PROMOD Modeling and Data

This exhibit provides a summary of the PROMOD IV ("PROMOD") model, data and assumptions used in analyzing the Illinois Rivers Project, and the methodology for estimating the effect of the project on wholesale electric energy prices and supply to the MISO Illinois region.

The PROMOD Model

PROMOD is an electric market simulation model marketed by Ventyx. 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 Illinois Rivers Project relies on data developed by the Midwest ISO ("MISO") in its Multi Value Project ("MVP") process. A detailed description of MISO's MVP process and data analysis is provided in the MVP Report.[1] The principal purpose of the MVP projects are, as described by MISO, "to meet one or more of three goals: reliably and economically enable regional public policy needs; provide multiple types of economic value; and provide a combination of regional reliability and economic value."[2] To identify these transmission projects, MISO has performed detailed economic and engineering analyses of many alternative transmission projects and portfolios using PROMOD. The analyses herein are based on the same data sets and analyses developed by MISO to perform its analysis.

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

[2] MISO website, available at https://www.midwestiso.org/Planning/Pages/MVPAnalysis.aspx, accessed November 6, 2012.

The data and assumptions used by MISO in its MVP analysis are based on Ventyx-provided data, and have been modified as needed by MISO. This data includes:

1. load forecasts provided by individual utilities within MISO,[3]
2. transmission line data from transmission operators,[4]
3. unit specifications for existing generation resources,[5]
4. new generation resources based on units planned and under construction,[6]
5. future generation resource additions developed by a capacity expansion model,[7]
6. retirement of generation facilities based on currently announced retirements, but not in response to economic or regulatory factors, including EPA regulation,[8]
7. "hurdle rates" for transactions between NERC regions,[9] and
8. fuel and emission price forecasts.

The system modeled includes individual generator data and complete transmission information for the Eastern Interconnection,[10] at the bus[11] level.

[3] Demand and energy growth rates for each region are provided in: MISO, *MISO Transmission Expansion Plan 2011: PROMOD Case Assumptions Document*, p 23 ("MTEP PROMOD Assumptions" hereafter).

[4] Transmission constraints are based on the 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.

[5] 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.

[6] Detailed information on the existing, under construction and planned units in each region is provided in MTEP PROMOD Assumptions, p 17.

[7] 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 MTEP PROMOD Assumptions, pp 23-24.

[8] As part of MTEP 2011, MISO has performed an EPA Regulation Impact Analysis that identifies planning needs arising from the retirement of coal-fired generation facilities due to EPA regulations and other market factors (*e.g.*, competition from natural gas-fired generation). MISO's MVP analysis does not incorporate any retirements of coal-fired generation, aside from already announced retirements.

[9] 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.

[10] 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), Florida Reliability Coordinating Council (FRCC), Reliability*First* Corporation (RFC), and Northeast Power Coordinating Council (NPCC). MISO's PROMOD modeling excludes Peninsular Florida, New England, and Eastern Canada, but

The quantity and location of future renewable resources, including wind and solar, are determined by MISO both to meet state RPS requirements and reduce the combined cost of renewable and transmission resources.[12] Based on these requirements, MISO's analysis assumes that 8,765 MW of new wind resources are added in 2021, and an additional 2,272 MW of new wind resources are added by 2026.[13]

The Illinois Rivers Project includes four projects within the MVP portfolio.[14] These projects are listed in Table 1, and are shown geographically in Figure 1. The analysis herein compares scenarios with and without the Illinois Rivers Project transmission elements. Both scenarios include all of MISO's other (*i.e.*, non-Illinois Rivers Project) MVP projects.[15] Apart from the presence of the Illinois Rivers Project itself, the only other difference between the "with Illinois Rivers Project" and "without Illinois Rivers Project" cases is the capacity of wind resources in service. In the "without Illinois Rivers 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 curtailments that allow line loading to be kept within limits.[16] Table 2 reports the difference in new wind power capacity between the "with Illinois Rivers Project" and "without Illinois Rivers Project" cases based on analysis by MISO.[17]

accounts for aggregate regional flows to and from these areas through the use of fixed transactions. For more detail, see MTEP PROMOD Assumptions, p 24.

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

[12] MISO determined the amount of wind enabled by the MVP portfolio by first determining the amount of wind needed to meet RPS targets, 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, pp 17-20 and 48-49.

[13] Table 4.2, MVP Report. MISO also finds that the MVP portfolio can support an additional 2,230 MW of additional wind power from the wind zones without incurring additional reliability constraints. MVP Report, pp 48-49.

[14] These four are: (1) Palmyra Tap–Quincy–Meredosia–Ipava & Meredosia–Pawnee; (2) Pawnee–Pana; (3) Pana–Mt. Zion–Kansas–Sugar Creek; and (4) Sidney–Rising.

[15] These "other" MVPs are identified in Table 1.1 of the MVP Report.

[16] For further detail on this analysis, see MVP Report at p 48.

[17] Direct communication with MISO, October 18, 2012. 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.

Table 1
Illinois Rivers Project Elements

MVP Element	Project	Voltage	In-Service Year
9	Palmyra Tap–Quincy–Meredosia–Ipava &Meredosia–Pawnee	345	2016/17
10	Pawnee–Pana	345	2018
11	Pana–Mt. Zion–Kansas–Sugar Creek	345	2018/19
17	Sidney–Rising	345	2016

Figure 1
Map of MVP Portfolio

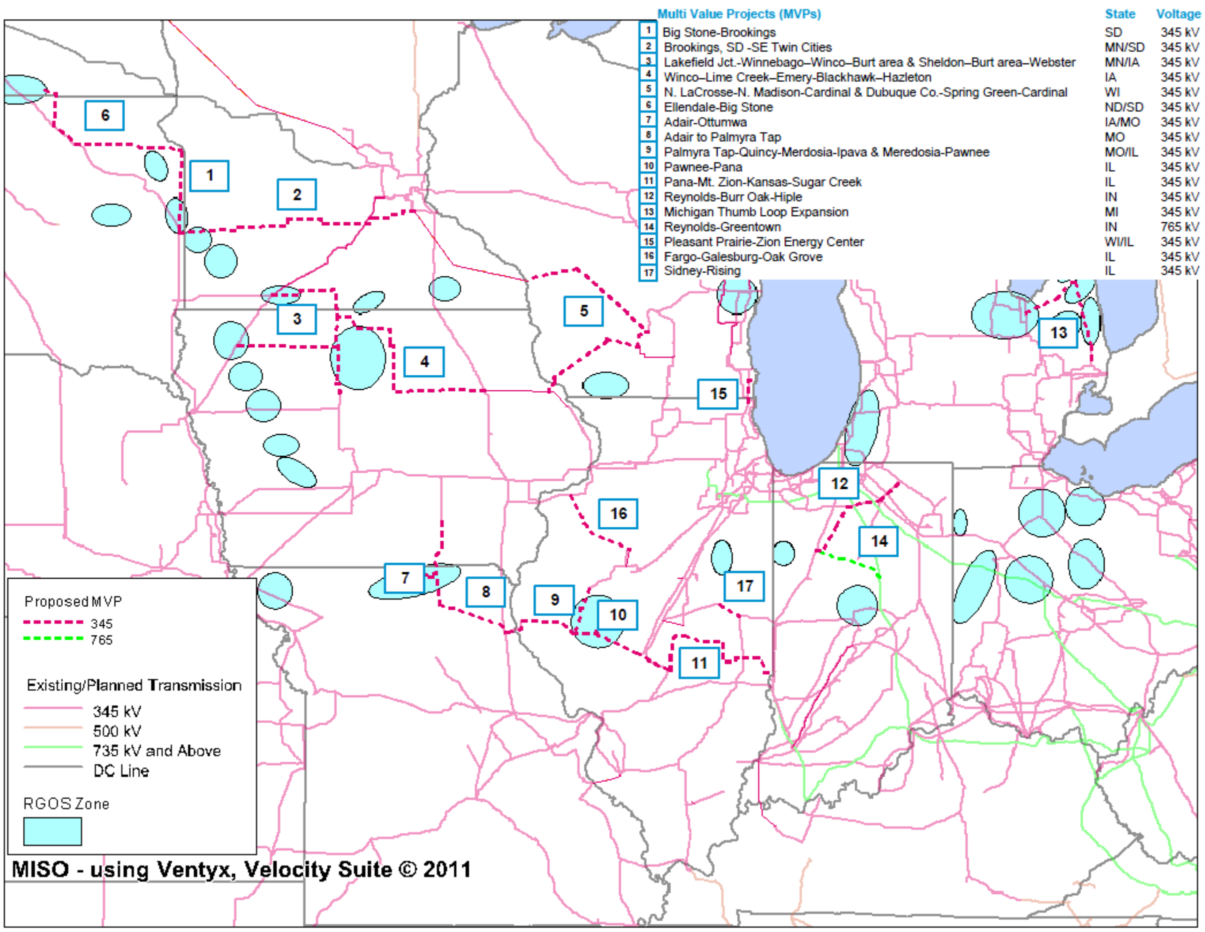

Table 2

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

Wind Zone	MW Reduction
Illnois (Zone F)	112
Illinois (Zone K)	402
Missouri (Zone C)	450
Wisconsin (Zone B)	211
White Oak	43
Total	1,218

Note: Zones refer to wind zones within each state, identified as a part of MISO's MVP process.

Analytical Method

Two computations were performed, (i) a wholesale electric energy price comparison that evaluates the changes in LMPs and accompanying customer payments as a result of the Illinois Rivers Project, and (ii) a Delivered Price Test ("DPT"), which determines changes in Economic Capacity[18] available to serve the MISO Illinois region as a result of the Illinois Rivers Project, both from within the MISO Illinois region and via imports. The analytical method used for these two computations is described further below.

Wholesale Electric Energy Price and Payment Comparison

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

1. Area LMPs are calculated by PROMOD and reflect the load-weighted LMP of all nodes within the area. Results are first presented which show the LMP differences across the MISO Illinois region[19] between the "with Illinois Rivers Project" and "without Illinois Rivers Project".

[18] Economic Capacity is a term used by the Federal Energy Regulatory Commission in competitive analyses to refer to generation capacity that is located within, or can be delivered into, a market area at a delivered cost that is no greater than 1.05 times the competitive price in the market.

[19] The MISO Illinois region is comprised of Ameren Illinois, the Springfield, Illinois City Water Light & Power (CWLP) system and Southern Illinois Power Company.

2. Area load is based on the PROMOD inputs used by MISO, and reflects hour-by-hour load forecasts for individual areas within MISO.[20] The hourly area load is multiplied by the hourly LMP to calculate the hourly cost of wholesale electric energy for each area. The cost of wholesale electric energy for 2021 and 2026 is calculated by summing hourly costs across all 8,760 hours in the year and across the three areas in MISO Illinois.
3. An adjustment to the hourly wholesale energy payments is made for CWLP and SIPC. Because CWLP is a municipal utility and SIPC is an electric cooperative, any changes in profits (revenues minus costs) to generation facilities owned by CWLP and SIPC can be used to reduce the rates charged to CWLP and SIPC customers. Consequently, in each scenario, the profits earned by CWLP and SIPC's generators are subtracted from the LMP-based payments for wholesale energy to arrive at a net payment.
4. Using these cost estimates for 2021 and 2026, changes in net payments are estimated for a 20-year period starting in 2020. The year 2020 is chosen to start the flow of changes in wholesale electric energy payments, because this is the first full year in which all elements of the Illinois Rivers Project are in service.[21] Twenty years of payment reductions are calculated, consistent with the shorter of the two evaluation periods used in MISO's MVP economic analysis.[22] Payment changes over the period 2020 to 2039 are calculated through interpolation and extrapolation from the 2021 and 2026 results. Annual results are then discounted back to 2013 using both a 3.0 percent and 8.2 percent discount rate to account for a range of possible opportunity costs.[23]
5. The net change in payments from the Illinois Rivers Project also reflects presumed transmission payments by MISO Illinois customers to support the cost of the Illinois Rivers Project. These costs reflect two components. The first is capital costs for new

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

[21] Estimated in-service data for the four elements of the Illinois Rivers Project are: (1) 2016/2017 for Palmyra Tap–Quincy–Meredosia–Ipava & Meredosia–Pawnee; (2) 2018 for Pawnee–Pana; (3) 2018/2019 for Pana–Mt. Zion–Kansas–Sugar Creek; and (4) 2016 for Sidney–Rising. *See* Table 1.1 of the MVP Report.

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

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

transmission plant. Consumers are assumed to begin paying for each element of the Illinois Rivers Project at the individual element's in-service data. These costs of the project are based on Ameren estimates as detailed in the testimony of other ATXI witnesses. The second component is annual expenses. This cost is based on Ameren Illinois Company's October 2012 Attachment O rate formula filing.[24] 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.[25] This factor is then applied to the Illinois Rivers Project capital cost to estimate ongoing annual expenses. The cost of the 2012 capital cost elements is inflated to 2013. All future costs are discounted back to 2013. Two sets of inflation/discount rates are used: 1.74 percent inflation with a 3 percent discount rate, and 2.91 percent inflation with an 8.2 percent discount rate. As with all MVPs, transmission costs are then allocated to MISO customers based on their share of MWh load.[26] In the computations herein, MISO Illinois customers are assigned 9.5 percent of the total cost of the Illinois Rivers Project.[27] Transmission payments for MISO Illinois customers total $155 million on a present value basis using a 3 percent discount rate and $120 million using an 8.2 percent discount rate.

These net benefits are conservative, because they reflect only reduced wholesale electric energy payments and not also other possible payment reductions such as those relating to capacity cost, operating reserves, planning reserve margins, and transmission line losses.[28] The estimate also does not account for other benefits to customers, such as improved reliability and the increased ability to meet RPS requirements.

[24] Ameren Illinois Company, Attachment O to MISO Tariff filing, October 2012. Available at https://www.midwestiso.org/Library/Pages/ManagedFileSet.aspx?SetId=259, accessed November 5, 2012.

[25] Transmission O&M charges are adjusted to exclude LSE Expenses and Account 565 expenses as detailed in Ameren Illinois Company's Attachment O.

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

[27] 9.5 percent is calculated as the MISO Illinois share of total MISO load based on the 2021 Business as Usual: Low Demand scenario.

[28] MVP Report, pp. 50-65.

Delivered Price Test

There are two components measured by the DPT for the MISO Illinois region: (1) Economic Capacity within the MISO Illinois region and (2) Economic Capacity from outside the MISO Illinois region that can be imported into it.

Economic Capacity within MISO Illinois

The first step is to develop Reference Prices for each scenario based on the results from the PROMOD runs. Reference Prices are developed for each of the following three periods.

a. *Summer Extreme Peak.* 1 percent highest load summer on-peak hours, where summer on-peak hours include June to August, M-F, 6am to 10pm CT, excluding NERC holidays.

b. *Summer Peak.* Summer on-peak hours, excluding Summer Extreme Peak hours. Summer on-peak hours include June to August, M-F, 6am to 10pm CT, excluding NERC holidays.

c. *Off-peak*. Off-peak hours, where off-peak hours include 24 hours on Saturday, Sunday and NERC holidays, and 8 hours (10pm to 6am CT) M-F (excluding NERC holidays).

The second step is to determine the Economic Capacity within the region, which is the capacity (MW) of generator units located in MISO Illinois that have a production cost less than or equal to 1.05 times the Reference Price as defined above. Production costs reflect each unit's average production cost at full capacity. Available capacity is calculated as the unit's full capacity less an average forced outage rate (applied during all seasons) and planned outage rate (applied only during non-summer months). Outage data is based on PROMOD inputs that are used by MISO.[29] Wind unit capacity in the MISO Illinois region was provided by MISO for each scenario, and is derated based on zonal wind capacity factors.[30]

[29] Forced and planned outages are provided by Ventyx in the PROMOD data, and reflect Generating Availability Data System (GADS) data from the North American Electric Reliability Corporation (NERC).

[30] Direct communication with MISO, November 5, 2012. Capacity factors used reflect an average of the IL-F and IL-K capacity factors reported by MISO. See Appendix B to the MVP Report, p 6.

Economic Capacity outside MISO Illinois

Economic Capacity from outside MISO Illinois is based on imports into MISO Illinois as determined by the PROMOD analysis. Hourly imports are calculated as the sum of gross positive inflows into the MISO Illinois region over transmission lines.[31] Economic Capacity is measured by the average imports into MISO Illinois during the 10 percent highest import hours.

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 MVP portfolio analysis, and no additional changes have been made. The definitions are provided by MISO in its MVP portfolio analysis report.[32]

- **Business As Usual: Low Demand –** assumes that current energy policies will be continued, with continuing recession level low demand and energy growth projections.[33]
- **Business As Usual: High Demand –** assumes that current energy policies will be continued, with demand and energy returning to pre-recession growth rates.[34]
- **Combined Energy Policy** – assumes multiple energy policies are enacted, including a 20 percent federal RPS, a carbon cap modeled on the Waxman-Markey Bill, implementation of a smart grid and widespread adoption of electric vehicles.
- **Carbon Constrained –** assumes that current energy policies will be continued, with the addition of a carbon cap modeled on the Waxman-Markey Bill.
- **Business As Usual: Low Demand High Gas –** same as the Low Demand scenarios listed above, except with higher gas prices (gas prices in 2011 were increased from $5 to $8/MMBtu).

[31] Negative flows (that is, exports from MISO Illinois) therefore are not reflected in this calculation.

[32] MVP Report, p 52.

[33] Note that the MVP Report titles this case "Business As Usual with Continued Low Demand and Energy Growth (BAULDE)."

[34] Note that the MVP Report titles this case "Business As Usual with Historic Demand and Energy Growth (BAUHDE)."

- **Business As Usual: High Demand High Gas –** same as the High Demand scenarios listed above, except with higher gas prices (gas prices in 2011 were increased from $5 to $8/MMBtu).

Table 2
Scenario Assumptions[35]

Future Scenarios	Wind Penetration	Effective Demand Growth Rate	Effective Energy Growth Rate	Gas Price	Carbon Cost / Reduction Target
Business As Usual: Low Demand	State RPS	0.78 percent	0.79 percent	BAU	None
Business As Usual: High Demand	State RPS	1.28 percent	1.42 percent	BAU	None
Combined Energy Policy	20 percent Federal RPS by 2025	0.52 percent	0.68 percent	BAU + $3	$50/ton (42 percent by 2033)
Carbon Constrained	State RPS	0.03 percent	0.05 percent	BAU + $3	$50/ton (42 percent by 2033)
Business As Usual: Low Demand, Hi Gas	State RPS	0.78 percent	0.79 percent	BAU + $3	None
Business As Usual: High Demand, Hi Gas	State RPS	1.28 percent	1.42 percent	BAU + $3	None

[35] Table 2 is based on Table 8.1 from the MVP Report.