) [G]=[E]+[F]	Discount Rate 8.2%: Ratio [H]=-[E]/[F]
Business as Usual	-$530.7	$35.2	-$495.5	15.1	-$285.2	$28.0	-$257.2	10.2
Low Demand	-$181.8	$35.2	-$146.6	5.2	-$109.8	$28.0	-$81.8	3.9
High Demand	-$764.1	$35.2	-$729.0	21.7	-$412.9	$28.0	-$385.0	14.8
Regional CPP	-$825.3	$35.2	-$790.2	23.5	-$452.7	$28.0	-$424.7	16.2
Sub-Regional CPP	-$1,301.5	$35.2	-$1,266.4	37.0	-$717.1	$28.0	-$689.1	25.6

Notes:

[1] Values reflect all production costs to meet Missouri customer loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri

[2] All values reflecting production cost savings and project costs over the period 2017 to 2039 are shown on an NPV basis as of 2017.

[3] A negative value in columns [A] or [E] indicates a reduction in production cost due to the Project. Difference in Adjusted Production Cost is calculated in detail in Exhibit X.7.

[4] MISO Missouri Share of Project Costs is the Missouri share of total MISO Load (7.9%) multiplied by the total PV of project costs, equal to $445m and $354m as of 2017 at discount rates of 3% and 8.2%, respectively.

SCHEDULE TS-03

Table 5 (Page 1)
Change in Missouri Production Cost Due to the Mark Twain Project
Business as Usual Scenario

Year	Production Cost: With Project ($ millions)	Production Cost: Without Project ($ millions)	Production Cost: Difference ($ millions)	Production Cost: Percent Difference	PV Factor (3%)	PV Factor (8.2%)	Difference in Missouri Production Cost ($ millions, PV as of 2017): PV (3%)	Difference in Missouri Production Cost ($ millions, PV as of 2017): PV (8.2%)
	[A]	[B]	[C]=[A]-[B]	[D]=[C]/[A]	[E]	[F]	[G]=[C]*[E]	[H]=[C]*[F]
2020	$1,783.5	$1,803.0	-$19.4	-1.1%	0.915	0.789	-$17.8	-$15.3
2021	$1,873.7	$1,895.3	-$21.6	-1.2%	0.888	0.730	-$19.2	-$15.8
2022	$1,963.8	$1,987.6	-$23.7	-1.2%	0.863	0.674	-$20.5	-$16.0
2023	$2,054.0	$2,079.9	-$25.9	-1.3%	0.837	0.623	-$21.7	-$16.1
2024	$2,144.2	$2,172.2	-$28.1	-1.3%	0.813	0.576	-$22.8	-$16.2
2025	$2,234.3	$2,264.5	-$30.2	-1.4%	0.789	0.532	-$23.9	-$16.1
2026	$2,324.5	$2,356.9	-$32.4	-1.4%	0.766	0.492	-$24.8	-$15.9
2027	$2,414.6	$2,449.2	-$34.6	-1.4%	0.744	0.455	-$25.7	-$15.7
2028	$2,504.8	$2,541.5	-$36.7	-1.5%	0.722	0.420	-$26.5	-$15.4
2029	$2,594.9	$2,633.8	-$38.9	-1.5%	0.701	0.388	-$27.3	-$15.1
2030	$2,685.1	$2,726.1	-$41.0	-1.5%	0.681	0.359	-$27.9	-$14.7
2031	$2,775.3	$2,818.4	-$43.2	-1.6%	0.661	0.332	-$28.6	-$14.3
2032	$2,865.4	$2,910.8	-$45.4	-1.6%	0.642	0.307	-$29.1	-$13.9
2033	$2,955.6	$3,003.1	-$47.5	-1.6%	0.623	0.283	-$29.6	-$13.5
2034	$3,045.7	$3,095.4	-$49.7	-1.6%	0.605	0.262	-$30.1	-$13.0
2035	$3,135.9	$3,187.7	-$51.8	-1.7%	0.587	0.242	-$30.4	-$12.5
2036	$3,226.0	$3,280.0	-$54.0	-1.7%	0.570	0.224	-$30.8	-$12.1
2037	$3,316.2	$3,372.4	-$56.2	-1.7%	0.554	0.207	-$31.1	-$11.6
2038	$3,406.4	$3,464.7	-$58.3	-1.7%	0.538	0.191	-$31.3	-$11.1
2039	$3,496.5	$3,557.0	-$60.5	-1.7%	0.522	0.177	-$31.6	-$10.7
Present Value of Missouri Production Cost ($ millions, PV as of 2017):							-$530.7	-$285.2

Notes:

[1] Values reflect all production costs to meet Missouri customer loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.

[2] A negative value in column [C] indicates a reduction in production cost due to the Project.

SCHEDULE TS-03

Table 5 (Page 2)
Change in Missouri Production Cost Due to the Mark Twain Project
Low Demand Scenario

	Production Cost						Difference in Missouri Production Cost ($ millions, PV as of 2017)	
Year	**With Project ($ millions)**	**Without Project ($ millions)**	**Difference ($ millions)**	**Percent Difference**	**PV Factor (3%)**	**PV Factor (8.2%)**	**PV (3%)**	**PV (8.2%)**
	[A]	**[B]**	**[C]=[A]-[B]**	**[D]=[C]/[A]**	**[E]**	**[F]**	**[G]=[C]*[E]**	**[H]=[C]*[F]**
2020	$1,552.0	$1,566.8	-$14.8	-1.0%	0.915	0.789	-$13.5	-$11.6
2021	$1,569.0	$1,583.6	-$14.5	-0.9%	0.888	0.730	-$12.9	-$10.6
2022	$1,586.0	$1,600.4	-$14.3	-0.9%	0.863	0.674	-$12.4	-$9.7
2023	$1,603.0	$1,617.2	-$14.1	-0.9%	0.837	0.623	-$11.8	-$8.8
2024	$1,620.0	$1,634.0	-$13.9	-0.9%	0.813	0.576	-$11.3	-$8.0
2025	$1,637.0	$1,650.8	-$13.7	-0.8%	0.789	0.532	-$10.8	-$7.3
2026	$1,654.1	$1,667.5	-$13.5	-0.8%	0.766	0.492	-$10.3	-$6.6
2027	$1,671.1	$1,684.3	-$13.3	-0.8%	0.744	0.455	-$9.9	-$6.0
2028	$1,688.1	$1,701.1	-$13.1	-0.8%	0.722	0.420	-$9.4	-$5.5
2029	$1,705.1	$1,717.9	-$12.9	-0.8%	0.701	0.388	-$9.0	-$5.0
2030	$1,722.1	$1,734.7	-$12.7	-0.7%	0.681	0.359	-$8.6	-$4.5
2031	$1,739.1	$1,751.5	-$12.4	-0.7%	0.661	0.332	-$8.2	-$4.1
2032	$1,756.1	$1,768.3	-$12.2	-0.7%	0.642	0.307	-$7.9	-$3.8
2033	$1,773.1	$1,785.1	-$12.0	-0.7%	0.623	0.283	-$7.5	-$3.4
2034	$1,790.1	$1,801.9	-$11.8	-0.7%	0.605	0.262	-$7.1	-$3.1
2035	$1,807.1	$1,818.7	-$11.6	-0.6%	0.587	0.242	-$6.8	-$2.8
2036	$1,824.1	$1,835.5	-$11.4	-0.6%	0.570	0.224	-$6.5	-$2.5
2037	$1,841.1	$1,852.3	-$11.2	-0.6%	0.554	0.207	-$6.2	-$2.3
2038	$1,858.1	$1,869.1	-$11.0	-0.6%	0.538	0.191	-$5.9	-$2.1
2039	$1,875.1	$1,885.9	-$10.8	-0.6%	0.522	0.177	-$5.6	-$1.9
			Present Value of Missouri Production Cost ($ millions, PV as of 2017):				-$181.8	-$109.8

Notes:

[1] Values reflect all production costs to meet Missouri customer loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.

[2] A negative value in column [C] indicates a reduction in production cost due to the Project.

SCHEDULE TS-03

Table 5 (Page 3)
Change in Missouri Production Cost Due to the Mark Twain Project
High Demand Scenario

Year	Production Cost: With Project ($ millions)	Production Cost: Without Project ($ millions)	Production Cost: Difference ($ millions)	Production Cost: Percent Difference	PV Factor (3%)	PV Factor (8.2%)	Difference in Missouri Production Cost ($ millions, PV as of 2017): PV (3%)	Difference in Missouri Production Cost ($ millions, PV as of 2017): PV (8.2%)
	[A]	[B]	[C]=[A]-[B]	[D]=[C]/[A]	[E]	[F]	[G]=[C]*[E]	[H]=[C]*[F]
2020	$1,885.2	$1,914.7	-$29.5	-1.6%	0.915	0.789	-$27.0	-$23.3
2021	$2,128.6	$2,161.0	-$32.4	-1.5%	0.888	0.730	-$28.8	-$23.7
2022	$2,372.0	$2,407.4	-$35.4	-1.5%	0.863	0.674	-$30.5	-$23.8
2023	$2,615.4	$2,653.7	-$38.3	-1.5%	0.837	0.623	-$32.1	-$23.9
2024	$2,858.8	$2,900.0	-$41.2	-1.4%	0.813	0.576	-$33.5	-$23.7
2025	$3,102.2	$3,146.4	-$44.2	-1.4%	0.789	0.532	-$34.9	-$23.5
2026	$3,345.6	$3,392.7	-$47.1	-1.4%	0.766	0.492	-$36.1	-$23.2
2027	$3,589.0	$3,639.0	-$50.0	-1.4%	0.744	0.455	-$37.2	-$22.7
2028	$3,832.4	$3,885.4	-$53.0	-1.4%	0.722	0.420	-$38.3	-$22.3
2029	$4,075.8	$4,131.7	-$55.9	-1.4%	0.701	0.388	-$39.2	-$21.7
2030	$4,319.2	$4,378.0	-$58.8	-1.4%	0.681	0.359	-$40.1	-$21.1
2031	$4,562.6	$4,624.4	-$61.8	-1.4%	0.661	0.332	-$40.8	-$20.5
2032	$4,806.0	$4,870.7	-$64.7	-1.3%	0.642	0.307	-$41.5	-$19.8
2033	$5,049.4	$5,117.0	-$67.6	-1.3%	0.623	0.283	-$42.1	-$19.2
2034	$5,292.8	$5,363.4	-$70.5	-1.3%	0.605	0.262	-$42.7	-$18.5
2035	$5,536.2	$5,609.7	-$73.5	-1.3%	0.587	0.242	-$43.2	-$17.8
2036	$5,779.6	$5,856.0	-$76.4	-1.3%	0.570	0.224	-$43.6	-$17.1
2037	$6,023.0	$6,102.3	-$79.3	-1.3%	0.554	0.207	-$43.9	-$16.4
2038	$6,266.4	$6,348.7	-$82.3	-1.3%	0.538	0.191	-$44.2	-$15.7
2039	$6,509.8	$6,595.0	-$85.2	-1.3%	0.522	0.177	-$44.5	-$15.0
Present Value of Missouri Production Cost ($ millions, PV as of 2017):							-$764.1	-$412.9

Notes:

[1] Values reflect all production costs to meet Missouri customer loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.

[2] A negative value in column [C] indicates a reduction in production cost due to the Project.

SCHEDULE TS-03

Table 5 (Page 4)
Change in Missouri Production Cost Due to the Mark Twain Project
Regional Clean Power Plan Scenario

	Production Cost						Difference in Missouri Production Cost ($ millions, PV as of 2017)	
Year	With Project ($ millions)	Without Project ($ millions)	Difference ($ millions)	Percent Difference	PV Factor (3%)	PV Factor (8.2%)	PV (3%)	PV (8.2%)
	[A]	[B]	[C]=[A]-[B]	[D]=[C]/[A]	[E]	[F]	[G]=[C]*[E]	[H]=[C]*[F]
2020	$3,847.2	$3,883.5	-$36.3	-0.9%	0.915	0.789	-$33.3	-$28.7
2021	$3,934.2	$3,973.2	-$39.0	-1.0%	0.888	0.730	-$34.6	-$28.4
2022	$4,021.2	$4,062.8	-$41.6	-1.0%	0.863	0.674	-$35.9	-$28.1
2023	$4,108.3	$4,152.5	-$44.3	-1.1%	0.837	0.623	-$37.1	-$27.6
2024	$4,195.3	$4,242.2	-$46.9	-1.1%	0.813	0.576	-$38.1	-$27.0
2025	$4,282.3	$4,331.9	-$49.6	-1.2%	0.789	0.532	-$39.1	-$26.4
2026	$4,369.3	$4,421.5	-$52.2	-1.2%	0.766	0.492	-$40.0	-$25.7
2027	$4,456.4	$4,511.2	-$54.8	-1.2%	0.744	0.455	-$40.8	-$24.9
2028	$4,543.4	$4,600.9	-$57.5	-1.3%	0.722	0.420	-$41.5	-$24.2
2029	$4,630.4	$4,690.6	-$60.1	-1.3%	0.701	0.388	-$42.2	-$23.3
2030	$4,717.5	$4,780.2	-$62.8	-1.3%	0.681	0.359	-$42.7	-$22.5
2031	$4,804.5	$4,869.9	-$65.4	-1.4%	0.661	0.332	-$43.2	-$21.7
2032	$4,891.5	$4,959.6	-$68.0	-1.4%	0.642	0.307	-$43.7	-$20.9
2033	$4,978.6	$5,049.2	-$70.7	-1.4%	0.623	0.283	-$44.0	-$20.0
2034	$5,065.6	$5,138.9	-$73.3	-1.4%	0.605	0.262	-$44.4	-$19.2
2035	$5,152.6	$5,228.6	-$76.0	-1.5%	0.587	0.242	-$44.6	-$18.4
2036	$5,239.7	$5,318.3	-$78.6	-1.5%	0.570	0.224	-$44.8	-$17.6
2037	$5,326.7	$5,407.9	-$81.2	-1.5%	0.554	0.207	-$45.0	-$16.8
2038	$5,413.7	$5,497.6	-$83.9	-1.5%	0.538	0.191	-$45.1	-$16.0
2039	$5,500.8	$5,587.3	-$86.5	-1.6%	0.522	0.177	-$45.2	-$15.3
			Present Value of Missouri Production Cost ($ millions, PV as of 2017):				-$825.3	-$452.7

Notes:
[1] Values reflect all production costs to meet Missouri customer loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.
[2] A negative value in column [C] indicates a reduction in production cost due to the Project.

SCHEDULE TS-03

Table 5 (Page 5)
Change in Missouri Production Cost Due to the Mark Twain Project
Sub-Regional Clean Power Plan Scenario

Year	Production Cost: With Project ($ millions)	Production Cost: Without Project ($ millions)	Production Cost: Difference ($ millions)	Production Cost: Percent Difference	PV Factor (3%)	PV Factor (8.2%)	Difference in Missouri Production Cost ($ millions, PV as of 2017): PV (3%)	Difference in Missouri Production Cost ($ millions, PV as of 2017): PV (8.2%)
	[A]	[B]	[C]=[A]-[B]	[D]=[C]/[A]	[E]	[F]	[G]=[C]*[E]	[H]=[C]*[F]
2020	$4,658.8	$4,718.2	-$59.5	-1.3%	0.915	0.789	-$54.4	-$46.9
2021	$4,902.4	$4,965.8	-$63.4	-1.3%	0.888	0.730	-$56.3	-$46.2
2022	$5,146.1	$5,213.4	-$67.3	-1.3%	0.863	0.674	-$58.0	-$45.4
2023	$5,389.8	$5,461.0	-$71.2	-1.3%	0.837	0.623	-$59.6	-$44.4
2024	$5,633.4	$5,708.5	-$75.1	-1.3%	0.813	0.576	-$61.1	-$43.3
2025	$5,877.1	$5,956.1	-$79.0	-1.3%	0.789	0.532	-$62.4	-$42.1
2026	$6,120.7	$6,203.7	-$82.9	-1.4%	0.766	0.492	-$63.6	-$40.8
2027	$6,364.4	$6,451.3	-$86.9	-1.4%	0.744	0.455	-$64.6	-$39.5
2028	$6,608.1	$6,698.8	-$90.8	-1.4%	0.722	0.420	-$65.6	-$38.1
2029	$6,851.7	$6,946.4	-$94.7	-1.4%	0.701	0.388	-$66.4	-$36.8
2030	$7,095.4	$7,194.0	-$98.6	-1.4%	0.681	0.359	-$67.1	-$35.4
2031	$7,339.0	$7,441.5	-$102.5	-1.4%	0.661	0.332	-$67.8	-$34.0
2032	$7,582.7	$7,689.1	-$106.4	-1.4%	0.642	0.307	-$68.3	-$32.6
2033	$7,826.4	$7,936.7	-$110.3	-1.4%	0.623	0.283	-$68.8	-$31.3
2034	$8,070.0	$8,184.3	-$114.2	-1.4%	0.605	0.262	-$69.1	-$29.9
2035	$8,313.7	$8,431.8	-$118.2	-1.4%	0.587	0.242	-$69.4	-$28.6
2036	$8,557.3	$8,679.4	-$122.1	-1.4%	0.570	0.224	-$69.6	-$27.3
2037	$8,801.0	$8,927.0	-$126.0	-1.4%	0.554	0.207	-$69.8	-$26.0
2038	$9,044.6	$9,174.5	-$129.9	-1.4%	0.538	0.191	-$69.8	-$24.8
2039	$9,288.3	$9,422.1	-$133.8	-1.4%	0.522	0.177	-$69.8	-$23.6
Present Value of Missouri Production Cost ($ millions, PV as of 2017):							-$1,301.5	-$717.1

Notes:
[1] Values reflect all production costs to meet Missouri customer loads, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.
[2] A negative value in column [C] indicates a reduction in production cost due to the Project.

SCHEDULE TS-03

Table 6
Change in MISO CO_2 Emissions Due to the Mark Twain Project

		MISO CO_2 Emissions (tons)			
Scenario	**Year**	**With Project**	**Without Project**	**Difference**	**Percent Difference**
		[A]	**[B]**	**[C] = [A] - [B]**	**[D] = [C]/[B]**
Business as Usual	2025	335,025,504	338,651,499	-3,625,995	-1.07%
	2030	337,171,359	340,899,045	-3,727,686	-1.09%
Low Demand	2025	315,087,006	318,617,479	-3,530,473	-1.11%
	2030	304,138,371	307,908,160	-3,769,789	-1.22%
High Demand	2025	365,526,457	368,463,164	-2,936,707	-0.80%
	2030	379,286,502	382,561,341	-3,274,839	-0.86%
Regional CPP	2025	291,737,392	293,884,262	-2,146,869	-0.73%
	2030	283,750,124	286,011,862	-2,261,739	-0.79%
Sub-Regional CPP	2025	231,680,023	233,835,779	-2,155,756	-0.92%
	2030	216,878,791	218,646,868	-1,768,077	-0.81%

Notes:
[1] Emission values are adjusted for net imports into the region.
[2] A negative value in column [C] indicates a reduction in CO_2 emissions due to the Project.

Table 7
Change in Missouri NO_x Emissions Due to the Mark Twain Project

Scenario	Year	Missouri NO_x Emissions (lbs) With Project	Without Project	Difference	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual	2025	127,296,593	127,904,219	-607,626	-0.48%
	2030	128,579,468	129,147,197	-567,729	-0.44%
Low Demand	2025	124,409,312	125,059,125	-649,813	-0.52%
	2030	123,906,234	124,613,136	-706,902	-0.57%
High Demand	2025	128,650,138	128,935,648	-285,510	-0.22%
	2030	130,189,484	130,415,200	-225,716	-0.17%
Regional CPP	2025	54,415,025	54,644,230	-229,205	-0.42%
	2030	53,779,348	54,157,785	-378,437	-0.70%
Sub-Regional CPP	2025	43,083,585	43,351,209	-267,624	-0.62%
	2030	41,781,498	41,976,420	-194,922	-0.46%

Notes:
[1] Values reflect all emissions from Missouri companies, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.
[2] A negative value in column [C] indicates a reduction in mercury emissions due to the Project.

SCHEDULE TS-03

Table 8
Change in Missouri SO_2 Emissions Due to the Mark Twain Project

Scenario	Year	Missouri SO_2 Emissions (lbs)			Percent
		With Project	Without Project	Difference	Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual	2025	225,189,447	226,453,905	-1,264,458	-0.56%
	2030	225,521,730	226,853,648	-1,331,918	-0.59%
Low Demand	2025	221,230,684	222,753,627	-1,522,943	-0.68%
	2030	220,837,415	222,504,634	-1,667,219	-0.75%
High Demand	2025	230,860,174	231,568,586	-708,412	-0.31%
	2030	232,352,182	233,040,017	-687,835	-0.30%
Regional CPP	2025	138,114,055	138,699,827	-585,773	-0.42%
	2030	138,912,409	139,981,741	-1,069,332	-0.76%
Sub-Regional CPP	2025	92,631,726	92,999,618	-367,892	-0.40%
	2030	91,864,700	92,154,320	-289,621	-0.31%

Notes:
[1] Values reflect all emissions from Missouri companies, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.
[2] A negative value in column [C] indicates a reduction in mercury emissions due to the Project.

SCHEDULE TS-03

Table 9
Change in Missouri Mercury Emissions Due to the Mark Twain Project

Scenario	Year	Missouri Mercury Emissions (lbs) With Project	Without Project	Difference	Percent Difference
		[A]	[B]	[C] = [A] - [B]	[D] = [C]/[B]
Business as Usual	2025	2,122	2,133	-12	-0.55%
	2030	2,129	2,141	-12	-0.55%
Low Demand	2025	2,076	2,089	-14	-0.65%
	2030	2,074	2,089	-15	-0.72%
High Demand	2025	2,154	2,160	-6	-0.28%
	2030	2,162	2,168	-5	-0.24%
Regional CPP	2025	1,364	1,370	-6	-0.42%
	2030	1,350	1,362	-11	-0.84%
Sub-Regional CPP	2025	1,015	1,024	-9	-0.88%
	2030	985	997	-12	-1.18%

Notes:
[1] Values reflect all emissions from Missouri companies, including the Missouri portions of companies that span multiple states, as determined by the proportion of retail sales in Missouri.
[2] A negative value in column [C] indicates a reduction in mercury emissions due to the Project.

SCHEDULE TS-03