4. Existing Supply-side Resources

Highlights

- *Ameren Missouri currently owns and operates 10,231 MW of supply-side resources: 5,114 MW of coal, 1,190 MW of nuclear, 3,091MW of natural gas/oil, and 836 MW of renewables and storage.*
- *Ameren Missouri Meramec Energy Center Units 1 & 2 began using natural gas as its fuel in 2016, with all units at Meramec planned to be retired by the end of 2022.*
- *Ameren Missouri is planning for additional retirements of fossil-fueled generating units during the planning horizon:*
    - *Assumed retirement by 2024 of 324 MW (summer net capacity) of older, less efficient gas and oil-fired CTGs.*
    - *Sioux Energy Center is assumed to be retired in 2033*
    - *Two Labadie Energy Center Units are assumed to be retired in 2036.*

Ameren Missouri owns and operates thermal, nuclear, hydroelectric and storage energy centers to serve the energy needs of its customers. About 95% of generation comes from its coal-fired, nuclear, and oil/natural gas-fired energy centers. Ameren Missouri regularly evaluates energy center performance and upgrades that are necessary to operate its plants in an efficient, safe, cost-effective and environmentally-friendly manner.

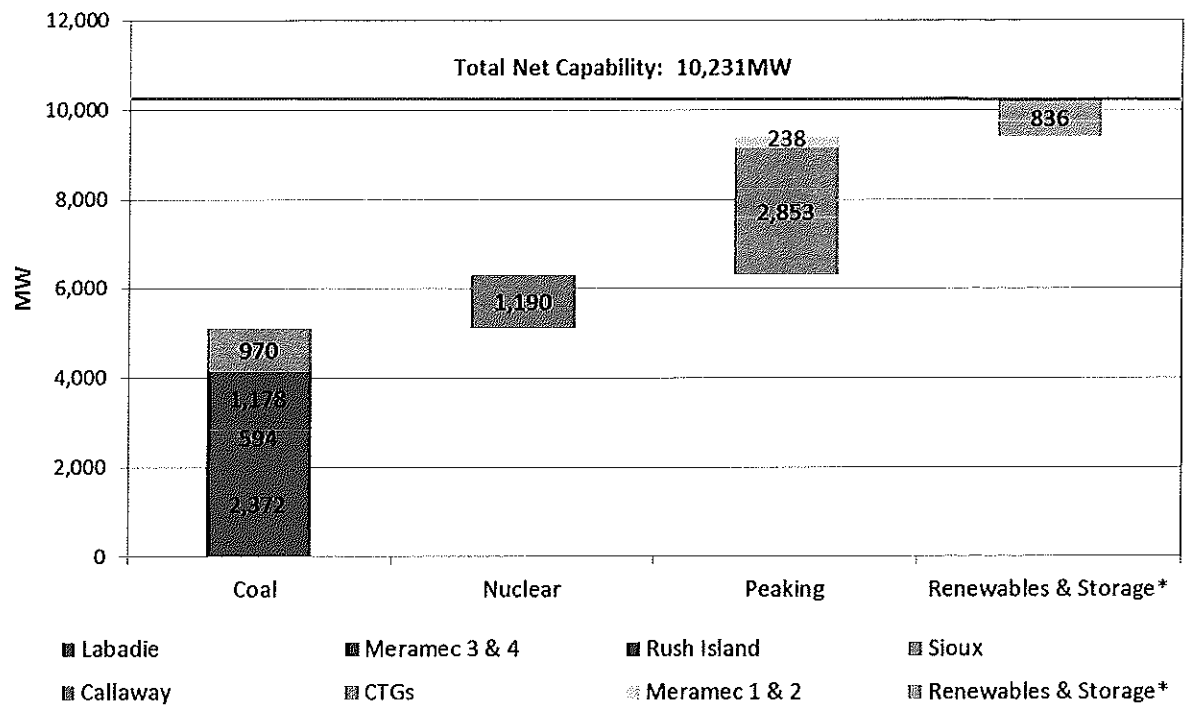
During the 20-year planning horizon, at existing energy centers, Ameren Missouri is planning to complete Keokuk Energy Center upgrades on Units 5 and 15 (the last of 15 main units), and retirement of the Meramec Energy Center, Sioux Energy Center, two units at Labadie Energy Center and seven older and less efficient CTG units.

Ameren Missouri has implemented various initiatives to maintain efficiency and reduce greenhouse gas (GHG) emissions at its existing facilities. Projects and work activities that restore efficiency lost due to equipment degradation or operating issues continue to be executed on a regular basis. Examples include high pressure turbine restoration work at Labadie and installation of split secondary air dampers at Sioux.

4.1 Existing Generation Portfolio[1]

Ameren Missouri owns and operates thermal, nuclear, hydroelectric and storage energy centers to serve the energy needs of its customers. Figure 4.1 reflects the 2017 summer net capability of Ameren Missouri's existing supply-side resources. Appendix A includes a unit rating summary table. Existing capacity position table for 2017-2037 can be found in Chapter 9-Appendix A and in the workpapers.

Figure 4.1 Existing Supply-side Resource Installed Capacity



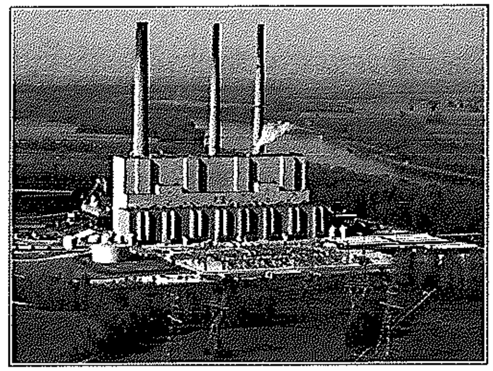
Note: *Renewables & Storage includes Keokuk, Osage, Taum Sauk, O'Fallon Solar and Maryland Heights Energy Centers

4.1.1 Existing Coal Resources

Ameren Missouri has four coal-fired energy centers in its generation fleet. The Labadie, Rush Island, Meramec, and Sioux energy centers have a total summer net generating capability of 5,114 MW.

[1] 4 CSR 240-22.040(1); 4 CSR 240-22.040(2)

Labadie Energy Center



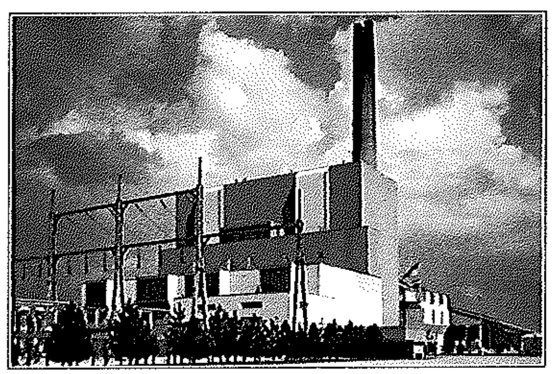
Labadie Energy Center is located outside Labadie, MO, on more than 1,100 acres adjacent to the Missouri River, 35 miles west of downtown St. Louis. The plant consists of four generating units with a summer net capability of 2,372 MW. The first unit started operating in 1970, and the plant was fully operational in 1973.

Labadie Energy Center is a national leader in generating electricity cleanly and efficiently:

- In 2013, Labadie was recognized as the Best Large Plant Performer by the Electric Utility Cost Group (EUCG) for its five year cost and reliability performance.
- In 2014, Navigant awarded Labadie a plant operational excellence award as the top performing large unit coal-fired energy center in the U.S.

Labadie 3 turbine efficiency was improved by approximately 7% following turbine restoration projects completed during a 2015 major outage. Labadie 4 turbine efficiency improved approximately 6% following similar projects in a Spring 2016 major outage. Numerous projects were completed at Labadie to comply with the EPA's Mercury and Air Toxics Rule (MATS) to reduce mercury and particulate emissions. Projects included new electrostatic precipitators on Units 1 & 2, rebuild of electrostatic precipitators on Unit 4 and installation of powdered activated carbon injection systems on all Units.

Rush Island Energy Center

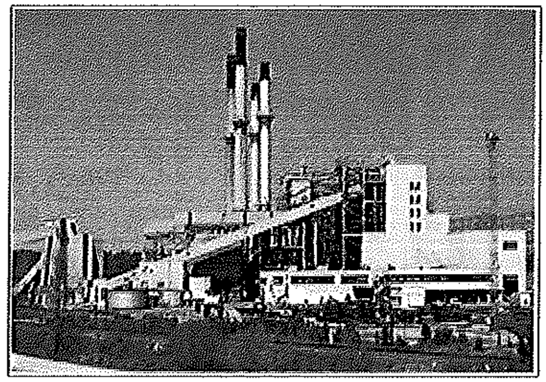


Rush Island Energy Center is located 40 miles south of downtown St. Louis, in Jefferson County, Mo., on 500 acres on the western bank of the Mississippi River. The plant has two units with a net summer capability of 1,178 MW. The first unit started operation in 1976 and the second unit in 1977.

In 2016, the HP and IP turbines were cleaned and some turbine seals and packing were replaced on Rush Island Unit 2. The cleaning and seal replacements will improve the efficiency of the HP and LP turbines.

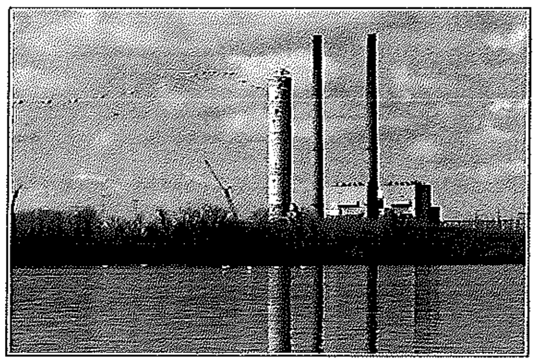
Rush Island was recognized in 2016 as Power Magazine's PRB Plant of the Year.

Meramec Energy Center



Meramec Energy Center is located in South St. Louis County on the Mississippi River on 420 acres. The first unit began operation in 1953 and the remaining three units were in service by summer of 1961. Net summer capability of the two coal-fired units at the site is 594 MW. In 2016, Units 1 & 2, representing 238 MW, began operating on natural gas. The facility is currently scheduled to be retired at the end of 2022.

Sioux Energy Center



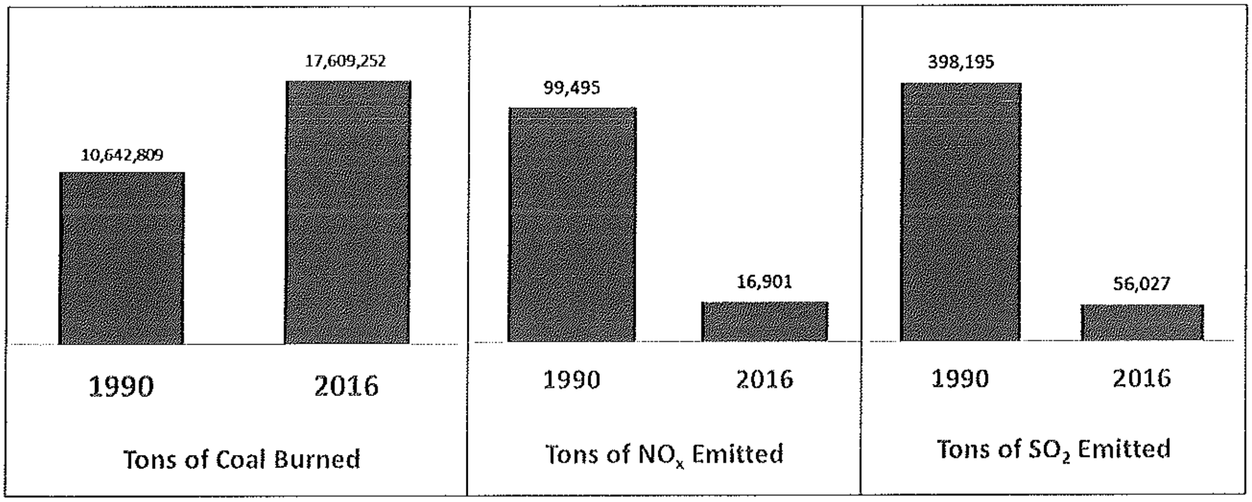
Sioux Energy Center is located in St. Charles County, Mo., 28 miles northwest of downtown St. Louis, on the Mississippi River. It consists of two cyclone boiler units which started operations in 1967 and 1968, respectively, and has a total net summer capability of 970 MW.

Both units at Sioux are equipped with wet flue gas desulfurization (FGD) equipment to comply with the Cross State Air Pollution Rule (CSAPR). CSAPR required significant reductions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions on a regional scale by 2015. The FGD system at Sioux also provides significant co-benefits in complying with EPA's MATS rule for both mercury and particulate emissions.

Historical Emissions from Coal Resources

Ameren Missouri has achieved dramatic decreases in SO_2 and NO_x emissions during the past two decades, despite an increase in the amount of coal consumed to meet our customers' growing energy needs over that period. Over the years, Ameren Missouri has been able to reduce pollutant emissions by using lower-sulfur fuels, by installing cleaner-emitting burners with computer-controlled operation, by improving operation of existing precipitators -- collecting more than 99% of particulates -- and by installing scrubbers at Sioux Energy Center. In addition, Ameren Missouri developed an early, progressive approach to meeting NO_x control regulations. Figure 4.2 shows the decrease in Ameren Missouri's SO_2 and NO_x emissions as coal consumption has increased.

Figure 4.2 NO_x and SO_2 Emissions Reductions



4.1.2 Existing Gas & Oil Resources

Ameren Missouri owns and operates oil- or natural gas-fired combustion turbine generators (CTG) to provide electricity during times of high demand or when its higher utilization plants are not operating due to a forced outage or scheduled maintenance.

In 2015, one of the CTG plants, Howard Bend, was retired. Table 4.1 lists the Ameren Missouri combustion turbines and their 2014 summer net generating capabilities. **____

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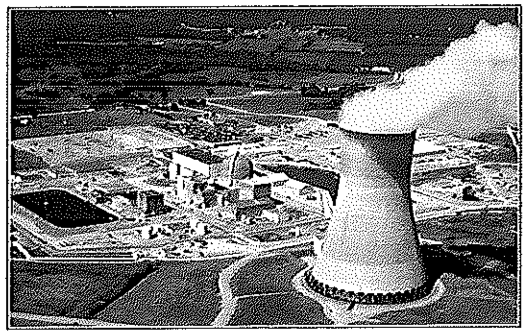
Table 4.1 CTG Capability

Audrain	Gas	600
Goose Creek	Gas	432
Kirksville	Gas	13
Pinckneyville	Gas	316
Raccoon Creek	Gas	300
Kinmundy	Gas/Oil	206
Meramec CTG	Gas/Oil	98
Peno Creek	Gas/Oil	188
Venice	Gas/Oil	487
Fairgrounds	Oil	54
Mexico	Oil	53
Moberly	Oil	53
Moreau	Oil	53
Total		2,853

[2] 4 CSR 240-22.040(3)(B)

4.1.3 Existing Nuclear Resource



Callaway Energy Center is located about 100 miles west of St. Louis, Missouri, in Callaway County. The plant started operations in December 1984 and is the only power plant that uses nuclear fuel in Ameren Missouri's generation fleet. Ameren Missouri continues to make cost-effective investments in Callaway to replace equipment that is at the end of service life, including components such as turbine rotors, steam generators and main transformers.

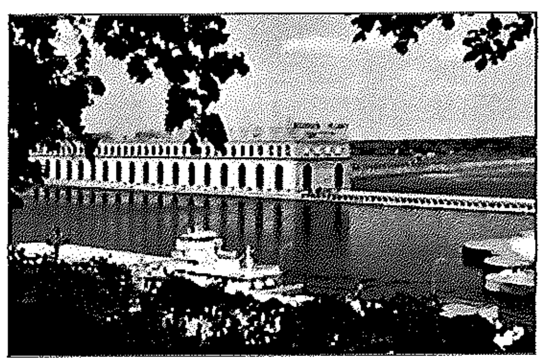
Callaway Energy Center is the second largest power generator on the Ameren Missouri system with a net capability of 1,190 MW.

4.1.4 Existing Renewable and Storage Resources

Currently, Ameren owns and operates 4.9 MW (AC) of solar generation, 385 MW of hydroelectric resources and 440 MW of pumped storage with an additional purchase power agreement for 102 MW of wind generation.

Existing Hydroelectric Resources

Keokuk



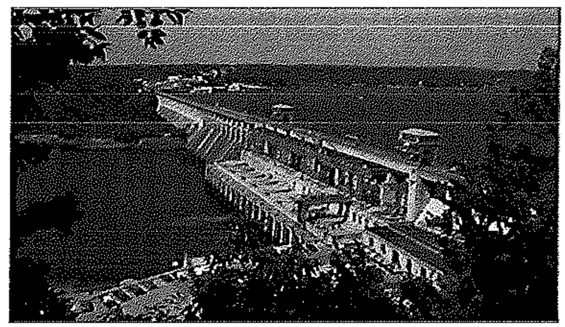
Ameren Missouri's Keokuk hydroelectric plant is located on the Mississippi River at Keokuk, Iowa, 180 miles north of St. Louis. The Keokuk Energy Center has a total net summer capability of 145 MW.

More than a million cubic yards of earth and rock were excavated to build the Keokuk dam and plant, which began operation in 1913. The history of the site as a power source began as far back as 1836, when Robert E. Lee conducted a survey for what was then known as the War Department and called attention to the power potential of this section of the Mississippi. An engineering marvel of its time, Keokuk is the largest privately owned and operated dam and hydroelectric generating plant on the Mississippi River. Over the years, Ameren Missouri has continued to invest in the modernization and repair of the plant and dam.
As it passes through the power plant, falling water spins turbines, or water wheels, which drive generators that produce electricity. Keokuk Plant is a "run-of-river plant,"

meaning that all water flowing downstream passes the plant on a daily basis. No water is stored. An average day of operation at Keokuk Plant saves the equivalent of nearly 1,000 tons of coal. The individual units at the Keokuk Energy Center, each having a nameplate rating of less than 10 MW, were certified as qualified renewable energy resources by the Missouri Department of Natural Resources (MoDNR) in September 2011.

Keokuk Energy Center completed two unit upgrades in December 2016. As a result, the ratings on Keokuk Units 6 and 14 are expected to increase by 2 MW each.

Osage



Ameren Missouri's Osage hydroelectric plant is located in Lakeside Missouri on the Osage River at the Lake of the Ozarks. The Osage Energy Center has a total net summer capability of 240 MW.

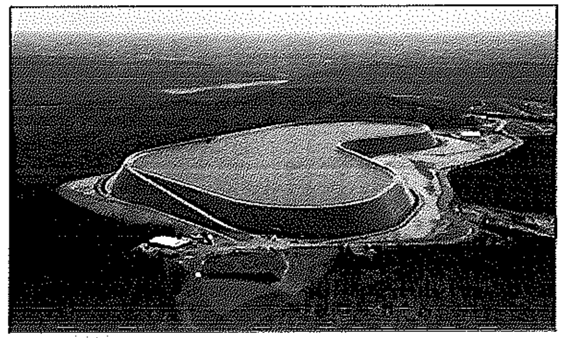
Osage began operation in 1931. For early settlers, the rolling Osage River in the heart of Missouri's Ozark wilderness provided a way of life and a source of livelihood, whether that was fishing, farming, logging or other pursuits. Then in the 1930s, the river was harnessed when Union Electric Company (now Ameren Missouri) built Bagnell Dam to provide power for a growing state and a budding economy. The 1930s-era building of Bagnell Dam and Ameren Missouri's Osage hydroelectric plant created a range of recreational opportunities in the now popular Lake of the Ozarks.

Every hour the Osage Plant operates, other energy resources are preserved. As water passes through the dam, the pressure of the falling water spins water wheels, which drive generators that produce electricity. In a typical year, Osage Plant uses the clean energy of falling water to produce as much power as 225,000 tons of coal or one million barrels of oil.

In 2017, Ameren Missouri started stability upgrades at Bagnell Dam to provide additional stabilization of the dam to conform with FERC guidelines. To stabilize the dam, 68 new plastic encapsulated state of the art post-tensioned anchors will be installed in the west retaining section, east retaining section, and spillway section. Additionally, mass concrete will be installed across the downstream side of the west and east retaining sections, which will reduce the number of anchors required. The project is expected to cost approximately $55M and is scheduled to be completed by December 2018.

Existing Pumped Storage

Taum Sauk



The Taum Sauk pumped storage plant is located approximately 120 miles southwest of St. Louis in the scenic Ozark highlands. The Taum Sauk Energy Center has a total net summer capability of 440 MW.

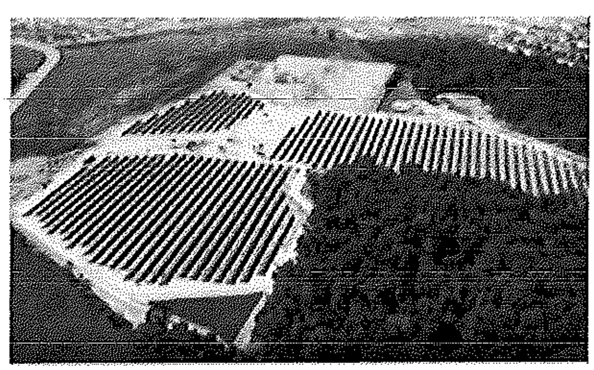
Taum Sauk Plant began operation in 1963, the turbines were completely rebuilt in 1999, and the upper reservoir rebuild project was completed in 2010. Taum Sauk is used primarily on a peaking basis and is put into operation when the demand for electricity is greatest. The pump storage system works much like a conventional hydroelectric plant, but is usually used only to meet daily peak power demands. Water stored in an upper reservoir is released to flow through turbines and into a lower reservoir during periods of high energy demand. Then, overnight, when the demand for electricity is low, the water is pumped back into the upper reservoir, where it is stored until needed.

Existing Renewables

Pioneer Prairie Wind Farm

In June 2009, Ameren Missouri executed an agreement to purchase 102 MW of wind power from Phase II of Horizon Wind Energy's Pioneer Prairie Wind Farm in northeastern Iowa in Mitchell County. The wind farm is fully operational with both phases having a total capacity of more than 300 MW. This Purchase Power Agreement runs from September 2009 through August 2024. The Pioneer Prairie Wind Farm was certified as a qualified renewable energy resource by the MoDNR in September 2011. The power Ameren Missouri is purchasing ties into the MISO transmission grid, of which the company is a member.

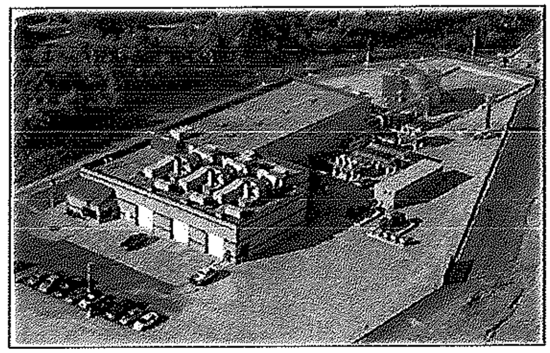
O'Fallon Renewable Energy Center



In December 2014 Ameren Missouri began operation of 4.8 MW (AC) of solar generation at the O'Fallon Renewable Energy Center. The O'Fallon facility includes more than 19,000 polysilicon solar panels covering 25 acres of land owned by Ameren Missouri. It is the largest investor-owned utility scale solar facility in Missouri and was certified as a qualified renewable energy resource in April, 2015 by Missouri Department of Economic Development (DED).

Ameren Missouri also owns approximately 100 kW of various PV solar technologies at its headquarters office building in St. Louis, which was certified as a qualified renewable generation facility by the MoDNR on September 28, 2011. The total generation of this facility during year 2015 was 89 MWh.

Maryland Heights Renewable Energy Center



The MHREC is located in St. Louis County approximately 18 miles northwest of St. Louis. The MHREC is the largest landfill-gas-to-electric facility in Missouri and one of the largest in the country, generating enough renewable energy to power approximately 10,000 average Missouri homes.

The MHREC began operation in June 2012. It has a total net summer capacity of 8 MW (net). This facility burns methane gas produced by the IESI Landfill in Maryland Heights, MO, in three Solar Mercury 50 gas turbines to produce electricity. The current contract with the landfill guarantees enough gas supply for three generators until 2022. In August 2012, the MHREC was certified as a qualified renewable energy resource by the MoDNR.

4.1.5 Levelized Cost of Energy Evaluation for Existing Resources[3]

The levelized cost of energy (LCOE) was calculated for Ameren Missouri's existing resources. LCOE represents going forward costs of ownership and operation and provides a basis for comparison to new resource alternatives. It is important to note that the LCOE figures do not fully capture all of the relative strengths of each resource type. Table 4.2 shows the component analysis for the LCOE for each energy center. The average LCOE for Ameren Missouri's coal energy centers is approximately \$42/MWh. The average LCOE for Ameren Missouri's entire generating fleet is approximately \$43/MWh.

[3] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(C)1

Table 4.2 Levelized Cost of Energy Component Analysis for Existing Resources

Existing Resources	Levelized Cost of Energy (¢/kWh)										
	Non-Environmental Costs					Probable Environmental Costs					Total Cost
	Non-Env Capital	Fixed and Variable O&M	Fuel	Decommission	Pump MWh	Env Capital	Env O&M	CO2	SO2	NOx	
Labadie	0.55	0.30	2.15	--	--	0.16	0.04	0.27	0.00	0.03	3.49
Rush Island	0.54	0.40	2.35	--	--	0.20	0.03	0.38	0.00	0.00	3.92
Meramec	0.67	2.31	2.37	--	--	1.49	0.04	0.00	0.00	0.01	6.88
Sioux	0.67	0.65	2.23	--	--	0.35	0.04	0.17	0.01	0.01	4.12
Audrain	0.50	0.29	5.65	--	--	--	0.00	0.17	0.00	0.00	6.61
Goose Creek	1.47	0.52	5.38	--	--	--	0.00	0.16	0.00	0.00	7.54
Kirksville	0.10	0.04	7.87	--	--	--	--	0.00	0.00	0.00	8.01
Pinckneyville	0.77	1.46	4.53	--	--	--	--	0.14	0.00	0.00	6.89
Raccoon Creek	0.23	0.74	5.63	--	--	--	--	0.17	0.00	0.00	6.77
Kinmundy	0.89	1.19	5.10	--	--	--	--	0.15	0.00	0.00	7.33
Meramec CTG	2.52	0.17	5.60	--	--	--	--	0.00	0.00	0.00	8.30
Peno Creek	0.86	1.66	4.91	--	--	--	--	0.15	0.00	0.00	7.57
Venice	0.57	0.85	4.91	--	--	--	--	0.15	0.00	0.00	6.48
Fairgrounds	0.04	0.24	7.87	--	--	--	--	0.00	0.00	0.00	8.15
Mexico	0.06	0.42	8.03	--	--	--	--	0.00	0.00	0.00	8.51
Moberly	0.06	0.39	5.33	--	--	--	--	0.00	0.00	0.00	5.79
Moreau	0.04	0.28	8.79	--	--	--	--	0.00	0.00	0.00	9.12
Callaway	1.32	1.81	0.79	0.07	--	--	--	0.00	0.00	0.00	4.00
Keokuk	1.91	0.50	0.00	--	--	--	--	0.00	0.00	0.00	2.40
Osage	4.65	1.20	0.00	--	--	--	--	0.00	0.00	0.00	5.85
Taum Sauk	3.29	1.66	0.00	--	4.78	--	--	0.00	0.00	0.00	9.73
Maryland Heights CTG	1.14	3.05	8.05	--	--	--	0.00	0.00	0.00	0.00	12.24
O'Fallon (Solar)	0.00	0.41	0.00	--	--	--	0.00	0.00	0.00	0.00	0.41

4.1.6 Planned Changes to Existing Non-Coal Resources

During the 20-year planning horizon, Ameren Missouri is considering two Keokuk Energy Center Units for upgrades, adding a new CTG unit at MHREC, and the potential retirement of seven CTG units.

Portfolio Upgrades

Keokuk Energy Center completed upgrades to Units 6 and 14 in December 2016. The net output is expected to increase by 2 MW each with a total capital cost of approximately $24 million. In addition, upgrades at Keokuk Energy Center for Units 5 and 15 are scheduled to be complete in 2019. The net output Keokuk will increase by 2 MW each with a total capital cost of approximately $25 million (for the turbine component upgrades only) budgeted in 2017, 2018, and 2019.

Ameren Missouri is considering adding a fourth CTG unit at MHREC that will be in service in 2025. The fourth unit will provide an additional 3-4 MW of summer net capacity with a total capital cost of $16-18 million in 2024-2025 and will provide additional renewable energy needed for meeting the requirements of Missouri's Renewable Energy Standard (RES).

CTG Retirements

In 2013, Ameren Missouri conducted a high level retirement evaluation of the existing CTG fleet. The potential retirement recommendation is based on operating experience, condition of the assets, and qualitative analysis. The qualitative analysis considered factors such as condition of subsystems, obsolesce of control systems, availability of spare parts, and building condition. Based on the evaluation, Ameren Missouri should consider retiring some or all seven of its older gas- and oil-fired CTG units (i.e., Kirksville, Fairgrounds, Meramec CTG-1, Meramec CTG-2, Mexico, Moberly, and Moreau) with a total net capacity of 367 MW over the next 20 years. A combination of factors lead to the potential CTG retirement recommendations, including the fact that the average age of seven of the units is 41 years; and for some of the units, the long-term availability of spare parts is questionable. The lead time for obtaining spare parts is unknown. Table 4.3 provides a summary of the planned CTG retirements. The planned CTG retirements are included in the base capacity position (see Appendix B). Howard Bend was retired in early 2015 due to the age of the unit, long-term availability of spare parts, safety and the poor economics associated with refurbishment.

Table 4.3 Ameren Missouri Potential CTG Retirements during the Planning Period

Unit	Capacity (MW)	Fuel Type	Commerical Operation Date	Age as of 12/31/2016	Retirement Time Frame
Kirksville	13	Natural Gas	1967	49	12/31/2021
Fairgrounds	54	Oil	1974	42	12/31/2021
Meramec CTG-1	54	Oil	1974	42	12/31/2021
Meramec CTG-2	44	Natural Gas/Oil	1999 (1)	40	12/31/2021
Mexico	53	Oil	1978	38	12/31/2023
Moberly	53	Oil	1978	38	12/31/2023
Moreau	53	Oil	1978	38	12/31/2023

Note: (1) Meramec CTG 2 was acquired by Ameren Missouri in 1999 and is 1976 vintage.

The results of a detailed condition assessment for each unit will be used as the basis for economic analysis to be considered along with other factors such as overall age, condition, reliability, safety and cost, significant capital needs, near-term capacity value and availability of spare parts.

4.2 Existing Steam Generation Evaluation

Ameren Missouri has evaluated its coal energy centers in terms of condition, base retirement assumptions, reliability trends, operation and maintenance costs, and capital expenditures. Table 4.4 lists the commercial operation date for each generating unit, the average age at each energy center as of 12/31/2016, and the base retirement assumptions based on the 2014 Black & Veatch Report on Life Expectancy of Coal-Fired Power Plants.

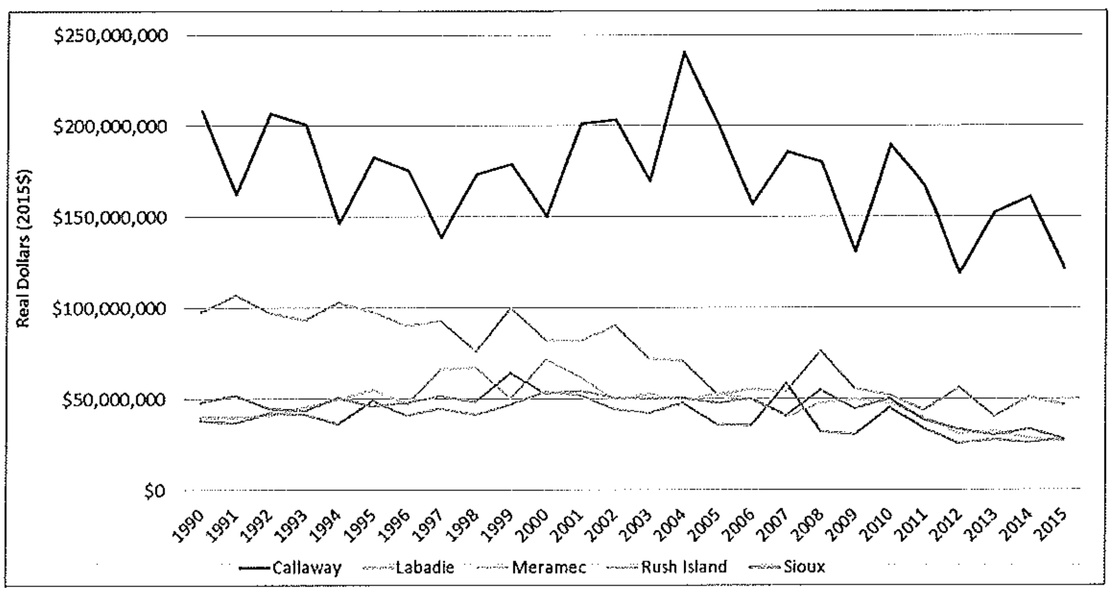
Table 4.4 Ameren Missouri Coal Energy Center Commercial Operation Dates, Average Age, and Base Retirement Assumptions

	Commercial Operation Date				Average Age as of	Base Retirement Assumptions
Energy Center	Unit 1	Unit 2	Unit 3	Unit 4	12/31/2016	(Retirement Date)
Labadie	1970	1971	1972	1973	45	2042
Meramec	1953	1954	1959	1961	60	2022
Rush Island	1976	1977			40	2045
Sioux	1967	1968			49	2033

4.2.1 Operations and Maintenance Costs

Figure 4.3 shows the historical operations and maintenance (O&M) costs for Ameren Missouri's four coal-fired energy centers from 1990 to 2015. The plant O&M costs were taken from the annual plant operating reports and then normalized to 2015 dollars using the Handy Whitman Index for Total Steam Production Plant. The average annual escalation for the period 1990 to 2015 was 3.2%. These costs are non-fuel O&M expenses. O&M has a relatively moderate downward trend in the last 10-15 years.

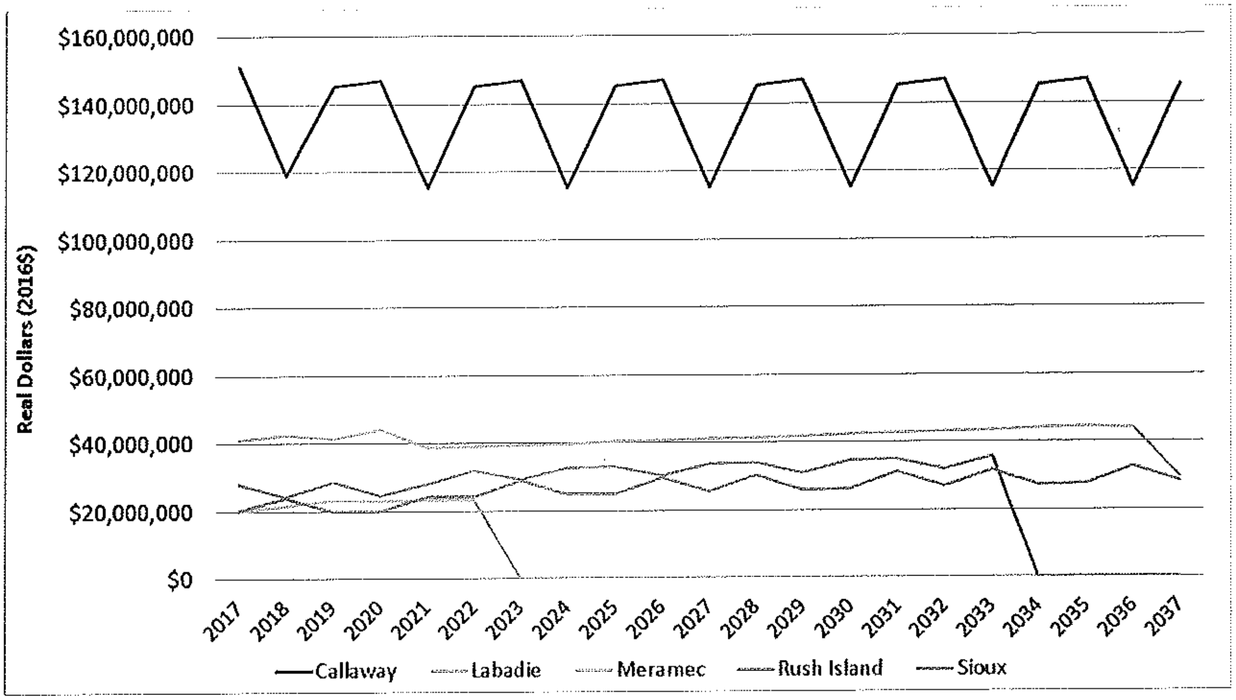
Figure 4.3 Historical Annual O&M for Ameren Missouri Energy Centers (2015$)



The plant O&M costs are anticipated to remain relatively flat in real terms in the future. Figure 4.4 shows the future O&M costs from 2017 to 2037 in 2016 dollars. The labor portion of the O&M assumes a 50% pension and benefit loading factor. In addition, the O&M forecasts assume annual revenues from refined coal operations at Rush Island

and Sioux from 2014 through 2021. A 4-year outage cycle for Labadie, a 5-yr outage schedule for Rush Island and a three-year outage cycle for Sioux are assumed in the O&M forecast. In the retirement year of each plant, what would otherwise be capital expenditures are included in O&M costs for modeling purposes.

Figure 4.4 Future Annual O&M for Ameren Missouri Coal Energy Centers (2016$)



4.2.2 Capital Expenditures

Figure 4.5 shows the historical non- environmental capital expenditures from 2001 to 2016. The plant capital expenditures were taken from the Ameren Missouri accounting system and normalized to 2016 dollars using a 2% escalation rate.

Figure 4.5 Historical Non-Environmental Capital Expenditures for Ameren Missouri Coal Energy Centers (2016$)

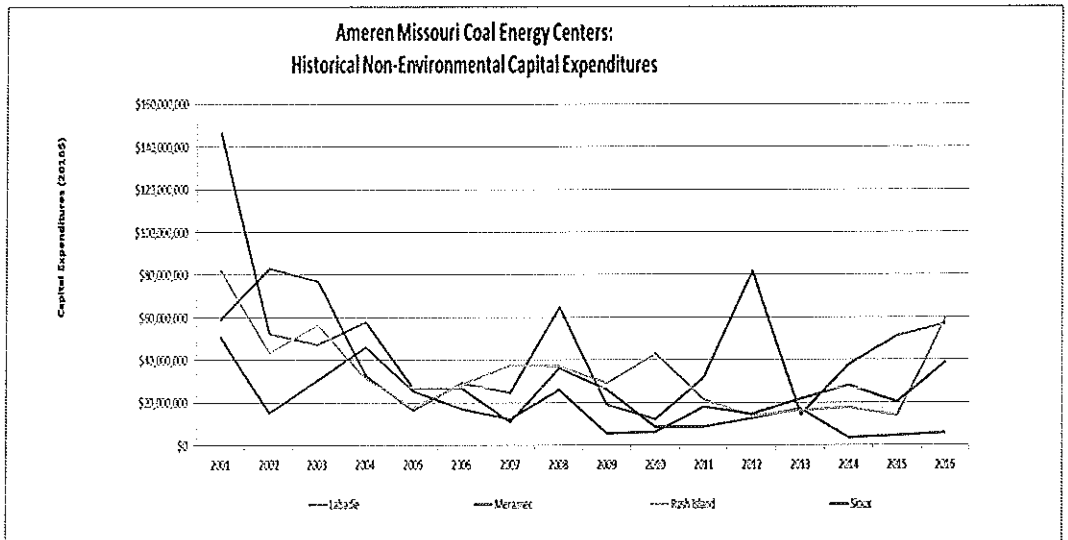
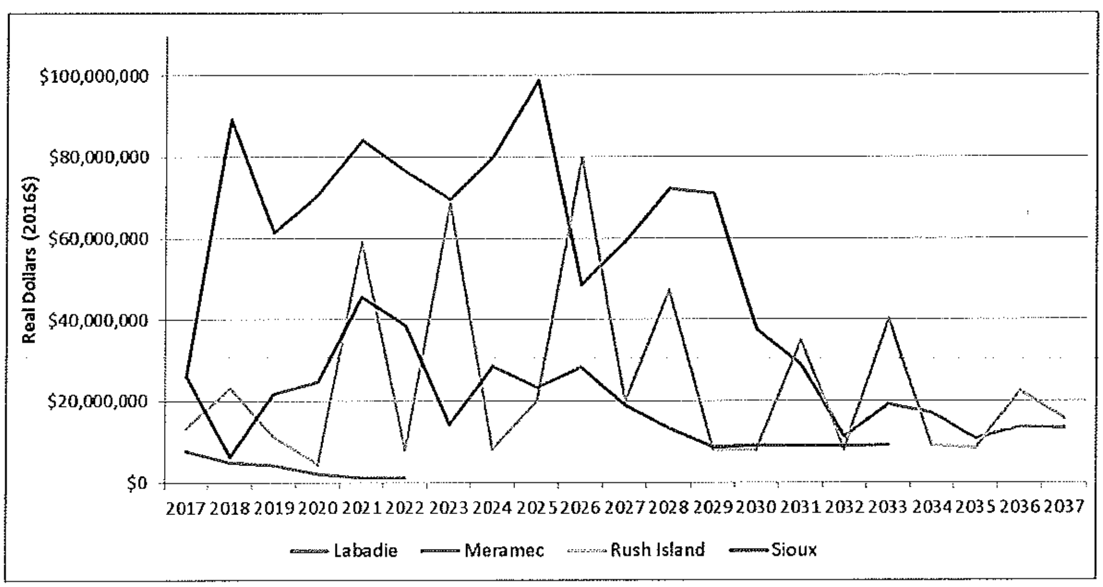


Figure 4.6 shows the future non-environmental capital expenditures for 2017 to 2037. Future environmental capital expenditures are discussed in Chapter 5. The future non-environmental plant capital expenditures were provided by Ameren Missouri Power Operations Services and normalized to 2016 dollars using a 2% escalation rate. Labadie's capital expenditures show a slight increasing trend over time due to boiler and landfill projects. Meramec and Sioux energy centers show a decreasing trend in non-environmental capital expenditures over the time period. Rush Island capital expenditures are expected to remain relatively flat over the time period.

Figure 4.6 Future Non-Environmental Capital Expenditures Ameren Missouri Coal Energy Centers (2016$)



4.3 Efficiency Improvement[4]

4.3.1 Existing Facility Efficiency Options

Ameren Missouri has implemented various initiatives to improve efficiency and reduce GHG emissions at its existing facilities. These initiatives include replacement of incandescent light bulbs with compact fluorescent light bulbs, and standardization of low-energy usage light fixtures during system replacements. Another initiative to improve efficiency and reduce GHG emissions in the operation of heating, ventilation, and air conditioning (HVAC) equipment through the installation of programmable thermostats for control of HVAC systems is expected to reduce energy consumption during off-hours. The projects completed in 2011 through 2015 will reduce energy consumption by more than 3,400 MWh annually and reduce CO2 emissions by more than 3,200 metric tons annually (assuming 0.94 metric tons of CO_2 per MWh). Ameren Missouri will continue assessing and implementing the projects that prove to be feasible on an ongoing basis.

Ameren Missouri has monitored the performance, costs, and benefits of light-emitting diode (LED) street lighting technology for many years. Starting in 2016, Ameren Missouri began a project to replace 125,000 company-owned street lighting fixtures (66% of existing street lights) with LEDs by 2022. Subsequent analysis identified an additional 15,000 company-owned lights (an additional 7% of existing street lights) that could be cost-effectively replaced with LEDs; and replacement for these lights began in the summer of 2017 with a five year completion goal. Furthermore, Ameren Missouri has agreed to replace 15,000 customer-owned street lights. The replacement of these street lights began in 2017 and is expected to be completed by 2023. These changes will benefit both customer rates and the environment. Upon installation, the LED street lights will result in immediate bill savings for lighting customers and once completed the LED street lights will reduce carbon emissions by 96,000 metric tons annually. Ameren Missouri is actively exploring cost effective LED replacement options for its remaining company-owned street lights as well as additional options for customer-owned street lights.

In late April 2016, Ameren Corporation published its fourth-ever corporate social responsibility report: a microsite available at AmerenCSR.com. The report details Ameren's commitment to energy sustainability and how the company works to balance its responsibilities to customers, shareholders, the environment and employees. In the report Ameren addresses a range of topics, including environmental performance, community betterment and financial strength. Ameren's report was recently recognized

[4] 4 CSR 240-22.040(1)

as one of the Top 100 Reports Worldwide, ranking #20 out of 1,000+ companies in the League of American Communication Professionals' (LACP) Vision Awards.

4.3.2 Existing Energy Center Efficiency Options[5]

Ameren Missouri continues to be focused on maintaining the efficiency of its coal-fired generating units. Projects that improve efficiency that are a benefit to the company and to customers continue to be evaluated and executed when appropriate. Projects and work activities that restore efficiency lost due to equipment degradation or operating issues continue to be evaluated and executed on a regular basis.

Ameren Missouri performs long-term scheduled major maintenance outages. Much of the work performed during these major outages (such as replacement or repair of leaking valves, restoration of duct work, insulation of equipment, and cleaning of equipment) typically results in improved efficiency when the unit returns to service. For example, high pressure turbine restoration work on Labadie Unit 3 improved turbine efficiency by approximately 7% following a major outage in 2015, and similar work on Labadie Unit 4 improved high pressure turbine efficiency by approximately 6% following a major outage in 2016. On Sioux Unit 1, the installation of split secondary air dampers on the boiler in late 2016 is estimated to provide a 1% unit efficiency improvement based on a previously completed project on Sioux Unit 2.

Operational monitoring at Ameren Missouri's coal plants is also an important tool in maintaining the heat rate (efficiency) at the coal plants. EtaPRO is a continuous monitoring software tool used at all the plants to monitor thermal performance of critical equipment. The EtaPRO system is maintained by Performance Engineering and is also used by performance engineers to generate plant heat rate (efficiency) reports. Operations personnel routinely check system components during operation and start-up modes to insure that valve line-ups are correct and equipment performance is maintained.

[5] 4 CSR 240-22.040(1)

4.4 Compliance References

2. Planning Environment

Highlights

- *General economic conditions suggest flat to negative growth, resulting in lower loads when combined with increasing energy efficiency.*
- *Natural gas prices continue to be driven by large domestic supplies of shale gas, and our assumptions span a range of $2.50 - $5 per MMBtu in today's dollars over the planning horizon.*
- *Environmental regulations coupled with relatively low gas prices and slow load growth will continue to drive additional retirements of coal-fired generation*
- *Ameren Missouri has developed and modeled 15 scenarios, comprising ranges of values for key variables that drive wholesale power prices, for use in evaluating its alternative resource plans.*

In evaluating our customers' future energy needs and the various options to meet them, it is necessary to consider current and future conditions under which we must meet those needs. Ameren Missouri continuously monitors the conditions and circumstances that can drive or influence our decisions. Collectively, we refer to these conditions and circumstances as the "Planning Environment." This Chapter describes the basis for the assumptions used in our analysis of resource options and the performance of the alternative resource plans described in Chapter 9.

2.1 General Economic Conditions

General economic conditions have continued to improve in the U.S. over the last few years. Ameren Missouri's expectations are for relatively stable longer term growth, but at a slower pace than has been observed historically, in the 2-2.5% range per year. Generally, demographic factors will provide the greatest long term challenge to growth, as the growth in the labor force, one of the key components of long-term economic growth, is expected to be below its historical rate as the Baby Boomer generation continues to enter retirement. Also, the federal budget picture in the U.S. poses risks to the country's long-term economic health if reforms are not made to either tax or spending policies in order to bring the national debt to GDP ratio onto a stable trajectory. That said, our base expectation is for economic growth at the national level to continue throughout the planning horizon of the IRP at a steady but modest pace by historical standards, subject to normal business cycle variability.

Ameren Missouri's outlook for the local economy of its service territory is less optimistic than the national outlook. For a period of several decades, the St. Louis Metropolitan Area and surrounding parts of eastern Missouri have seen negative net migration. Simply put, more people have moved away from the area than those relocating to the area to take their place. This has caused the population to grow more slowly than many other major cities and the country as a whole. While this trend has started to reverse very recently, the St. Louis area is expected to continue to experience population growth at a slow pace relative to other parts of the country. Because the majority of economic activity is local in nature, population growth that is slower than the national average generally goes hand-in-hand with slower economic growth. Based on these long-term demographic trends, we expect the Ameren Missouri service territory to grow at around half the pace of the U.S. economy. We also expect long-term general inflation to approximate 2%.

The development of regulations that can impact a utility's resource planning have continued to evolve in recent years. These regulations include current EPA regulations regarding emissions primarily from our fossil fueled power plants, regulatory requirements at our Callaway nuclear facility, and an evolving landscape of renewable energy standards currently at the state level along with energy efficiency policies and incentives. At the same time, methods for providing cost recovery and incentives associated with such regulations have been considered, and continue to be considered, by utility regulators in the various states. This confluence of regulatory currents intersects at the point of integrated resource planning, and the changing nature of the regulatory environment embodies one of the most important considerations when making long-term resource decisions. A complete assessment of current and future environmental regulations and mitigation is presented in Chapter 5. Considerations with respect to cost recovery treatment are included in our discussion of resource strategy selection, in Chapter 10.

2.2 Financial Markets[1]

An ambitious post-election economic agenda provides a robust backdrop for longer term economic growth expectations. The anticipated major tax cuts, increased defense spending, reduced regulations and infrastructure spending are all prospective long-term drivers for a stronger expanding economy. Much of this enthusiasm must be tempered in the back drop of the United States having a large debt to GDP ratio, low inflation and low unemployment. These headwinds will likely temper growth rates even in an accommodative environment for growth. This setting has provided the expectation for modestly stronger long term economic growth and inflation to be slightly higher than

[1] 4 CSR 240-22.060(2)(B); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(5)(B)

previous expectations. Interest rates will likely normalize at a slightly faster pace and the new normal neutral federal funds rate could be marginally higher

For this IRP, long-range interest rate assumptions are based on the December 1, 2016, semi-annual Blue Chip Financial Forecast. This forecast is a consensus survey of 49 economists from numerous firms including banks, investment firms, universities and economic advisors. Table 2.1 shows the analyst expectations for the yield on 10-year Treasury notes annually for 2018-2022 and a five-year average estimate for 2023-2027.

Table 2.1 Forecast Yield: 10-year Treasury Notes **

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Long-term allowed return on equity (ROE) expectations for Ameren Missouri were developed using the projected long-term risk-free interest rate identified for 2023-2027 in Table 2.1. Ameren Missouri's forward equity risk premium was calculated by applying a linear fit calculated relationship between historical electrical authorized ROE and 10 year treasury notes. This relationship provides an implied risk premium that can be determined based on an expected treasury rate. Using this approach, the resulting expected value of allowed ROE is 10.6% as shown in Table 2.2.

Table 2.2 Projected Allowed ROE **

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The assumed range of interest rates for the 2017 IRP are calculated from an average of Blue Chip Financial Long Range forecasts for Corporate Aaa and Corporate Baa bond yields for the 2023-2027 timeframe. The base Consensus forecast became our base assumption and the top ten analyst average our high case and the lower 10 analyst average our low case, roughly corresponding to the top 20% and bottom 20% of the range, respectively.

Table 2.3 Interest Rates **

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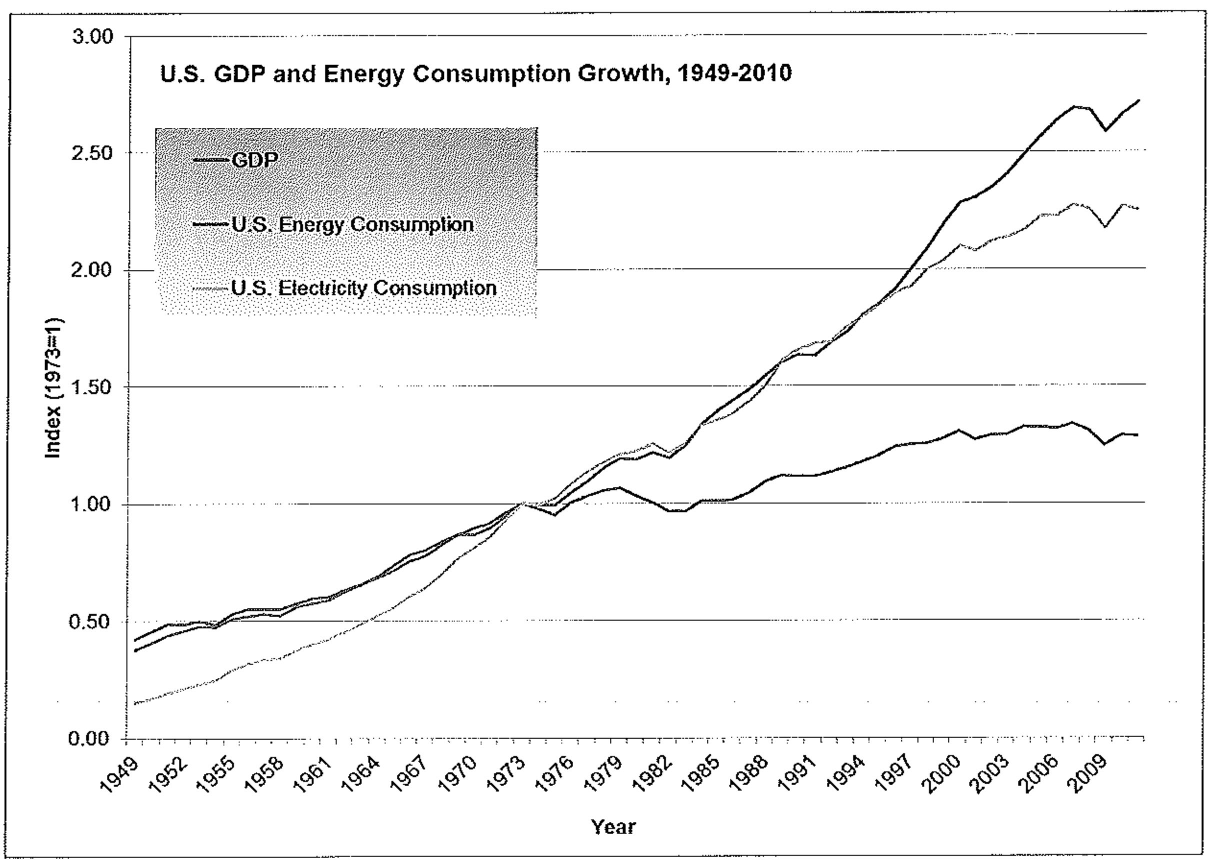
Because planning decisions are made in the present, Ameren Missouri uses its current weighted average cost of capital as the discount rate for evaluating present value revenue requirements and cash flows. Based on Ameren Missouri's most recently completed general rate case, our assumed discount rate is 5.95%. This is based on a capital structure that is 48.2% debt, 51.8% equity, and an allowed ROE of 9.53%.

2.3 Load Growth[2]

Load growth is typically a key driver of the market price of wholesale electric energy. The largest factor likely to affect load growth is the expected range of economic conditions that drive growth for the national economy and the energy intensity of that future economic growth. Historical trends in the energy intensity of the U.S. economy were studied in 2014 to establish baseline trends.

That study revealed that the U.S. economy has exhibited long-term trends toward decreasing energy intensity (i.e., less energy input required per unit of economic output). Figure 2.1 illustrates this point.

Figure 2.1 Energy Intensity Trends



[2] 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(A); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

The chart shows several decades of U.S. GDP, total U.S. energy consumption, and total U.S. electricity consumption, all indexed so that they take on a value of 1 in the year 1973. When you overlay these three data series on the graph, there are some interesting and clear takeaways that are apparent regarding trends in national energy intensity. From 1949-1973 total energy consumption in the U.S. grew almost 1:1 with economic output, as illustrated by the correlation of the red and blue index lines during those years. This period was characterized by significant growth in the nation's manufacturing base, as well as widespread adoption of energy intense transportation and home appliances.

Around 1973, there was a clear change in the pattern, as total energy consumption grew markedly slower than economic output. This was around the time of the first oil embargo and energy price shocks that heightened the focus of the country on energy efficiency. The changes ushered in by those events clearly impacted total energy consumption, but as is apparent from the graph, total electricity consumption (a subset of total energy consumption (represented by the green line) continued to grow in virtual lock step with economic output (the blue line) until about 1990. This period of time saw expanded electrification of industrial processes as capital replaced labor at a high rate, increasing the electrical intensity of the economy. Additionally, air conditioning and other home conveniences were experiencing rapid growth in saturation rates at this time, supporting electric load growth.

From 1990 forward, the same trends that appeared in total energy consumption much earlier appeared in the electricity consumption. The growth of many home and business end uses began to slow as higher levels of saturation of air conditioning and other conveniences were realized. Additionally, federal standards led to improvements in the efficiency of many end use electrical appliances, such as the first refrigerator efficiency standards that date to this era. Finally, the most energy intensive regions of the manufacturing base of the nation began a long period of decline as many industries moved overseas in an effort to achieve lower labor costs.

It is apparent from this macro analysis of trends that the U.S. economy has, for decades, made strides in reducing the energy intensity of economic output, or said another way, become more energy efficient. With that backdrop, our expectation is that that overarching trend will continue. With that said, in order to assess the potential magnitude of future declines in energy intensity the key factors that drive energy intensity are considered independently. Those factors include expectations for trends in manufacturing, as manufacturing economic output is generally about three times as energy intensive as non-manufacturing activity. The recent boom in production of natural gas using horizontal drilling and hydraulic fracturing technology has the potential to cause resurgence in domestic manufacturing, particularly in the chemicals industry for which gas is an important feedstock.

Additionally, trends in energy efficiency, both efficiency induced by utility programs and that realized through building codes, appliance standards, and "naturally occurring," or economically induced efficiency, were assessed. Many states have established Energy Efficiency Resource Standards that will serve to promote adoption of end use technologies that use less energy to perform the same function as previous technologies. The goal of increasing the energy efficiency of end use appliances and equipment is also furthered by federal standards that require improving performance from many electrical applications.

Also, proliferation of customer-owned distributed generation, which appears as a reduction in demand for energy from utilities was studied as something that may have a meaningful impact over the planning horizon. While solar photovoltaic has seen rapid growth in some Southwestern U.S. markets with high solar irradiance, it has started to take on a more prominent role, spurred by various federal and state incentives, in other parts of the country, including in Missouri. While the future of solar equipment costs is uncertain in terms of the timing and magnitude, it is probable that the economics of solar will continue to improve over the planning horizon.

Considering the foregoing, our near term expectation is that load growth will be essentially flat through the 2017 time frame. After 2017, we have assumed a negative 0.37% average annual growth in load for the Eastern Interconnect across the 20 year planning horizon. A negative 0.37% rate of load growth would essentially equate to an acceleration of the reduction in energy intensity trends that were observed for much of the last decade, applied to our base case assumptions regarding future economic growth.

To reflect the uncertainty for a higher growth case which may result from factors such as a more robust energy intense GDP driven by an increase in manufacturing and the potential for greater penetration of electric vehicles, an annual average growth rate of 0.48% was assumed. 0.48% growth would result from an energy intensity trend similar to that observed in the early 2000's applied to expected economic growth. Again, this would be most likely in the event that the secular decline in manufacturing reversed and we saw growth in chemical industries driven by shale gas or more heavy industries that return operation to the U.S. as overseas labor markets mature and increase in cost.

Finally, to reflect a low growth case in which a combination of accelerating adoption of distributed generation and robust energy efficiency programs could easily provide an expectation for a negative 1.36% average growth rate across the planning horizon. While there is no historical precedent for a period with economic growth and negative load growth, an acceleration of aggressive efficiency standards and programs coupled with rapid deployment of distributed energy technologies could offset the energy consumption driven by economic forces for a considerable period of time under the right circumstances.

2.4 Reliability Requirements

Ameren Missouri remains a member of the Midcontinent Independent System Operator (MISO) and participates in its capacity, energy and ancillary services markets. MISO has established a process to ensure resource adequacy through Module E of its FERC tariff. Module E establishes an annual resource adequacy construct which requires load-serving entities to demonstrate adequate resource capacity to satisfy expected load and reserve margins. MISO establishes its planning reserve margin (PRM) requirements annually through its loss of load expectation (LOLE) study process. MISO's last LOLE study report, published in late 2016, indicates a planning reserve margin requirement of 15.6% (applied to peak demand) in 2017. Table 2.4 shows the year-by-year PRM requirement through 2026. Ameren Missouri has assumed that the PRM beyond 2026 remains at 15.7%.

Table 2.4 MISO System Planning Reserve Margins 2018 through 2026

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026
PRM Installed Capacity	15.6%	15.3%	15.4%	15.5%	15.5%	15.6%	15.6%	15.7%	15.7%

In addition to establishing the PRM requirements, MISO also establishes a capacity credit for wind generation. The capacity credit is applied to the net output capability (in MW) of a wind farm to determine the amount of capacity that can be counted toward the PRM for resource adequacy. The MISO's value for wind capacity credit based on the 2017 Resource Adequacy report is 15.6%.

2.5 Energy Markets

Energy market conditions that may affect utility resource planning decisions include prices for natural gas, coal, nuclear fuel, and electric energy and capacity. Natural gas prices in particular continue to have a strong influence on energy prices as on-peak wholesale prices are often set by gas-fired generators. Ameren Missouri has updated its assessment of these key energy market components to serve as a basis for analysis of resource options and plans.

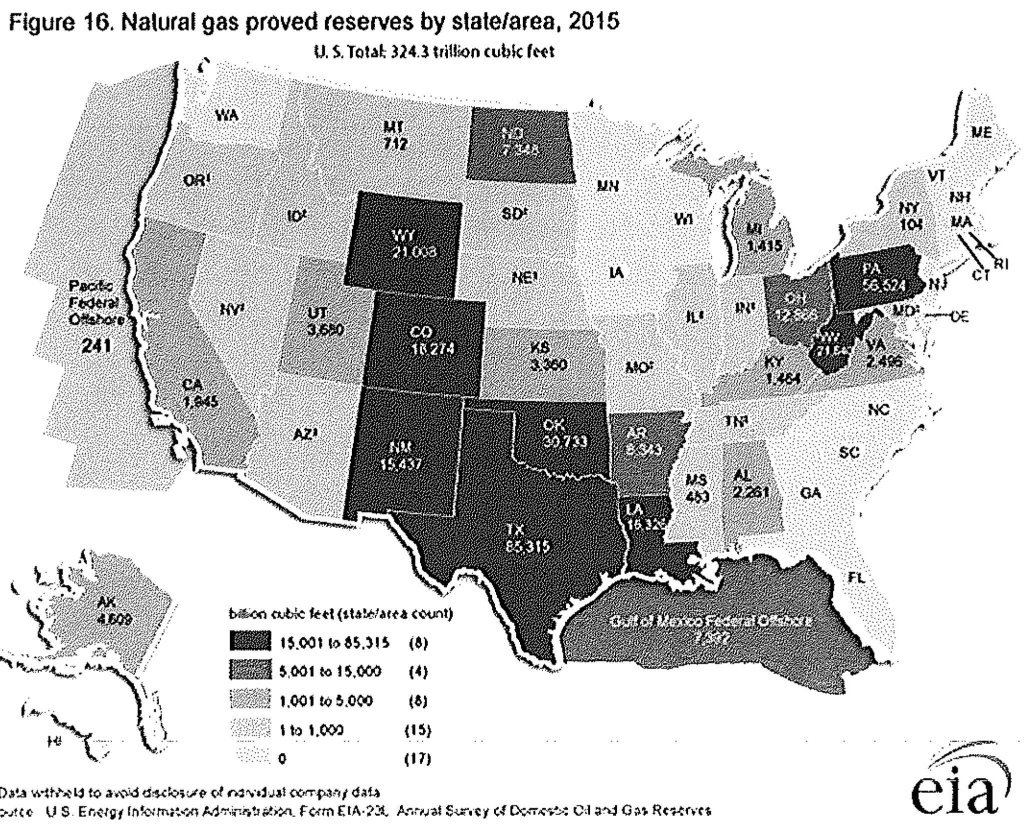
2.5.1 Natural Gas Market[3]

Our updated assumptions for natural gas prices reflect Ameren Missouri's most current expectations developed by internal subject matter experts on natural gas markets. The Company's general expectations for the fundamentals affecting natural gas supply, demand and markets are largely unchanged from our most recent IRP annual update. The natural gas industry has experienced significant improvements in production efficiency capability and pipeline infrastructure investment. Natural gas supplies are projected to be abundant, reliable and an economic fuel for the long term.

Natural Gas Price Drivers

Supply – The supply of natural gas continues to be robust with development of resources in the U.S. and in Canada. The shale gas plays have proven to hold greater reserves than initially estimated. The Energy Information Agency (EIA), shows in Figure 2.2 that natural gas production has grown nearly 4% per year since 2005 and is expected to continue to grow at that rate until 2020.

Figure 2.2 North American Natural Gas Reserves



[3] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

Technology advancements continue to improve the productivity, energy efficiency and environmental performance of drilling sites. Natural gas production in the Lower 48 states has increased from 50 billion cubic feet (Bcf) per day in 2006 to 74 Bcf per day in 2015, an increase of nearly 50 percent. However, some state and federal regulators continue to challenge hydraulic fracturing (fracking) technology through drilling moratoriums or stringent regulations. Recent low prices have begun to dampen production in regions where production costs are marginally profitable. The current relatively low price environment has resulted in a large number of wells that have been drilled but are uncompleted. Production is expected to increase as new demand pushes prices to more profitable ranges for most production areas.

Demand – Natural gas consumption remains relatively unchanged for the residential and commercial markets as energy efficiency improvements offset modest housing starts and new commercial space. The favorable characteristics of natural gas; relatively clean emissions, low current and expected prices, reliable and abundant supplies make it an attractive fuel to support industrial growth and electric generation. The combination of low prices for natural gas and federal energy policy developments connected with clean energy standards and greenhouse gases (GHG) are expected to increase demand for natural gas-fired generation. These factors have encouraged a resurgence of domestic petro-chemical production and other industries reliant upon natural gas as a feedstock. In addition, the development of liquefied natural gas (LNG) facilities and Mexican exports are opening up higher priced global markets for domestic natural gas supplies.

Infrastructure – New pipeline and storage facilities will be required to provide market accessibility, reliability and integrity. Until recent years, the predominant flow of natural gas has been from the Midcontinent, Gulf Coast, Rockies and Texas regions across the Midwest towards the Northeast. The developments in large gas production in the Marcellus and Utica shale reserves in the Northeast have created a dramatic shift in flow. Changes in the interstate pipeline system will occur as the supply pool for the Northeast grows and strands gas supplies. Natural gas will be directed toward the growing demand from: the petro-chemical industry in the Southeast, gas-fired generation throughout the Midwest, and East, and LNG exports in the Gulf Coast.

Price - Supplies of natural gas are expected to remain robust and will encourage the growth of industrial demand, gas-fired generation and global exports. Long-term, prices are expected to remain relatively low. However, over the next ten years, regional price dislocations may occur as gas infrastructure struggles to keep pace with the changing gas supply and demand.

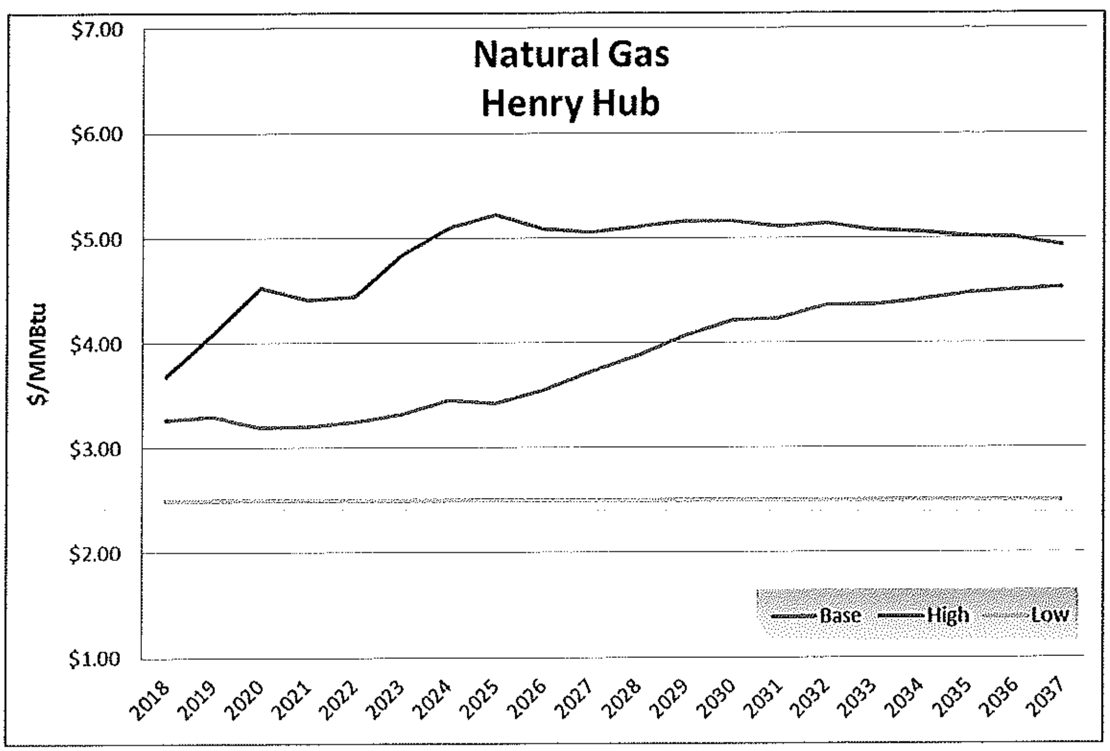
Natural Gas Price Assumptions

To develop our range of assumptions for natural gas prices, Ameren Missouri consulted its internal natural gas market experts. Several external expert sources of natural gas price projections have been reviewed in the development of our natural gas price assumptions. These sources include: Wood Mackenzie, PIRA, BTU Analytics, EIA , and the Nymex Henry Hub market prices. These research services, along with internal market knowledge of the natural gas industry, have helped to frame the long-term assumptions used and to provide context based on the drivers of the market. Based upon our assessment of the market fundamentals at this time and our long-term market expectations, the Company has developed assumptions for future prices for natural gas that are represented by the price levels shown in Table 2.5 and Figure 2.3.

Table 2.5 Natural Gas Price Assumptions

Real Gas 2016 $										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
High	$3.69	$4.09	$4.52	$4.41	$4.44	$4.84	$5.10	$5.23	$5.09	$5.05
Base	$3.27	$3.30	$3.20	$3.21	$3.25	$3.32	$3.46	$3.42	$3.55	$3.72
Low	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
High	$5.10	$5.15	$5.16	$5.11	$5.14	$5.08	$5.05	$5.01	$5.00	$4.93
Base	$3.89	$4.07	$4.21	$4.24	$4.35	$4.36	$4.41	$4.48	$4.50	$4.53
Low	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50

Figure 2.3 Natural Gas Price Assumptions



2.5.2 Coal Market[4]

Our development of long term coal price assumptions includes a review of the main drivers that most affect coal production and consumption for electric generation. This process was centered on those drivers most directly affecting Powder River Basin (PRB) coal given that the vast majority of our current and expected coal supply will be sourced from this basin. Overall U.S. coal supply is expected to be in the range of 700-850 million tons per year over the next 20 years. This is down from the recent past of one billion tons but is comparable to the 2016 volume of approximately 800 million tons. However, it is anticipated that PRB and Illinois Basin coals will gain a slightly wider market share as the other, less economical, US coal basins contract due to competition with energy sources like natural gas and renewables.

Coal Price Drivers

The long-term demand for PRB coal has been affected by low natural gas prices and increasing natural gas supply along with declining production from eastern U.S. coal fields, Central Appalachia and Northern Appalachia. PRB demand and pricing continues to be influenced by environmental regulations, transportation costs, and emission allowance markets. Export markets could also impact PRB demand in the future. Potential increases in exports of Appalachian and Illinois Basin coals will be driven by global economic strength and competition from other seaborne suppliers. U.S. coal exports represent the swing supply into the global market. Increased U.S. coal demand created by exporting domestic coal would likely be backfilled by PRB and other Illinois Basin coals.

PRB coal prices and production may vary as a result of any potential actions taken by the U.S. President and appointed officials during the next four years. This could include; changes in natural gas fracturing/production, halting or weakening open environmental rules, phasing out subsidies for renewable energy, changes in coal plant retirement schedules and reducing federal severance, royalties and tax rates on coal leases. An example of this kind of policy change includes the current administration's decision to drop out of the Paris Climate Agreement.

Several factors will contribute to volatile and likely higher PRB production costs going forward including the following:

- Strip ratios (overburden vs. coal seam) are expected to increase
- Government regulations continue to increase reclamation costs including coal producers potentially having to insure payment of future reclamation costs ("self-insurance" may be more limited in the future)

[4] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

- Severance taxes and coal lease fees (moratorium on federal coal leases as of 2016)
- Cost of materials, supplies and capital equipment such as diesel fuel, explosives & haul trucks
- Haul distances from coal pit to load-out are expected to increase
- Eventual interference with the railroad mainline

As mining progresses from east to west in the PRB, the coal seams dive deeper such that strip ratios will increase by 25% or more over the next 20 years. The western progression also infringes upon the railroad mainline such that mines will be faced with the decision to either "leap over" the railroad and essentially start up a new mine or move the rail lines onto reclaimed property and continue the mining progression. This will affect the PRB mines on the "Joint Line" (served by both the BNSF and the UP railroads) at varying timeframes over the planning horizon. The exception is the Antelope Mine, which is already located to the west of the Joint Line.

Coal prices may vary from the forecast due to the drivers mentioned above but are not limited to those drivers alone. Examples of other drivers that may impact coal prices are new mining, generation or environmental technology, changes in the electric grid and load loss/growth.

Given our current plan to meet emission compliance for SO_2 standards is to utilize installed environmental controls and burn predominately ultra-low sulfur coal (typically considered 0.55 lb SO_2/MMBtu or less) our analysis explicitly assumes this in the development of market prices for delivered coal to the Ameren Missouri energy centers. Long term supply of ultra-low sulfur PRB coal is expected to be 200-350 million tons per year. Such supply range for this product will be driven by coal retirements over the planning horizon and a mix of scrubbed versus unscrubbed coal plants to balance the needs and supply for ultra-low sulfur coal.

Coal Price Assumptions

In the development of the coal price forecasts for use in the 2017 IRP the Ameren Missouri fuels team shaped low, base and high long-range forecasts for PRB coal delivered to our existing coal-fueled Energy Centers. This process included an assessment of current and future expectations of PRB coal prices (FOB at the mine) rail transportation contracts (including diesel fuel surcharges) for delivery to each of our coal-fueled Energy Centers. Next, coal price projections from several outside services including Ventyx, PIRA, Wood Mackenzie, Energy Ventures Analysis Inc., US Energy Information Administration (EIA) and SNL were analyzed along with market-based forward curves to produce PRB low, base and high forecasts. The coal price forecasts for low, base and high coal prices are shown in Table 2.6

Table 2.6 Delivered Coal Prices ($/Ton) **

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2.5.3 Nuclear Fuel Market[5]

Nuclear Fuel Price Drivers

Ameren Missouri relied on UxC for nuclear fuel forecasts as we have for prior IRP analyses. Uxc provided annual price forecasts through 2030 for uranium (U3O8), conversion (UF6), and enrichment (SWU), front-end fuel components. It used the same approaches with each of the components. However, UxC forecasted spot prices for uranium, while it forecasted base prices for a new term contract for conversion and enrichment. The UxC price forecasts are generated by considering both market fundamentals (supply and demand) as well as an examination of short-term market behavior on the part of speculators and others that can exacerbate price trends set in motion by underlying supply and demand.

Fundamental analysis addresses the level of prices needed to support new production as well as the supply/demand balance in the long-term market. This analysis captures the pressure placed on available long-term supplies and the degree of competition that exists for long-term contracts, which gives an indication of the relative pricing power of producers. The fact that the published long-term price is well above marginal costs

[5] 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(A); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(D); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

attests to the situation where a simple marginal cost price analysis does not necessarily capture the current market dynamics at any point in time.

As it has before, UxC continues to focus on the demand for production, which takes total requirements and nets out secondary supplies such as Highly Enriched Uranium (HEU) feed to derive the underlying need for production. UxC also focuses on the expected balance of supply and demand in the spot market, since we are forecasting a spot price for uranium and conversion. Here, the role of speculators and financial interests become more important as they can represent additional demand. Financial interests may accumulate inventories, thus adding supply to the spot market.

Even more so than the long-term price, the spot price can vary considerably from production costs because it is an inventory-driven price. Ultimately, spot prices are linked to a production cost-based price since an excess or shortage of production causes inventories to rise or fall, respectively, and this in turn causes changes in the spot price, which affects prices received by producers by virtue of it being referenced in long-term contracts.

Nuclear Fuel Price Assumptions

Ameren Missouri uses the nuclear fuel cycle component price forecasts of the Ux Consulting Company (UxC). UxC was used in this role previously for the 2008, 2011, and 2014 IRPs. The Surfnonline model by HTH Associates is used by Ameren Missouri for Callaway 1 and is also used with modified engineering specifications for the fuel type associated with the AP1000 nuclear power unit. Figure 2.4 shows the low, base and high nuclear price forecasts for a new nuclear unit.

Figure 2.4 Nuclear Fuel Price Forecasts**

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Each scenario is then assigned an individual probability basis that is related to the likelihood of the associated assumptions. The probability weighting is assigned on a year-by-year basis for uranium, while a single probability weighting is assigned for all years for conversion and enrichment.

2.5.4 Electric Energy Market

Ameren Missouri continues to be a market participant within the MISO markets. We purchase energy and ancillary services to serve our entire load from the MISO market and separately sell all of our generation output and certain ancillary services into the MISO market. The vast majority of load and generation is settled in the day ahead market. Only those deviations from the day ahead awards are cleared in the real time market. MISO also operates a capacity market, and while clearing for capacity does impose certain obligations upon capacity resources (e.g., generators) including a must-offer obligation, the sale (or purchase) of capacity in the MISO market does not convey any rights or obligation to energy from the associated resource.

In actual market operation, each individual generator and the aggregate load receives a unique price for each hour in both the day ahead and the real time markets. The model, however, uses the same price for generation and load, given that Ameren Missouri receives an allocation of auction-revenue rights from the MISO based on its historical use of the system, which has generally proven to be sufficient to mitigate the price congestion between Ameren Missouri's base load generation and its load.

To develop power price assumptions for the planning horizon and to account for price uncertainty and the interrelationships of key power market price drivers, Ameren Missouri has used a scenario modeling approach as described in section 2.7.

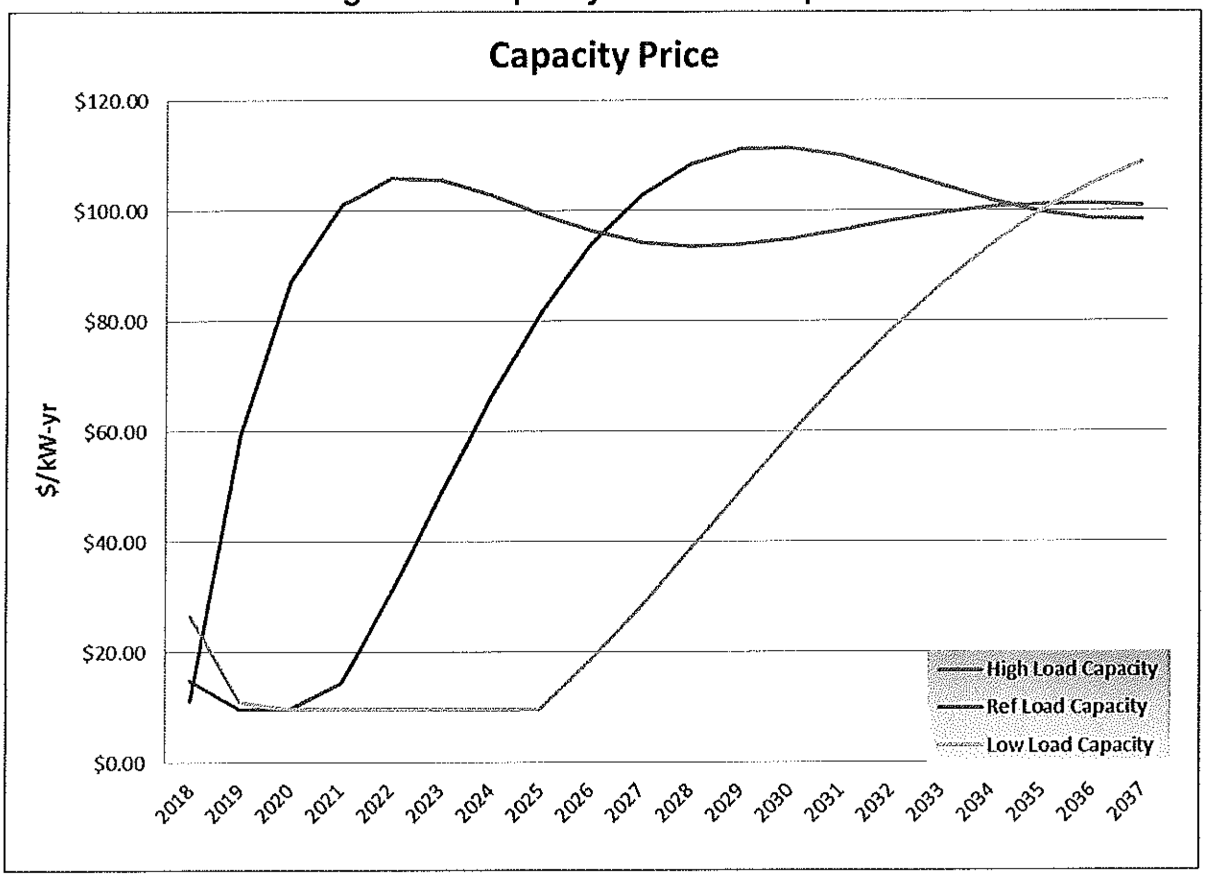
2.5.5 Power Capacity Market

The capacity price forecast used in the 2017 IRP is based on a fundamental supply-demand relationship developed by running software provided by Ventyx and commonly referred to as "Strategic Planning" or "MIDAS". This detailed simulation modeling software provides an economic dispatch production cost projection that utilizes load, fuel price, power production capabilities and many other assumptions and projections. To provide the detailed data needed to populate the Strategic Planning model for purposes of developing a forward capacity forecast, Ventyx provides a service that incorporates all the assumptions that are used in their Power Reference Case. The Ventyx Power Reference Case is an iterative integrated process used to determine the impacts that capacity additions and retirements have on power markets. This process also considers the renewable energy expansion necessary to meet state Renewable Portfolio Standard targets but no federal renewable standard.

This software has the ability to develop a value for capacity based on meeting reserve margins requirements as set by the ISO. The model determines if new capacity needs to be built to meet reserve margin requirements and will add generation to regions to meet that need. Once the new generation has been added to the region's resource mix the value of capacity is set at the full cost of the generation minus the energy revenue it receives from the market.

Figure 2.5 shows the capacity price curves produced by MIDAS and used for integration and risk analysis as discussed in Chapter 9. The three capacity price curves correspond to the base, high and low load growth scenarios discussed previously as load growth was found to be the primary driver of capacity prices.

Figure 2.5 Capacity Price Assumptions



2.5.6 Renewable Energy Standard

One of the considerations in developing alternative resource plans for Ameren Missouri is the need to comply with the Missouri Renewable Energy Standard (RES), which was passed into law by a voter initiative in November 2008. This standard requires all invester owned regulated Missouri utilities to supply an increasing level of energy from renewable energy resources or acquire the equivalent renewable energy credits (RECs) while subject to a rate impact limitation of 1% as determined by rules set by the Missouri Public Service Commission. The target levels of renewable energy, determined by applying increasing percentage to total retail sales, are:

- 2% in 2011-2013
- 5% in 2014-2017
- 10% in 2018-2020
- 15% starting in 2021

Additionally, a solar carve-out provision is included in the standard and requires that at least 2% of renewable energy be sourced from solar generation. This provision can also be met with the purchase of solar RECs or SRECs. Our analysis of RES compliance is presented in Chapter 9.

2.6 Environmental Regulations

With increasingly stringent regulation of coal-fired power plants, including continuing efforts to regulate GHG emissions, the effects of these regulations on the electric energy market must be considered in assessing potential resource options and portfolios. More specifically, the environmental statutes and regulations include:

- Clean Air Act (CAA)
    - National Ambient Air Quality Standards (NAAQS)
        - Implementation of ambient standards for ozone, PM (particulate matter) and sulfur dioxideCross State Air Pollution Rule (CSAPR)
    - Maximum Achievable Control Technology (MACT) Standards
        - Mercury and Air Toxic Standards (MATS)
    - Section 111
        - Section 111(b) GHG New Source Performance standards for new, reconstructed and modified coal and gas fired power plants
        - Section 111(d) GHG New Source Performance standards for existing coal fired power plants
    - New Source Review
    - Regional Haze
- Clean Water Act (CWA)
    - Section 316a regulations covering thermal discharges
    - Section 316b regulations covering water intake structures
    - Wetlands/Waters of the U.S.
    - Spill Prevention Control & Countermeasures (SPCC)
    - Effluent Limitations Guidelines Revisions (ELGs)
- Safe Drinking Water Act
- Solid Waste Disposal Act

- Coal Combustion Residuals (CCR)
  - Ash Pond Closure Initiatives
- Resource Conservation and Recovery Act (RCRA)
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)
- Superfund Amendments Reauthorization Act (SARA)
- Toxic Substances Control Act (TSCA)
  - PCB regulations
  - Implementation of the recent amendments to TSCA under the Frank T. Lautenberg Chemical Safety for the 21st Century Act
- Emergency Planning & Community Right-To-Know Act (EPCRA)

A more detailed discussion of enviromental regualtions can be found in Chapter 5. In addition to this list, the potential continues for new and evolving laws and regulation to create a changing landscape for investment decisions over the planning horizon. While the effects of these current and potential future regulations are complex, a primary consideration continues to be how they will affect power prices. Our process established that changes in power markets would most significantly be impacted through the degree and timing of coal plant retirements across the entire Eastern Interconnect.

In addition to the existing and future regulations outlined above, we must also consider potential actions with respect to climate policy and regulation of GHG emissions beyond the regulation that was finalized by the EPA in the form of its Clean Power Plan (CPP). To help frame the ongoing possibilities for carbon policy and regulation of GHG emissions, we examined reports from several research and consulting companies, such as IHS Cera, Synapse Energy Economics, Inc along with MISO studies of the CPP. We also reviewed the 2016 EIA reference case along with their alternative Clean Power Plan cases.

We identified three general paths forward by which GHG policy would be implemented through any of these paths;

- CPP struck down and carbon regulations become a state by state patchwork
- Carbon reduction goals move forward in a CPP form or some other structure that achieves similar carbon reductions
- A more restrictive carbon future that incorporates added renewables, energy efficency and increasing enviromental regulation pressures provide for a more carbon limited case

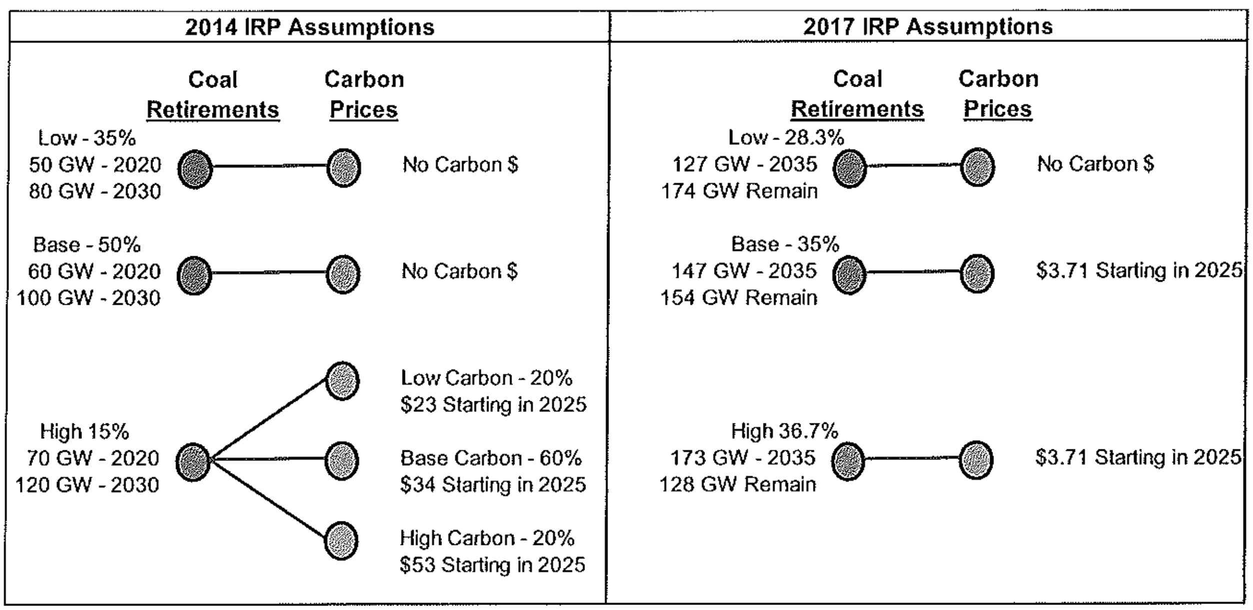
This framework provided a theme of discussions for our internal experts to identify the probable ranges of coal retirements and carbon prices that define our scenarios.

Through this process an updated set of assumptions was developed to reflect environmental policy effects on coal retirement expectations, as well as the timing, magnitude and probability of an explicit price on carbon dioxide emissions.

Coal Plant Retirements[6]

Our power price scenario model, described in section 2.7, relies on Ventyx' s national dataset. This dataset includes assumptions for expected coal plant retirements spanning the 20-year time frame of the IRP and was used as a starting reference. This dataset includes plant closures based on company announcements and Ventyx's analysis given current laws and regulations at the time of publishing the dataset used in the study. This set of retirements was reviewed in light of the current and expected regulations over the planning horizon. In order to reflect the range of possible environmental futures that represent the planning horizon, our previous coal plant retirement assumptions for three levels – low, base, and high – were updated based on review and multiple discussions with internal experts involved in environmental regulation and policy. Figure 2.6 shows the changes made for the 2017 IRP.

Figure 2.6 Coal Retirement Assumptions



Carbon Dioxide Emissions Prices[7]

In addition to coal plant retirements, an update to an explicit carbon price expectation and the timing of this price was reviewed. The price of carbon dioxide emissions is assumed to be zero in all years prior to 2025. The development of a carbon price

[6] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.060(5)(C)

[7] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(5); 4 CSR 240-22.040(5)(D); 4 CSR 240-22.060(5); 4 CSR 240-22.060(5)(C); 4 CSR 240-22.060(5)(H); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

included a review of several approches to projecting a carbon price including Synapse, IHS-Cera, EIA 2016, and PIRA. The approach that aligned most closely with the views of our subject matter experts was that of the IHS-Cera Rivalry scenario. Expectations for this scenerio included a greater role for natuarl gas, renewable energy, energy efficiencey programs and an overall evolution of energy technologies. The uncertainty of these factors led to many possible paths with which the chosen carbon price would be compatible. We have assumed a high level of coal plant retirements in conjunction with an explicit price on carbon dioxide emissions given the expectation that this carbon price will result in more restrictive operations of coal facilities. Table 2.7 shows the values used in the current IRP analysis.

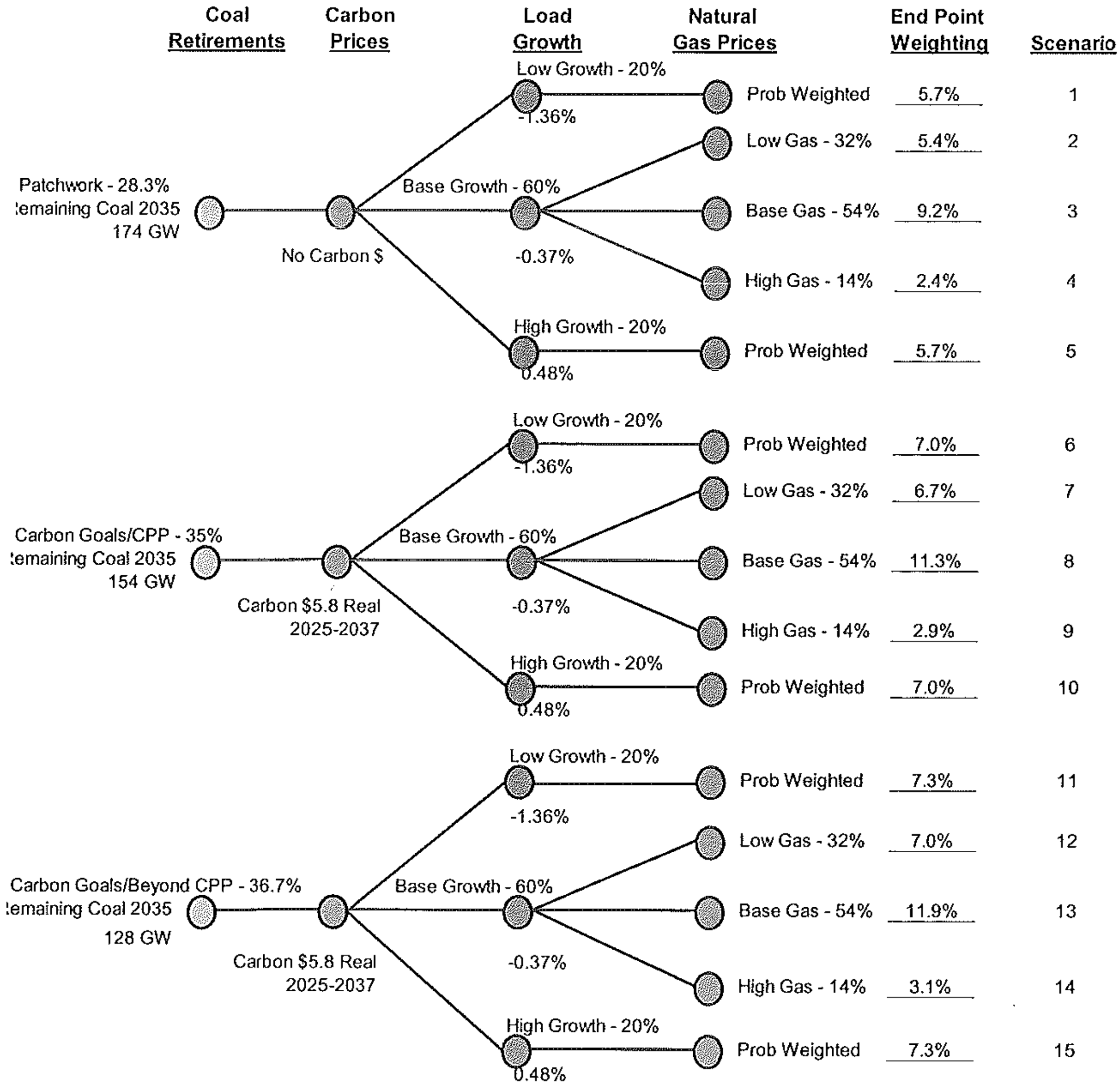
Table 2.7 Carbon Dioxide Emissions Price Assumptions

	2016 $/Ton Real			Nominal		
	Low Case	Mid Case	High Case	Low Case	Mid Case	High Case
2025	$0.00	$3.11	$3.11	$0.00	$3.71	$3.71
2026	$0.00	$3.42	$3.42	$0.00	$4.17	$4.17
2027	$0.00	$3.77	$3.77	$0.00	$4.68	$4.68
2028	$0.00	$4.15	$4.15	$0.00	$5.26	$5.26
2029	$0.00	$4.57	$4.57	$0.00	$5.91	$5.91
2030	$0.00	$5.03	$5.03	$0.00	$6.64	$6.64
2031	$0.00	$5.54	$5.54	$0.00	$7.46	$7.46
2032	$0.00	$6.11	$6.11	$0.00	$8.39	$8.39
2033	$0.00	$6.73	$6.73	$0.00	$9.43	$9.43
2034	$0.00	$7.42	$7.42	$0.00	$10.60	$10.60
2035	$0.00	$8.18	$8.18	$0.00	$11.91	$11.91
2036	$0.00	$9.01	$9.01	$0.00	$13.39	$13.39
2037	$0.00	$9.93	$9.93	$0.00	$15.05	$15.05

2.7 Price Scenarios

Power prices are influenced primarily by electric demand, the mix of available generation resources, and natural gas prices. Using our assumptions for load growth, coal retirements, carbon prices, and natural gas prices, we developed scenarios based on various combinations of these assumptions. The development of scenario modeling is best represented by a probability tree diagram and the associated probability of each branch of the tree. Each branch of the tree is used to represent a combination of dependent input variables that can have an impact on plan selection. In order to focus on those combinations with the greatest influence on alternative resource plan performance, potential branches that would be characterized by a significantly low probability of occurrence are collapsed to provide a simplified yet still robust set of possible branches. This process provides for a wide range of potential future combinations with which we can analyze alternative resource plan performance and risk. Figure 2.7 shows the final scenario tree.

Figure 2.7 Final Scenario Tree



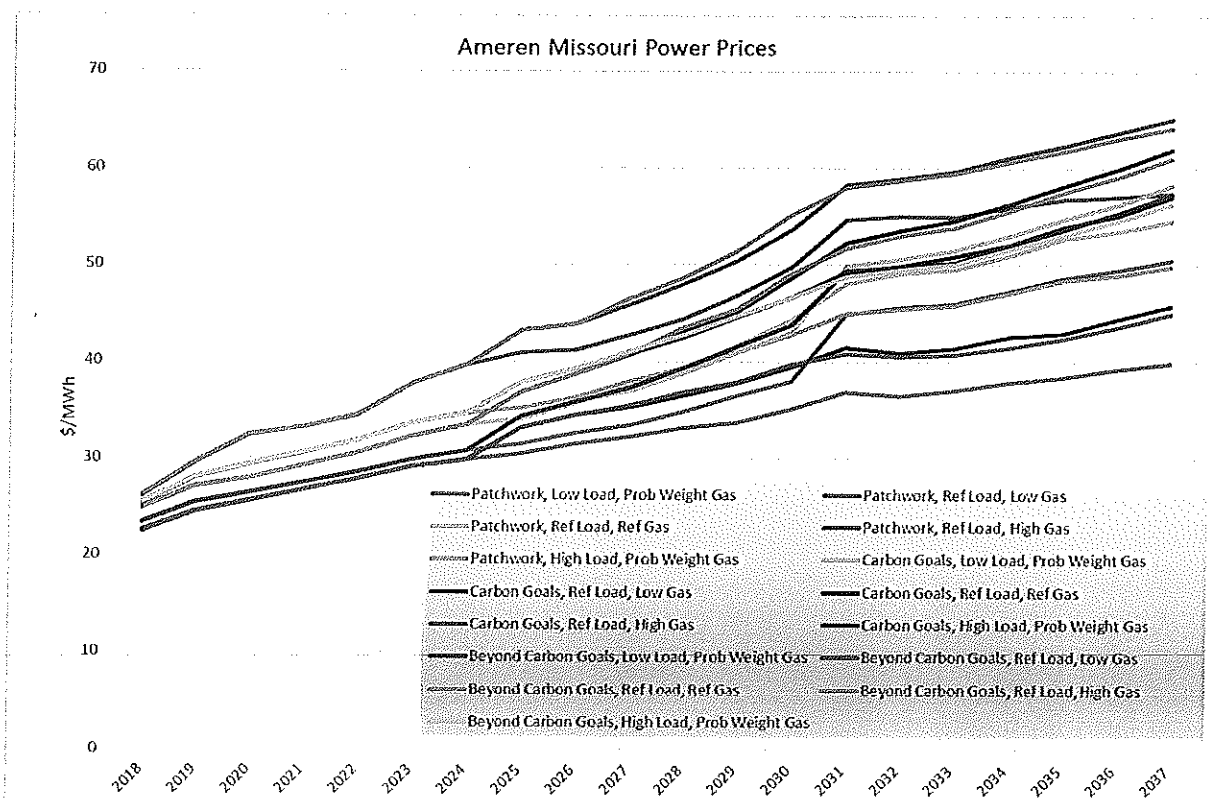
Electric Power Prices[8]

To support our analysis of alternative resource plans, as described in Chapter 9, we developed forward price forecasts at the Indy Hub using modeling software provided by Ventyx and commonly referred to as "Strategic Planning" or "MIDAS". This is the same model used to develop capacity prices and utilizes the same detailed simulation modeling and database setup to develop power prices. To ensure that a range of possible future power prices were incorporated, those inputs determined to be uncertain and impactful enough to warrant the need for a range of possible inputs were varied. These inputs were;

- Long-term assumptions for load growth
- Natural gas prices
- Coal plant retirements representing the impacts of environmental regulation
- An explicit price on carbon dioxide emissions in some cases

These inputs were varied in the model from the Ventyx reference case provided. This process produced values based on the probability tree shown in Figure 2.7. The results of this modeling for each branch yield different power price futures, which are shown in Figure 2.8 after basis adjustment as explained in the following section.

Figure 2.8 Scenario Power Prices



[8] 4 CSR 240-22.060(5)(G); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B

Power Price Shaping

It is necessary to convert the around-the-clock (ATC) Power Prices for the Indiana Hub (obtained in the manner explained above) into 8,760 hourly prices for each year by scenario in order to achieve reasonable results from the RTSim production cost model, which uses an hourly dispatch to model the generation system. For this IRP, Ameren Missouri has used the same methodology for shaping block prices into hourly prices as it uses in its fuel budgeting modeling.

Before such shaping can occur, the ATC Power Prices for the Indiana Hub must first be basis adjusted for time (real-time to day-ahead (DART)) and for location (INDY Hub to Ameren Missouri generation).

Once ATC prices have been basis adjusted, they are broken down into monthly block prices for each year in each scenario utilizing historical ratios of individual months to the annual ATC price, and peak blocks (5x16, 2x16 and 7x8) within a month to that month's price. These block prices by month are then shaped into hourly prices utilizing the 2011 day-ahead price curve applicable to Ameren Missouri's base load generators. 2011 was selected as the reference year to maintain consistency with use of the same year for load shaping.

These power prices were used in the analysis of alternative resource plans described in Chapter 9.

2.8 Compliance References

2013/2014 MISO Planning Resource Auction Results:

Local Resource Zone (LRZ)	Z1 (MN, ND, Western WI)	Z2 (Eastern WI, Upper MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	System
Planning Reserve Margin Requirements (PRMR)	17,693.4	13,362.9	9,343.1	10,733.9	9,000.2	19,320.3	22,702.3	102,156.1
Netted DR/EER*	1197.1	728.7	528.8	112.3	0	1191.7	781.6	4,540.2
Adjusted PRMR	16,387.3	12,573.2	8,767.6	10,612.1	9,000.2	18,023.3	21,850.3	97,214.0
Offer								70,412.1
FRAP[1]								34,959.3
Offer + FRAP[1]								105,371.4
Offer Cleared + FRAP[1]								97,214.0
Local Clearing Requirement (LCR)	15,707.7	10,326.2	6,796.4	5,231.9	5,490.7	14,283.5	21,055.0	N/A
Capacity Import Limit (CIL)	4,085.0	4,144.0	3,717.0	6,614.0	5,035.0	6,838.0	4,576.0	N/A
Capacity Export Limit (CEL)	1,416.0	1,766.0	1,612.0	2,230.0	1,616.0	3,432.0	4,306.0	N/A
Auction Clearing Price ($/MW-Day)	1.05	1.05	1.05	1.05	1.05	1.05	1.05	

* Planning Reserve Margin and Transmission losses are not applied to Netted Demand Response (DR) and Energy Efficiency Resources (EERs) in the PRMR calculation.

[1] FRAP = Fixed Resource Adequacy Plan

2014/2015 Planning Resource Auction (PRA)

MISO completed its Annual Planning Resource Auction for Planning Year 2014-2015 based on Market Participant Offers submitted between March 27 and 31, and posted final results on April 14, 2014

- This was the second full-year PRA under the Module E-1 Tariff. MISO completed a partial year, Transitional PRA prior to MISO South entities integrating in December 2013.
- The Auction produced three clearing prices:
  1. Local Resource Zone (LRZ) 1 cleared at $3.29 per MW-Day as its Zonal Capacity Export Limit bound
  2. LRZs 2-7 cleared at $16.75 per MW-Day
  3. LRZs 8-9 cleared at $16.44 per MW-Day as constraints related to intra-RTO dispatch ranges bound between the MISO South and the MISO Central/North Regions
- A total of 136,912 MW of Planning Resources were cleared to meet the MISO's resource adequacy requirements. This includes 124,556 MW of Generation Resources, 3,743 MW of Behind-the-Meter Generation (BTMG), 5,457 MW of Demand Response (DR), and 3,156 MW of External Resources (ER).
- The MISO Planning Reserve Margin Requirement (PRMR) increased by 2,475 MW to 136,912 MW from 2013-14 PRA due to; an increase in Coincident Peak Forecast, an increase in Planning Reserve Margin (PRM) from 6.2% to 7.3%, and, an increase in Zone 8's PRMR as the Zonal Local Clearing Requirement was greater than the Zonal PRMR.
- Excess Zonal Resource Credits of 12,201 MW remained after meeting the PRMR, up from 8,659 MW in 2013-14 PRA, but down slightly from the MISO South Transitional PRA, 12,615 MW.

2014/2015 MISO Planning Resource Auction Results

LRZ	Z1 (MN,ND, Western WI)	Z2 (Eastern WI, Upper MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	Z8 (AR)	Z9 (LA, MS, TX)	System
Demand Forecast	16,540	12,347	8,757	9,680	8,106	17,629	20,791	7,363	22,999	124,212
PRMR (based on CPF)	18,236	13,504	9,628	10,616	8,884	19,404	22,998	8,043	25,224	136,537
LCR	15,070	11,739	8,971	8,879	5,002	15,457	21,293	8,417	24,080	N/A
Effective PRMR	18,236	13,504	9,628	10,616	8,884	19,404	22,998	8,417	25,224	136,912
Total Offer Submitted	7,045	2,879	9,520	11,370	387	17,985	15,190	9,406	25,966	99,747
Total FRAP applied	12,620	12,352	391	874	7,722	1,846	8,449	397	2,372	47,022
Offer Cleared + FRAP	18,522	14,358	9,787	9,316	8,109	19,551	22,627	8,582	26,059	136,912
Import Limit	4,347	3,083	1,591	3,025	5,273	4,834	3,884	1,602	3,585	N/A
Export Limit	286	1,924	1,875	1,961	1,350	2,246	4,517	3,080	3,616	N/A
ACP ($/MW-Day)	3.29	16.75	16.75	16.75	16.75	16.75	16.75	16.44	16.44	N/A

MISO

Participation by Resource Type (System-wide)

Planning Resource Type	UCAP	Unconverted	Fixed Resource Plans	OFFER	Cleared	ZRC Balance
Generation	138,668	3,480	42,394	90,645	82,162	10,632
Behind the Meter Generation	4,071	59	2,141	1,693	1,602	270
Demand Response	5,750	3	1,449	4,298	4,008	290
External Resources	4,238	73	1,038	3,111	2,117	1,009
Energy Efficiency	0	0	0	0	0	0
Total	152,727	3,615	47,022	99,747	89,890	12,201
%UCAP	100%	2%	31%	65%	59%	8%

Appendix - Acronyms

ACP - Auction Clearing Price ($/MW-Day)
CEL - Capacity Export Limit (MWs)
CIL - Capacity Import Limit (MWs)
CPF – Coincident Peak Forecast (MW)
FRAP - Fixed Resource Adequacy Plan (MWs)
LCR - Local Clearing Requirement (MWs)
LRZ - Local Resource Zone
MP - Market Participant
PRA - Planning Resource Auction
PRM - Planning Reserve Margin
PRMR - Planning Reserve Margin Requirement (MWs)
SFT – Simultaneous Feasibility Test
TPRA – Transitional Planning Resource Auction
UCAP - Unforced Capacity (MWs)
ZRC - Zonal Resource Credit (MWs)

Ex. AA-D-13

2015/2016 Planning Resource Auction Results

April 14, 2015

Executive Summary

Ex. AA-D-13

- **MISO successfully completed its third annual Planning Resource Auction**
- **The MISO region has adequate resources to meet its Planning Reserve Margin Requirements for the 2015/2016 planning year.**
  - Zones 1-3 and 5-7 cleared at $3.48/MW-day
  - Zone 4 (much of Illinois), cleared at $150.00/MW-day
  - Zones 8-9 (MISO South), cleared at $3.29/MW-day

MISO

Auction Inputs and Considerations

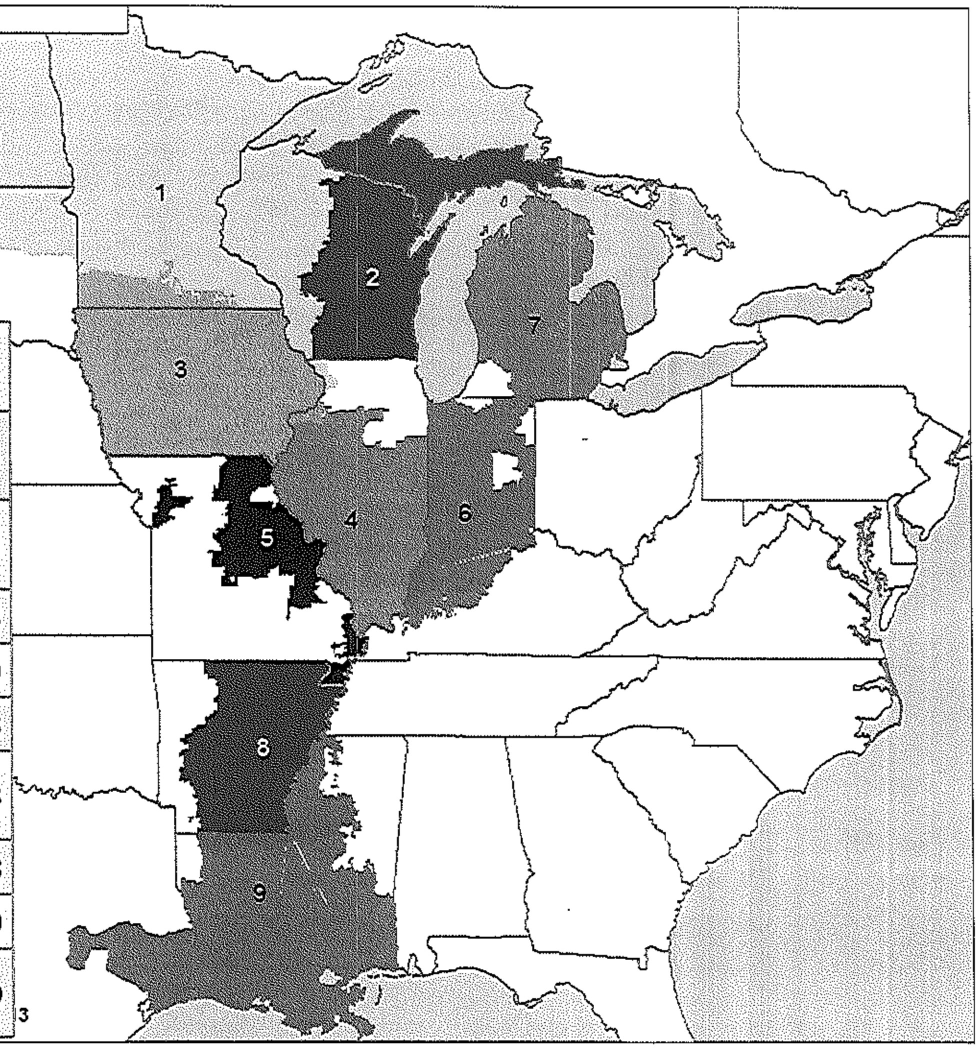
Ex. AA-D-13

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region as a whole subject to the following:
  - MISO-wide reserve margin requirements
  - Zonal capacity requirements (Local Clearing Requirement)
  - Zonal transmission limitations (Capacity Import/Export Limits)
  - If applicable, Sub-Regional contractual limitations such as between MISO's South and Central/North Regions
- The zonal capacity requirement must be met with Resources located within the zone
- The MISO-wide reserve margin requirement is shared among the zones, and zones may import capacity to meet this requirement
- The Independent Market Monitor reviews the auction results for physical and economic withholding

2015/2016 Auction Clearing Price Overview

AA-D-13

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$3.48
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$3.48
3	ALTW, MEC, MPW	$3.48
4	AMIL, CWLP, SIPC	$150.00
5	AMMO, CWLD	$3.48
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE	$3.48
7	CONS, DECO	$3.48
8	EAI	$3.29
9	CLEC, EES, LAFA, LAGN, LEPA, SMEPA	$3.29



Next Steps: Auction Output and Settlements

- **Key outputs from the auction are:**
  - A commitment of capacity to the MISO region, including performance obligations and
  - The capacity price (Auction Clearing Price) for each zone
- **This price drives the settlements process**
  - Load pays the auction clearing price for the zone in which it is physically located
  - Cleared capacity is paid the auction clearing price for the zone where it is physically located
    - External resources are paid the price of the zone where their firm transmission service crosses into MISO
- **When price separation between zones occurs, a zone's use of resources located outside of its boundaries will result in MISO over collecting auction revenues**
  - This over-collection is allocated, per the MISO tariff, to the Load within the zone(s)

MISO

2015/2016 Planning Resource Auction Detailed Results

Ex. AA-D-13

Local Resource Zone	Z1 (MN, ND, Western WI)	Z2 (Eastern WI, Upper MI)	Z3 (IA)	Z4 (IL)	Z5 (MO)	Z6 (IN, KY)	Z7 (MI)	Z8 (AR)	Z9 (LA, MS, TX)	SYSTEM
CPDF (Coincident Peak Demand Forecast)	16,525	12,429	8,876	9,518	8,176	17,592	20,522	7,424	23,035	124,097
PRMR (Planning Reserve Margin Requirement)	18,321	13,566	9,768	10,420	8,910	19,409	22,678	8,118	25,170	136,359
LCR (Local Clearing Requirement)	15,982	12,332	8,695	8,852	6,527	14,677	21,442	7,850	23,609	N/A
Total Offer Submitted	4,867	3,071	5,922	11,156	7,926	14,832	14,103	9,562	26,193	97,632
Total FRAP (Fixed Resource Adequacy Plan)	14,494	11,817	4,113	838	0	4,853	9,456	397	2,261	48,229
Offer Cleared + FRAP	18,495	14,497	9,813	8,852	7,885	19,015	23,515	8,526	25,762	136,359
Import / (Export)	(175)	(931)	(45)	1,568	1,026	394	(837)	(408)	(592)	2,988
CIL (Capacity Import Limit)	3,735	2,903	1,972	3,130	3,899	5,649	3,813	2,074	3,320	N/A
CEL (Capacity Export Limit)	604	1,516	1,477	4,125	0	2,930	4,804	3,022	3,239	N/A
ACP (Auction Clearing Price) $/MW-Day	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	N/A

MISO

Ex. AA-D-13

Key Auction Takeaways: Auction Clearing Prices relative to key thresholds

	Zone 1 (MN, ND, Western WI)	Zone 2 (Eastern WI, Upper MI)	Zone 3 (IA)	Zone 4 (IL)	Zone 5 (MO)	Zone 6 (IN, KY)	Zone 7 (MI)	Zone 8 (AR)	Zone 9 (LA, MS, TX)
2014-2015 Auction Clearing Price (ACP)	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44
2015-2016 Auction Clearing Price (ACP)	**$3.48**	**$3.48**	**$3.48**	**$150.00**	**$3.48**	**$3.48**	**$3.48**	**$3.29**	**$3.29**
2015-2016 Reference Level	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79	$155.79
2015-2016 Conduct Threshold	$180.43	$180.65	$180.14	$180.53	$181.00	$180.45	$180.59	$179.45	$179.61
2015-2016 Cost of New Entry (CONE)	$246.41	$248.63	$243.48	$247.40	$252.05	$246.60	$248.03	$236.55	$238.22

*All values in $/MW-day

MISO

Key Auction Takeaways

Ex. AA-D-13

- Price differentials between 2014-15 and 2015-16 results were mainly driven by changes in market participant offers.
- The 2015 price in Zone 4 was also impacted due to the binding of the zonal capacity requirement to procure a certain amount of capacity with the zone (LCR)
  - This requirement for Zone 4 was substantially the same as in the 2014/2015 Auction.
- Zones 8 and 9 cleared at a lower price than the other zones due to the south to north sub-regional power balance constraint binding at 1,000 MW.

Conclusions

Ex. AA-D-13

- **MISO successfully completed its third annual Planning Resource Auction, demonstrating that the MISO region has adequate resources to meet capacity requirements for the 2015/2016 planning year.**
  - Zones 1-3 and 5-7 cleared at $3.48/MW-day
  - Zone 4 (much of Illinois), cleared at $150.00/MW-day
  - Zones 8-9 (MISO South), cleared at $3.29/MW-day

MISO

Acronyms

Ex. AA-D-13

- ACP - Auction Clearing Price ($/MW-Day)
- BTMG – Behind The Meter Generator
- DR – Demand Resource
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- CPDF – Coincident Peak Demand Forecast (MW)
- FRAP - Fixed Resource Adequacy Plan (MW)
- LCR - Local Clearing Requirement (MW)
- LOLE – Loss Of Load Expectation
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SFT – Simultaneous Feasibility Test
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- UCAP - Unforced Capacity (MW)
- ZDB – Zonal Deliverability Benefits
- ZRC - Zonal Resource Credit (MW)

MISO

MISO

2016/2017 Planning Resource Auction Results

April 15, 2016

Revised 4/15/2016 to Include Total Offer Submitted by Zone on Slide 8

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 135,483 MW
  - Zone 1 cleared at $19.72/MW-day
  - Zones 2-7 cleared at $72.00/MW-day
  - Zones 8-10 cleared at $2.99/MW-day

- Implemented FERC's Order in Docket ER16-833-000 that modified Reference Levels, Capacity Import Limits (CILs) and Local Clearing Requirements (LCRs)
- Regional generation supply is consistent with the 2015 MISO OMS Survey

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
  - MISO-wide reserve margin requirements
  - Zonal capacity requirements (Local Clearing Requirement)
  - Zonal transmission limitations (Capacity Import/Export Limits)
  - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions
- The MISO-wide reserve margin requirement is shared among the zones, and zones may import capacity to meet this requirement
- Multiple options exist for Load Serving Entities to demonstrate Resource Adequacy:
  - Submit a Fixed Resource Adequacy Plan
  - Utilize bilateral contracts with another resource owner
  - Participate in the Planning Resource Auction
- The Independent Market Monitor reviews the auction results for physical and economic withholding

Changes since PRA 2015/2016

- Tariff revisions approved in FERC Docket No. ER16-833-000 implemented, including increased CILs, decreased LCRs, and reduced Initial Reference Level to $0/MW-day

- Sub-Regional Export Constraint in the South to Midwest direction modified to reflect the Settlement Agreement

- LRZ 10 for the State of Mississippi established – No impact

- Other minor changes:
  - EPA RICE-NESHAP* regulations, which likely led to some additional retirements incremental to our OMS survey results
  - Allocation of Zonal Deliverability Benefit revised – pending FERC decision
  - Suspended units required to participate in the PRA – No impact

*Reciprocating Internal Combustion Engine National Emission Standard for Hazardous Air Pollutants

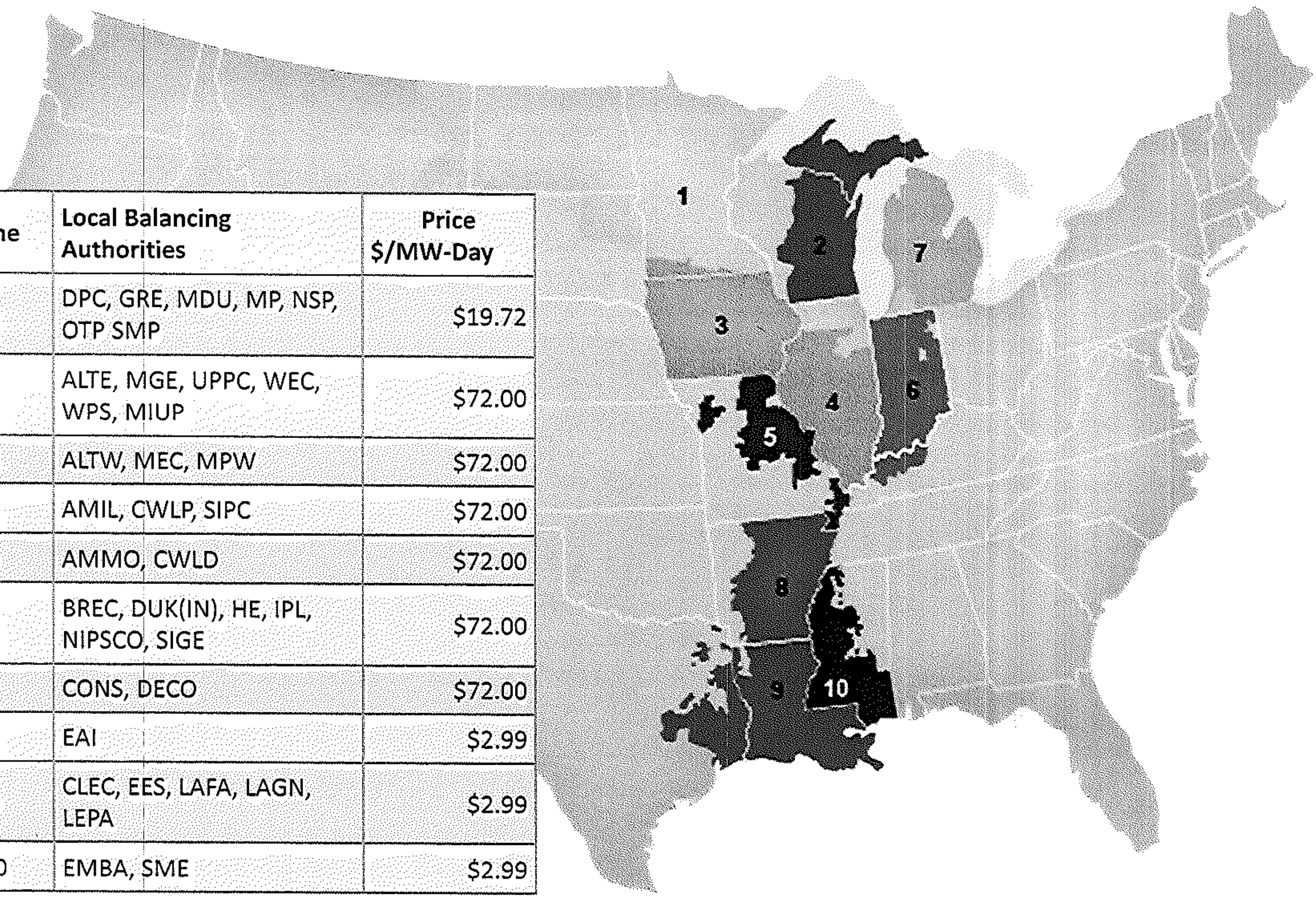
Auction Output and Settlements

- Key outputs from the auction are:
  - A commitment of capacity to the MISO region, including performance obligations and
  - The capacity price (Auction Clearing Price) for each Zone

- This price drives the settlements process
  - Load pays the Auction Clearing Price for the Zone in which it is physically located
  - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
    - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

2016/2017 Auction Clearing Price Overview

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$19.72
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$72.00
3	ALTW, MEC, MPW	$72.00
4	AMIL, CWLP, SIPC	$72.00
5	AMMO, CWLD	$72.00
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE	$72.00
7	CONS, DECO	$72.00
8	EAI	$2.99
9	CLEC, EES, LAFA, LAGN, LEPA	$2.99
10	EMBA, SME	$2.99



MISO

Auction Clearing Prices
$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44	N/A
2015-2016 ACP*	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	N/A
2016-2017 ACP*	**$19.72**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$72.00**	**$2.99**	**$2.99**	**$2.99**
Conduct Threshold	*$25.80*	*$26.06*	*$25.52*	*$25.93*	*$26.42*	*$25.85*	*$25.98*	*$24.76*	*$25.12*	*$24.60*
Cost of New Entry	*$258.00*	*$260.58*	*$255.15*	*$259.26*	*$264.19*	*$258.47*	*$259.81*	*$247.56*	*$251.21*	*$246.05*

- Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Conduct Threshold is $0 for a Generation Resource with a Facility Specific Reference Level

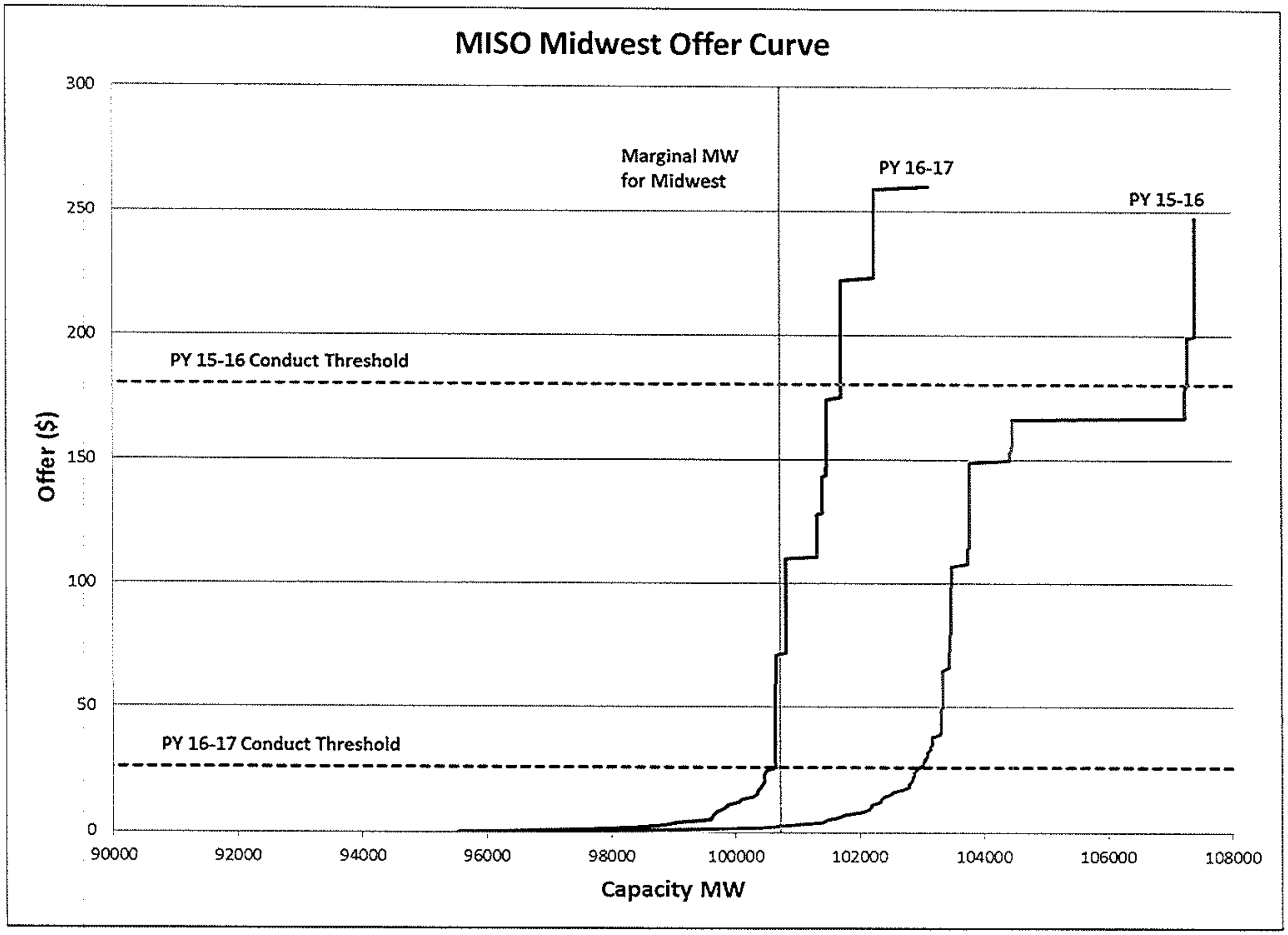
* Auction Clearing Price

2016/2017 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,185	13,589	9,879	10,375	8,518	18,750	22,406	8,178	20,713	4,891	135,483
Total Offer Submitted (Including FRAP)	19,430	14,903	10,138	11,371	7,926	18,398	21,615	10,587	20,257	6,899	141,524
FRAP	14,252	12,063	501	910	0	4,338	1,393	318	577	1,641	35,995
ZRC Offer Cleared	4,522	2,840	9,636	8,242	7,927	14,060	20,141	9,676	17,934	4,511	99,488
Total Committed (Offer Cleared + FRAP)	18,775	14,903	10,138	9,152	7,927	18,398	21,534	9,995	18,511	6,151	135,483
LCR	15,918	12,986	8,715	5,476	5,026	13,698	20,851	6,270	17,477	3,978	N/A
CIL	3,436	1,609	1,886	6,323	4,837	5,610	3,521	3,527	4,490	2,653	N/A
Import	0	0	0	1,224	592	352	872	0	2,202	0	5,240
CEL	590	2,996	1,598	7,379	896	2,544	4,541	2,074	1,261	1,857	N/A
Export	590	1,315	258	0	0	0	0	1,817	0	1,260	5,240
ACP ($/MW-Day)	$19.72	$72.00	$72.00	$72.00	$72.00	$72.00	$72.00	$2.99	$2.99	$2.99	N/A

MISO

Midwest Offer Curve 2015/2016 vs. 2016/2017



Next Steps

- Detailed results review at May 5 RASC
- Posting of PRA offer data 30 days after PRA conclusion – May 13

Acronyms

- ACP - Auction Clearing Price ($/MW-Day)
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- FRAP - Fixed Resource Adequacy Plan (MW)
- LCR - Local Clearing Requirement (MW)
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint

References

- Sub-Regional Export and Import Constraints discussed at the Supply Adequacy Working Group (SAWG)
  - October 29, 2015
  - December 3, 2015
  - February 4, 2016

Ex. AA-D-15

2017/2018 Planning Resource Auction Results

April 14, 2017

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 134,753 MW
  - Zones 1-10 cleared at $1.50/MW-day
  - Marginal resource is in Zone 1
  - Increased supply and lower demand in Midwest largely responsible for lower Auction Clearing Prices relative to last year
- Regional generation supply is consistent with the 2016 OMS-MISO Survey
- No mitigation for physical or economic withholding by the IMM

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
  - MISO-wide reserve margin requirements
  - Zonal capacity requirements (Local Clearing Requirement)
  - Zonal transmission limitations (Capacity Import/Export Limits)
  - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions

- The MISO-wide reserve margin requirement is shared among the Zones, and Zones may import capacity to meet this requirement

- Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:
  - Submit a Fixed Resource Adequacy Plan
  - Utilize bilateral contracts with another resource owner
  - Participate in the Planning Resource Auction

- The Independent Market Monitor reviews the auction results for physical and economic withholding

Auction Output and Settlements

- Key outputs from the Auction
  - A commitment of capacity to the MISO region, including performance obligations and
  - The capacity price (Auction Clearing Price) for each Zone
- This price drives the settlements process
  - Load pays the Auction Clearing Price for the Zone in which it is physically located
  - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
    - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

Changes since PRA 2016/2017

- Tariff revisions approved in FERC Docket No. ER17-806-000 exempting Demand Resources (DR), Energy Efficiency Resources (EER) and External Resources (ER) from Market Monitoring and Mitigation in the 2017-18 PRA

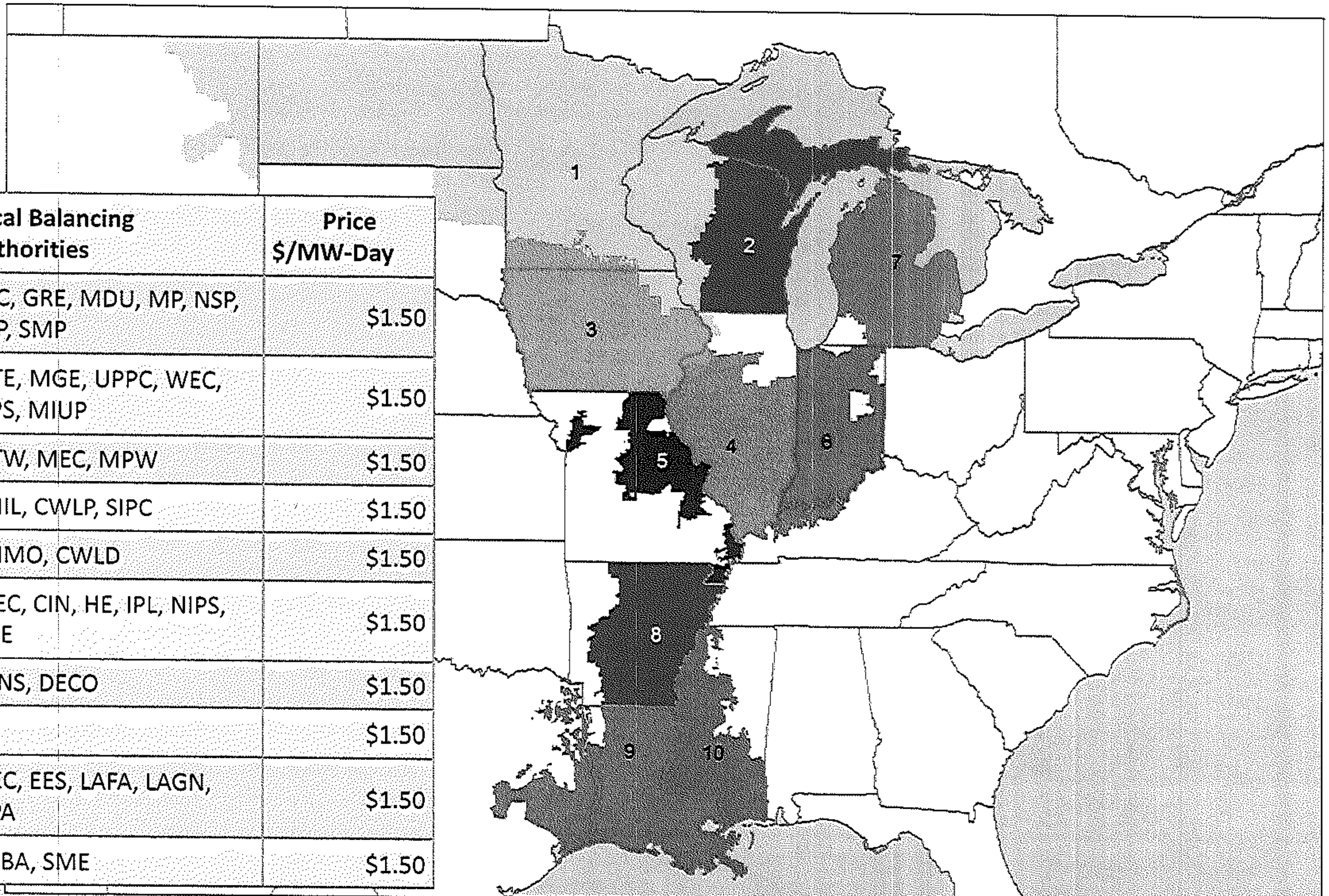
- Tariff revisions approved in FERC Docket No. ER17-806-000 modified the application of the Physical Withholding Threshold to include Market Participants and their Affiliates

- Tariff revisions approved in FERC Docket No. ER16-833-004 established default technology specific avoidable costs, in lieu of providing facility specific operating cost information, to request facility specific Reference Levels from the IMM

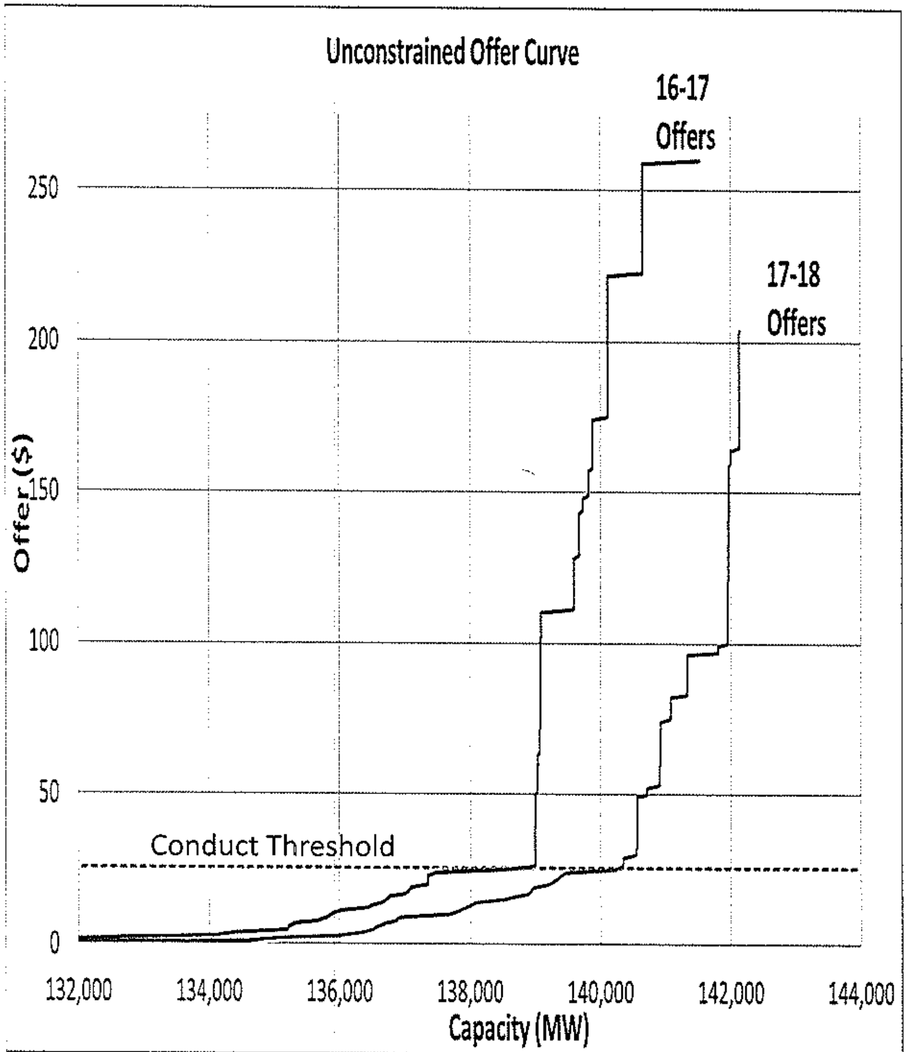
- Sub-Regional Export Constraint in the South to Midwest direction increased to a 1500 MW limit from 876 MW and increased to a 3000 MW limit from 2794 MW in the Midwest to South direction

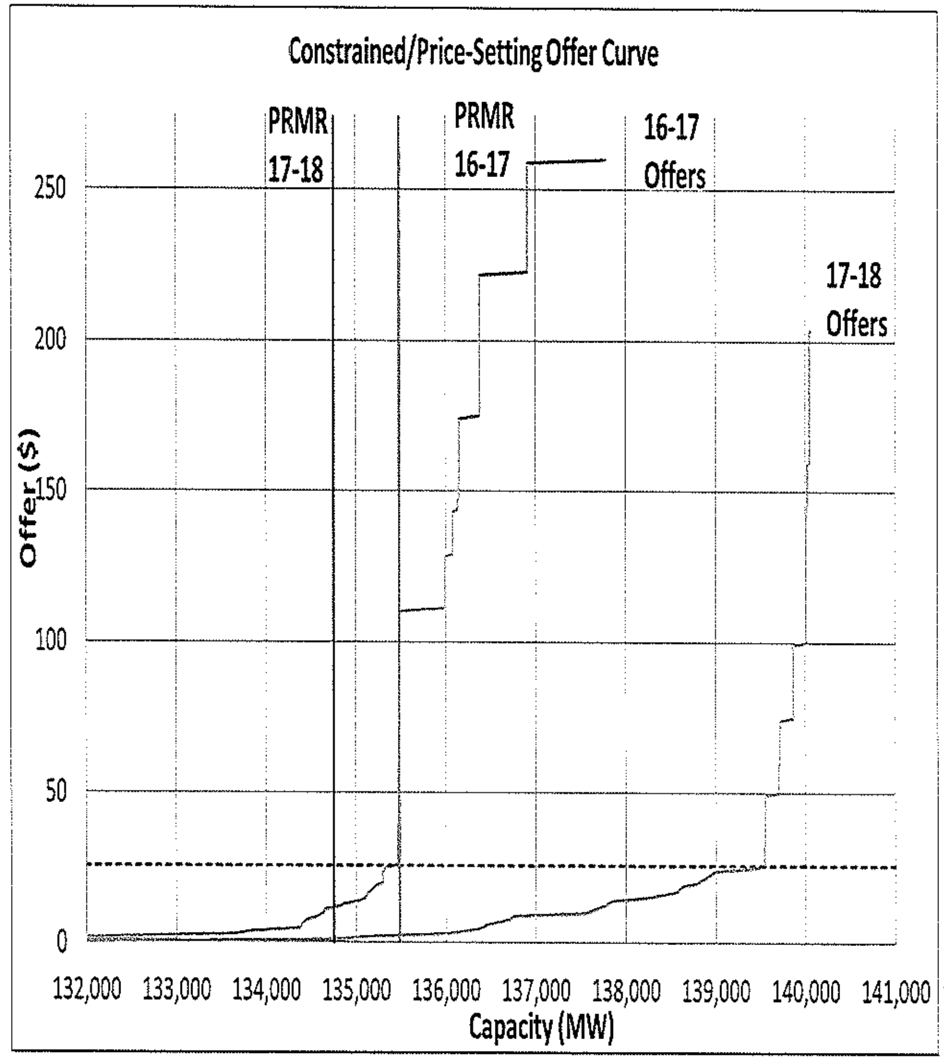
2017/2018 Auction Clearing Price Overview

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$1.50
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$1.50
3	ALTW, MEC, MPW	$1.50
4	AMIL, CWLP, SIPC	$1.50
5	AMMO, CWLD	$1.50
6	BREC, CIN, HE, IPL, NIPS, SIGE	$1.50
7	CONS, DECO	$1.50
8	EAI	$1.50
9	CLEC, EES, LAFA, LAGN, LEPA	$1.50
10	EMBA, SME	$1.50



MISO Offer Curve, 2016/2017 vs. 2017/2018





Capacity constrained by export limits from Zone 1 and MISO South

MISO

Auction Clearing Prices Since 2014-15 PRA

$/MW-day

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2014-2015 ACP*	$3.29	$16.75	$16.75	$16.75	$16.75	$16.75	$16.75	$16.44	$16.44	N/A
2015-2016 ACP*	$3.48	$3.48	$3.48	$150.00	$3.48	$3.48	$3.48	$3.29	$3.29	N/A
2016-2017 ACP*	$19.72	$72.00	$72.00	$72.00	$72.00	$72.00	$72.00	$2.99	$2.99	$2.99
2017-2018 ACP*	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**	**$1.50**
Conduct Threshold	*$25.83*	*$26.09*	*$25.53*	*$25.94*	*$26.45*	*$25.85*	*$26.00*	*$24.79*	*$25.14*	*$24.61*
Cost of New Entry	*$258.32*	*$260.90*	*$255.31*	*$259.42*	*$264.52*	*$258.49*	*$260.00*	*$247.94*	*$251.42*	*$246.13*

- Current Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Current Conduct Threshold is $0 for a generator with a facility specific Reference Level

* Auction Clearing Price

2017/2018 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,316	13,366	9,781	9,894	8,598	18,422	22,295	8,329	20,850	4,902	134,753
Total Offer Submitted (Including FRAP)	19,635	15,149	11,009	10,618	7,950	18,718	22,031	10,914	20,392	5,732	142,146
FRAP	14,361	11,559	4,197	712	0	4,155	12,374	470	182	1,454	49,463
Self Scheduled	4,004	2,113	5,575	7,723	7,948	13,009	9,462	9,660	16,505	3,556	79,554
ZRC Offer Cleared	4,568	2,207	6,088	8,412	7,950	14,510	9,583	9,669	18,470	3,833	85,290
Total Committed (Offer Cleared + FRAP)	18,929	13,766	10,285	9,124	7,950	18,665	21,956	10,139	18,652	5,287	134,753
LCR	15,975	11,980	7,968	5,839	5,885	13,005	21,109	6,766	17,295	4,831	N/A
CIL	3,531	2,227	2,408	5,815	4,096	6,248	3,320	3,275	3,371	1,910	N/A
Import	0	0	0	771	648	0	338	0	2,198	0	3,955
CEL	686	2,290	1,772	11,756	2,379	3,191	2,519	2,493	2,373	1,747	N/A
Export	613	400	503	0	0	243	0	1,810	0	385	3,955
ACP ($/MW-Day)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	N/A

Additional Details Regarding Supply

Planning Resource Type	2017-2018 Offered	2016-2017 Offered	2017-2018 Cleared	2016-2017 Cleared
Generation	127,637	127,329	121,807	122,379
Behind the Meter Generation	3,678	3,487	3,456	3,462
Demand Resources	6,704	6,322	6,014	5,819
External Resources	4,029	4,385	3,378	3,823
Energy Efficiency	98	0	98	0
Total	142,146	141,523	134,753	135,483

- Demand Resource quantities include Aggregator of Retail Customers (ARCs) that registered for the 2017-18 PRA
- Registered Energy Efficiency Resources for the 2017-18 PRA for the first time since the 2013-14 PRA

Next Steps

- Detailed results review at May 10 Resource Adequacy Subcommittee (RASC)
- Posting of PRA offer data 30 days after PRA conclusion – May 12

Acronyms

- ACP - Auction Clearing Price ($/MW-Day)
- ARC - Aggregator of Retail Customers
- BTMG – Behind the Meter Generator
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- CONE – Cost of New Entry
- FRAP - Fixed Resource Adequacy Plan (MW)
- FSRL – Facility Specific Reference Level ($/MW-Day)
- LCR - Local Clearing Requirement (MW)
- LMR – Load Modifying Resource
- LRZ - Local Resource Zone
- PRA - Planning Resource Auction
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- ZRC – Zonal Resource Credit

References

- Sub-Regional Export and Import Constraints discussed at the Resource Adequacy Subcommittee (RASC)
  - November 2, 2016
- Market Monitoring and Mitigation in the Planning Resource Auction
  - February 8, 2017

MISO

2018/2019 Planning Resource Auction Results

April 13, 2018

Executive Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 135,179 MW
  - Zone 1 cleared at $1.00/MW-day
  - Remainder of footprint cleared at $10.00/MW-day
  - Marginal resources located in multiple Zones
  - Increased demand and lower supply largely responsible for higher Auction Clearing Prices relative to last year
  - ZDB rate of $0.04 will be credited to load in Zones 2 through 10

- Regional generation supply is consistent with the 2017 OMS-MISO Survey

- No mitigation for physical or economic withholding by the IMM

Auction Inputs and Considerations

- MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region subject to the following:
  - MISO-wide reserve margin requirements
  - Zonal capacity requirements (Local Clearing Requirement)
  - Zonal transmission limitations (Capacity Import/Export Limits)
  - Sub-Regional contractual limitations such as between MISO's South and Central/North Regions

- The MISO-wide reserve margin requirement is shared among the Zones, and Zones may import capacity to meet this requirement

- Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:
  - Submit a Fixed Resource Adequacy Plan
  - Utilize bilateral contracts with another resource owner
  - Participate in the Planning Resource Auction

- The Independent Market Monitor reviews the auction results for physical and economic withholding

Auction Output and Settlements

- Key outputs from the Auction
  - A commitment of capacity to the MISO region, including performance obligations and
  - The capacity price (Auction Clearing Price) for each Zone

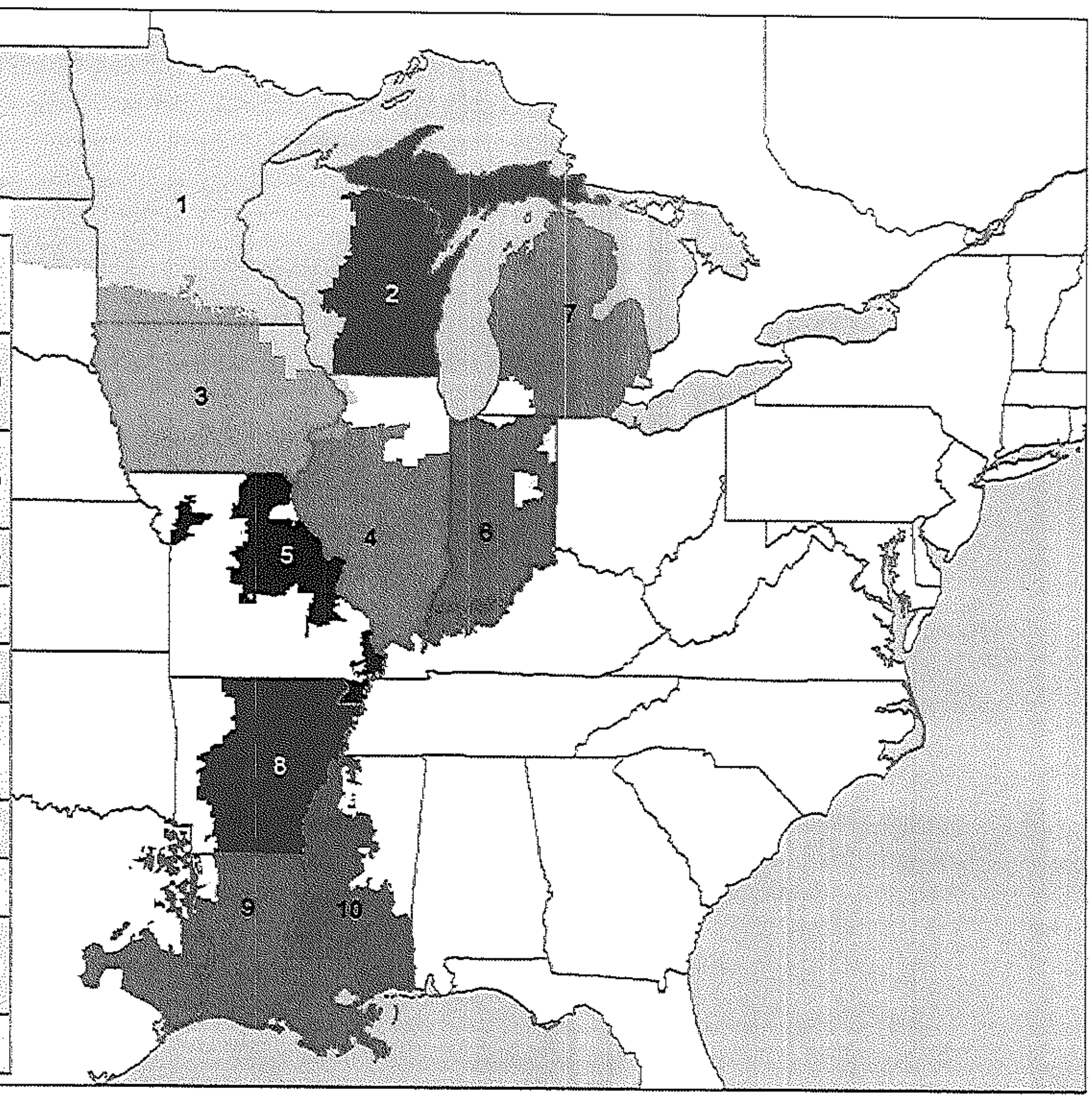
- This price drives the settlements process
  - Load pays the Auction Clearing Price for the Zone in which it is physically located
  - Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located
    - External Resources are paid the price of the Zone where their firm transmission service crosses into MISO

Approved Tariff filings since the 2017/2018 PRA

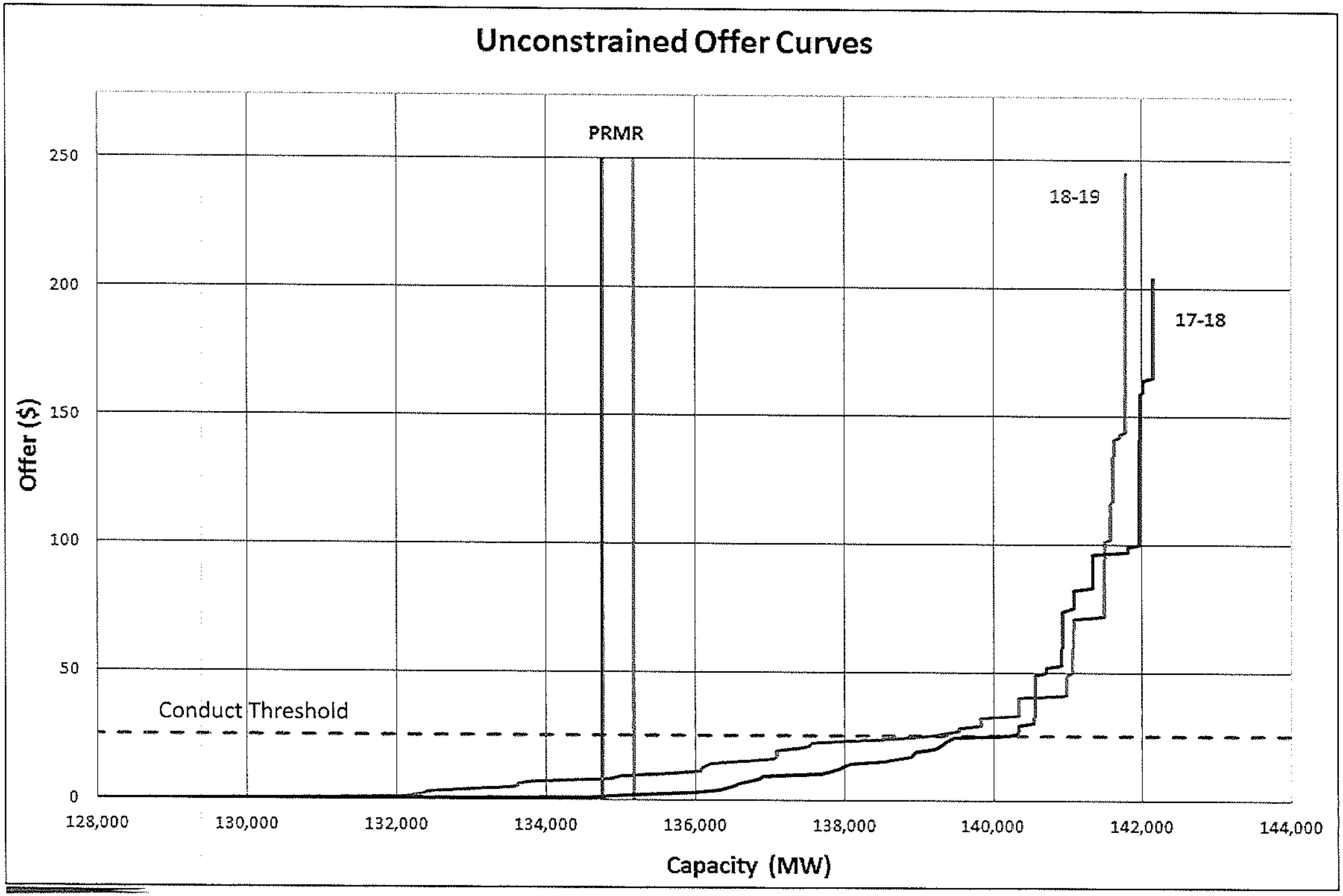
- Tariff revisions approved in FERC Docket ER17-892-000 and -001 documenting the calculation of Sub-Regional Import and Export Constraints and the Independent Market Monitor's calculation of going-forward costs for Reference Levels.
- Tariff revisions approved in FERC Docket ER17-2112 to authorize the extension or reopening of the Planning Resource Auction ("PRA") offer window when necessitated by unanticipated events.
- Tariff revisions approved in FERC Docket ER18-75-000 to allow Market Participants greater flexibility in the qualification of certain resource types for the Planning Resource Auction, allowing for additional components of Installed Capacity to be deferred in addition to the Generation Verification Test Capacity (GVTC).
- Re-filed Tariff provisions (no changes) regarding Planning Resource Auction re-approved in FERC Docket ER18-462-000.

2018/2019 Auction Clearing Price Overview

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$1.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$10.00
3	ALTW, MEC, MPW	$10.00
4	AMIL, CWLP, SIPC	$10.00
5	AMMO, CWLD	$10.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$10.00
7	CONS, DECO	$10.00
8	EAI	$10.00
9	CLEC, EES, LAFA, LAGN, LEPA	$10.00
10	EMBA, SME	$10.00



MISO Offer Curve, 2017/2018 vs. 2018/2019



MISO

Ex. AA-D-16

Auction Clearing Prices Since 2014-15 PRA

$/MW-day

<table>
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<tr><td>2014-2015 ACP*</td><td>$3.29</td><td colspan="6">$16.75</td><td colspan="2">$16.44</td><td>N/A</td></tr>
<tr><td>2015-2016 ACP*</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td></tr>
<tr><td>2016-2017 ACP*</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td></tr>
<tr><td>2017-2018 ACP*</td><td colspan="10">$1.50</td></tr>
<tr><td>2018-2019 ACP*</td><td>$1.00</td><td colspan="9">$10.00</td></tr>
<tr><td>Conduct Threshold</td><td>$24.76</td><td>$24.25</td><td>$24.35</td><td>$24.62</td><td>$25.07</td><td>$24.45</td><td>$24.86</td><td>$23.63</td><td>$22.81</td><td>$23.63</td></tr>
<tr><td>Cost of New Entry</td><td>$247.59</td><td>$242.47</td><td>$243.48</td><td>$246.22</td><td>$250.66</td><td>$244.52</td><td>$248.60</td><td>$236.30</td><td>$228.11</td><td>$236.30</td></tr>
</table>

- Conduct Threshold is 10% of Cost of New Entry (CONE) for each Zone
- Conduct Threshold is $0 for a generator with a facility specific Reference Level

MISO

* Auction Clearing Price

Additional Details Regarding Supply

Planning Resource Type	2018-2019 Offered	2017-2018 Offered	2018-2019 Cleared	2017-2018 Cleared
Generation	126,159	127,637	120,855	121,807
External Resources	3,903	4,029	3,089	3,378
Behind the Meter Generation	4,176	3,678	4,098	3,456
Demand Resources	7,370	6,704	6,964	6,014
Energy Efficiency	173	98	173	98
Total	141,781	142,146	135,179	134,753

- Demand Resource quantities include Aggregators of Retail Customers (ARCs) that registered for the 2018-19 PRA

MISO

* Values displayed in MW UCAP

2018/2019 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,414	13,463	9,805	10,060	8,549	18,741	22,121	8,088	20,976	4,963	135,179
Total Offer Submitted (Including FRAP)	19,560	13,954	10,884	11,002	7,944	19,221	22,036	10,939	21,196	5,046	141,781
FRAP	14,431	11,196	4,170	1,136	0	1,803	12,255	440	172	1,428	47,030
Self Scheduled (SS)	4,046	1,930	5,979	6,636	7,934	16,105	9,193	9,706	16,509	2,858	80,896
Non-SS Offer Cleared	453	215	308	1,155	10	1,179	352	241	2,782	558	7,253
Total Committed (Offer Cleared + FRAP)	18,930	13,342	10,456	8,927	7,944	19,087	21,801	10,387	19,463	4,844	135,179
LCR	15,832	12,373	7,374	4,960	5,693	12,090	20,628	4,744	19,319	4,463	N/A
CIL	4,415	2,595	3,369	6,411	4,332	7,941	3,785	4,834	3,622	2,688	N/A
Import	0	121	0	1,133	606	0	320	0	1,513	120	3,812
CEL	516	2,017	5,430	4,280	2,122	3,249	2,578	2,424	2,149	1,824	N/A
Export	516	0	651	0	0	346	0	2,299	0	0	3,812
ACP ($/MW-Day)	$1.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	N/A

* Values displayed in MW UCAP

Next Steps

- Detailed results review at May 9 Resource Adequacy Subcommittee (RASC)
- Posting of PRA offer data 30 days after PRA conclusion – May 18
- Results from previous Planning Resource Auctions can be found on the MISO website at: Planning-> Resource Adequacy -> PRA Document

Acronyms

- ACP - Auction Clearing Price ($/MW-Day)
- ARC - Aggregator of Retail Customers
- BTMG – Behind the Meter Generator
- CEL - Capacity Export Limit (MW)
- CIL - Capacity Import Limit (MW)
- CONE – Cost of New Entry
- FRAP - Fixed Resource Adequacy Plan (MW)
- FSRL – Facility Specific Reference Level ($/MW-Day)
- LCR - Local Clearing Requirement (MW)
- LMR – Load Modifying Resource
- LRZ - Local Resource Zone
- PRM - Planning Reserve Margin (%)
- PRMR - Planning Reserve Margin Requirement (MW)
- SREC – Sub-Regional Export Constraint
- SRIC – Sub-Regional Import Constraint
- ZDB – Zonal Deliverability Benefit
- ZRC – Zonal Resource Credit

Ex. AA-D-17

MISO

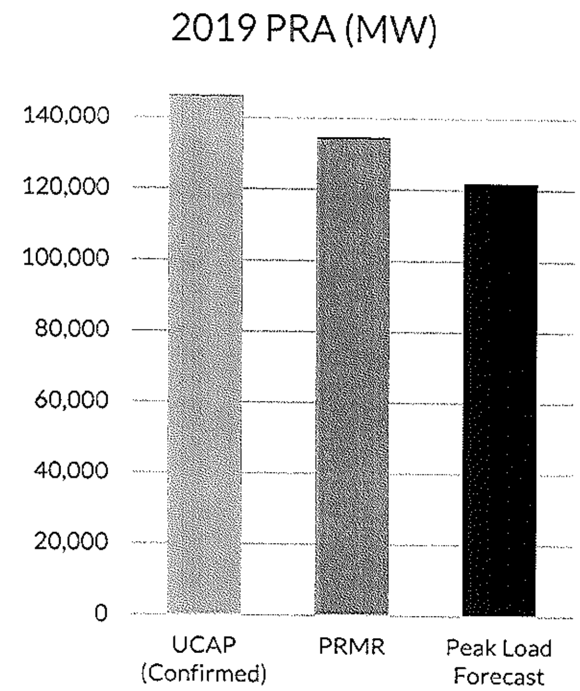
2019/2020 Planning Resource Auction (PRA) Results

April 12, 2019

04/12/2019: MISO Planning Resource Auction (PRA) for Planning Year 2019-2020 Results Posting

Summary

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of nearly 135,000 MW
- Footprint cleared at $2.99/MW-day
- Zone 7 (MI) cleared at $24.30/MW-day
- Regional generation supply consistent with the 2018 OMS-MISO Survey
- Several offers (~1.5MW) were mitigated by the Independent Market Monitor (IMM) for economic withholding, with a $0.01/MW-day impact on Zone 7.



Background

MISO's Resource Adequacy construct combines regional and local criteria to achieve a least-cost solution for the region

Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:

- Submit a Fixed Resource Adequacy Plan (FRAP)
- Utilize bilateral contracts with another resource owner
- Participate in the Planning Resource Auction (PRA)

The Independent Market Monitor (IMM) reviews the auction results for physical and economic withholding

Inputs

- Local Clearing Requirement (LCR) = capacity required from within each zone
- MISO-wide reserve margin requirements, which can be shared among the Zones, and Zones may import capacity to meet this requirement above LCR
- Capacity Import/Export Limits (CIL/CEL) = Zonal transmission limitations
- Sub-Regional contractual limitations such as between MISO's South and Central/North Regions

Outputs

- Commitment of capacity to the MISO region, including performance obligations
- Capacity price (ACP = Auction Clearing Price) for each Zone
- ACP price drives the settlements process
- Load pays the Auction Clearing Price for the Zone in which it is physically located
- Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located

Changes Since 2018 Auction

TREATMENT OF EXTERNAL RESOURCES (ER18-2363):

In Oct. 2018, FERC approved MISO's filing to improve consistency between resources outside of MISO and resources external to a Local Resource Zone but within the footprint.

NEW REQUIREMENTS FOR LOAD MODIFYING RESOURCES (ER19-650):

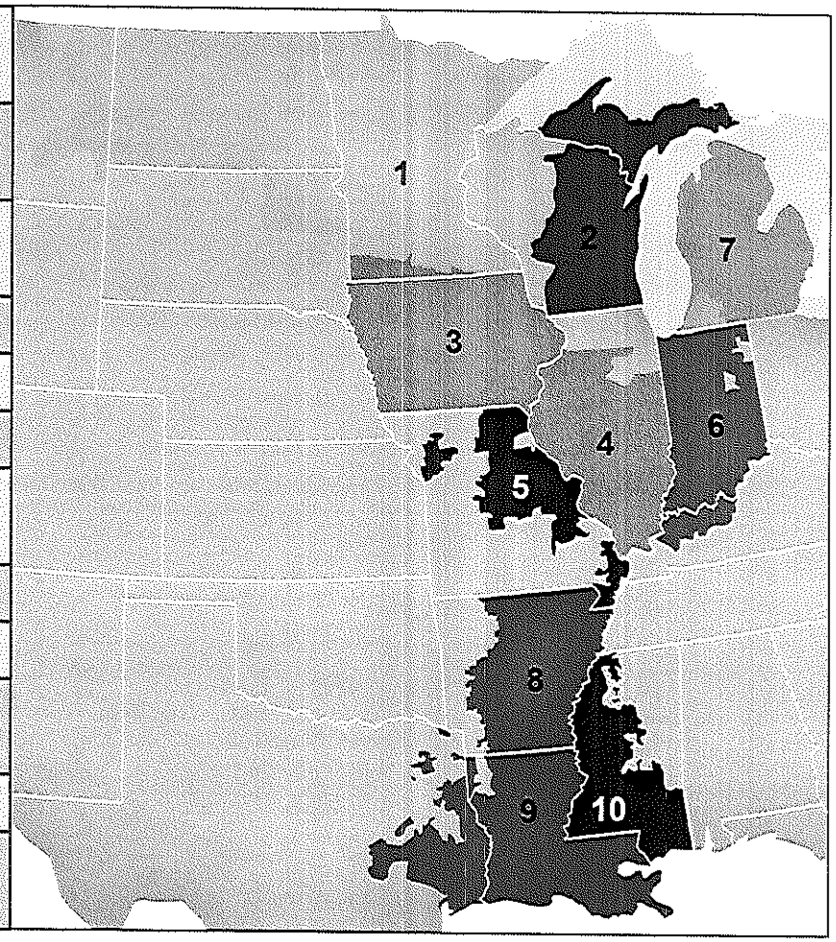
In Feb. 2019, FERC approved part of MISO's Resource Availability and Need initiative related to Load Modifying Resource (LMR) availability. LMRs must now make themselves available for as much of the year as possible and with the shortest-possible notification times.

ONGOING FLEET CHANGE:

The auction results reflect the industry's ongoing shift away from coal-fired generation and increasing reliance on gas-fired resources and renewables, as well as other trends discussed in our MISO Forward report.

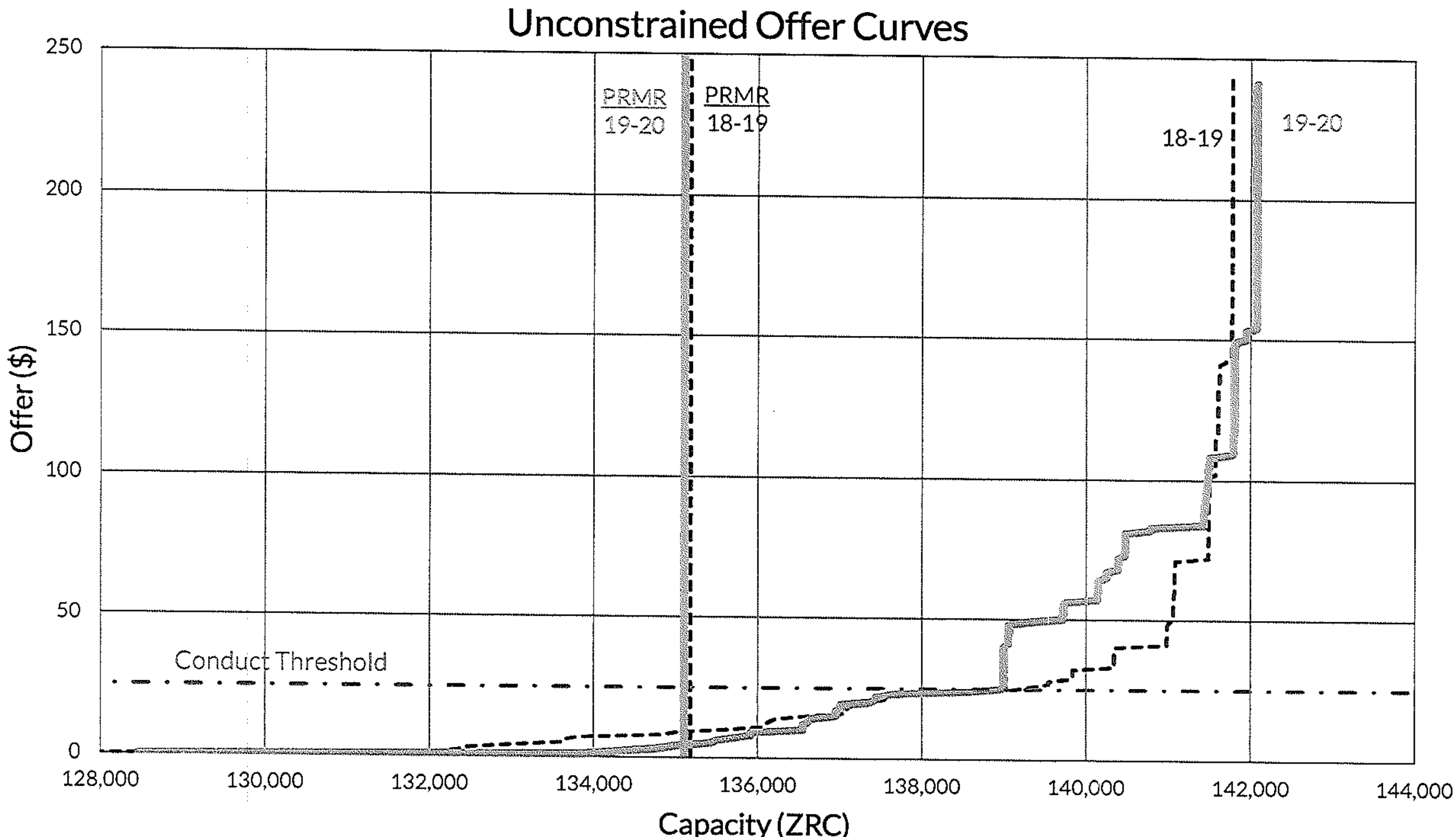
2019/2020 Auction Clearing Price Overview

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$2.99
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$2.99
3	ALTW, MEC, MPW	$2.99
4	AMIL, CWLP, SIPC	$2.99
5	AMMO, CWLD	$2.99
6	BREC, CIN, HE, IPL, NIPS, SIGE	$2.99
7	CONS, DECO	$24.30
8	EAI	$2.99
9	CLEC, EES, LAFA, LAGN, LEPA	$2.99
10	EMBA, SME	$2.99
ERZ	SPP, PJM, OVEC, LGEE, AECI, SPA, TVA	$2.99



ERZ = External Resource Zones

Offer Curve: 2018/19 vs 2019/20



2019/20 Planning Resource Auction Results

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,374.9	13,449.9	9,882.0	9,792.3	8,297.1	18,659.8	21,976.0	7,963.5	21,350.2	4,997.3	N/A	134,743.0
Offer Submitted (Including FRAP)	20,187.3	13,575.1	11,009.4	11,428.8	7,959.7	17,946.9	22,063.2	10,611.8	21,162.4	4,593.0	1,545.0	142,082.6
FRAP	14,318.7	11,278.9	4,124.4	832.1	0.0	1,587.0	12,096.9	489.4	171.9	1,380.3	134.6	46,414.2
Self Scheduled (SS)	3,938.1	2,258.0	6,187.6	6,249.7	7,844.1	13,945.1	9,682.7	9,276.5	18,750.5	2,644.1	1,270.5	82,046.9
Non-SS Offer Cleared	404.4	0.0	79.1	1,523.7	0.0	2,069.4	32.0	443.9	1,232.7	368.9	127.8	6,281.9
Committed (Offer Cleared + FRAP)	18,661.2	13,536.9	10,391.1	8,605.5	7,844.1	17,601.5	21,811.6	10,209.8	20,155.1	4,393.3	1,532.9	134,743.0
LCR	16,588.7	13,017.5	7,960.2	6,222.1	4,860.1	13,226.1	21,811.6	6,116.3	19,525.2	3,048.8	-	N/A
CIL	3,754	1,714	2,896	6,771	5,013	7,067	3,211	4,250	3,631	3,792	-	N/A
ZIA	3,753	1,713	2,987	5,312	5,013	6,924	3,211	4,249	3,631	3,792	-	N/A
Import	0.0	0.0	0.0	1,186.8	453.0	1,058.3	164.4	0.0	1,195.1	604.0	-	4,661.6
CEL	3,373.2	978.7	4,589.7	3,770.2	2,122.0	1,434.5	1,358.0	5,263.1	2,223.6	1,721.0	-	N/A
Export	286.3	87	509.1	0	0	0	0	2,246.3	0	0	1532.9	4,661.6
ACP ($/MW-Day)	2.99	2.99	2.99	2.99	2.99	2.99	24.30	2.99	2.99	2.99	2.99	N/A

Values displayed in MW UCAP

Historical Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2014-2015	$3.29			$16.75				$16.44		N/A	N/A
2015-2016		$3.48		$150.00		$3.48			$3.29	N/A	N/A
2016-2017	$19.72			$72.00					$2.99		N/A
2017-2018					$1.50						N/A
2018-2019	$1.00					$10.00					N/A
2019-2020			**$2.99**				**$24.30**		**$2.99**		

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Conduct Threshold	*24.24*	*23.88*	*23.95*	*24.22*	*24.65*	*24.05*	*24.34*	*23.23*	*22.37*	*23.12*	*24.65*
Cost of New Entry	*242.36*	*238.82*	*239.51*	*242.16*	*246.47*	*240.49*	*243.37*	*232.27*	*223.67*	*231.15*	*246.47*

- Auction Clearing Prices & are displayed as $/MW-day
- Conduct Threshold is 10% of Cost of New Entry (CONE)
- Conduct Threshold is $0 for a generator with a Facility Specific Reference Level

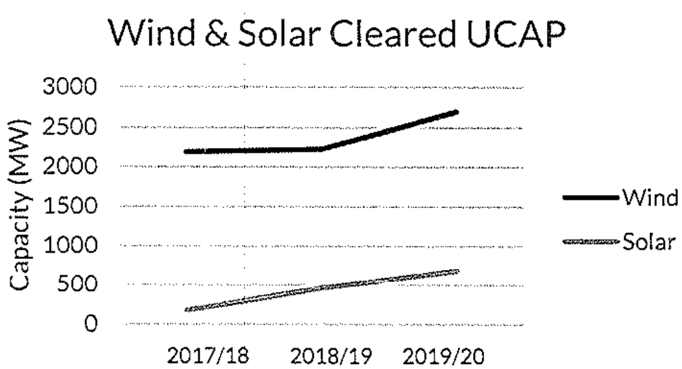
Supply Offered & Cleared

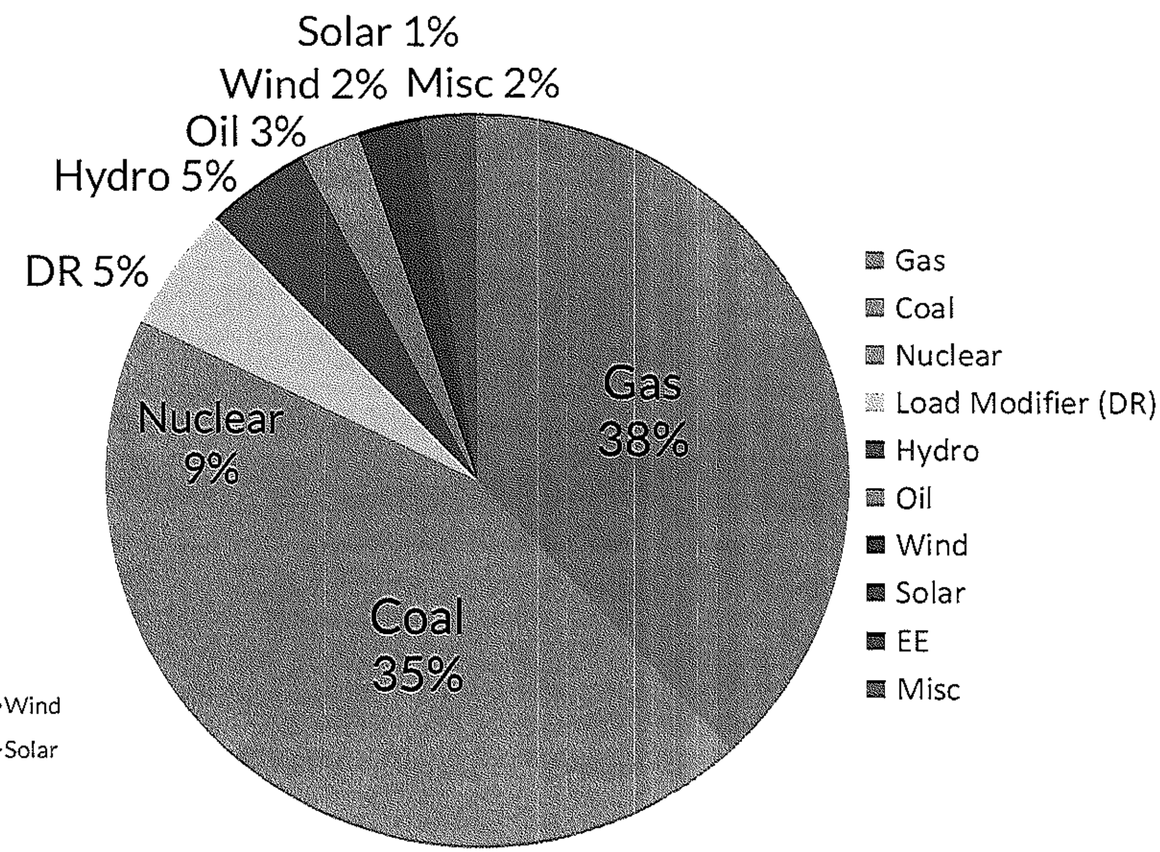
Planning Resource Type	2018-2019 Offered	2019-2020 Offered	2018-2019 Cleared	2019-2020 Cleared
Generation	126,159	125,290	120,855	119,779
External Resources	3,903	4,402	3,089	3,183
Behind the Meter Generation	4,176	4,202	4,098	4,097
Demand Resources	7,370	7,876	6,964	7,372
Energy Efficiency	173	312	173	312
Total	141,781	142,082	135,179	134,743

2019 Cleared Fuel Type

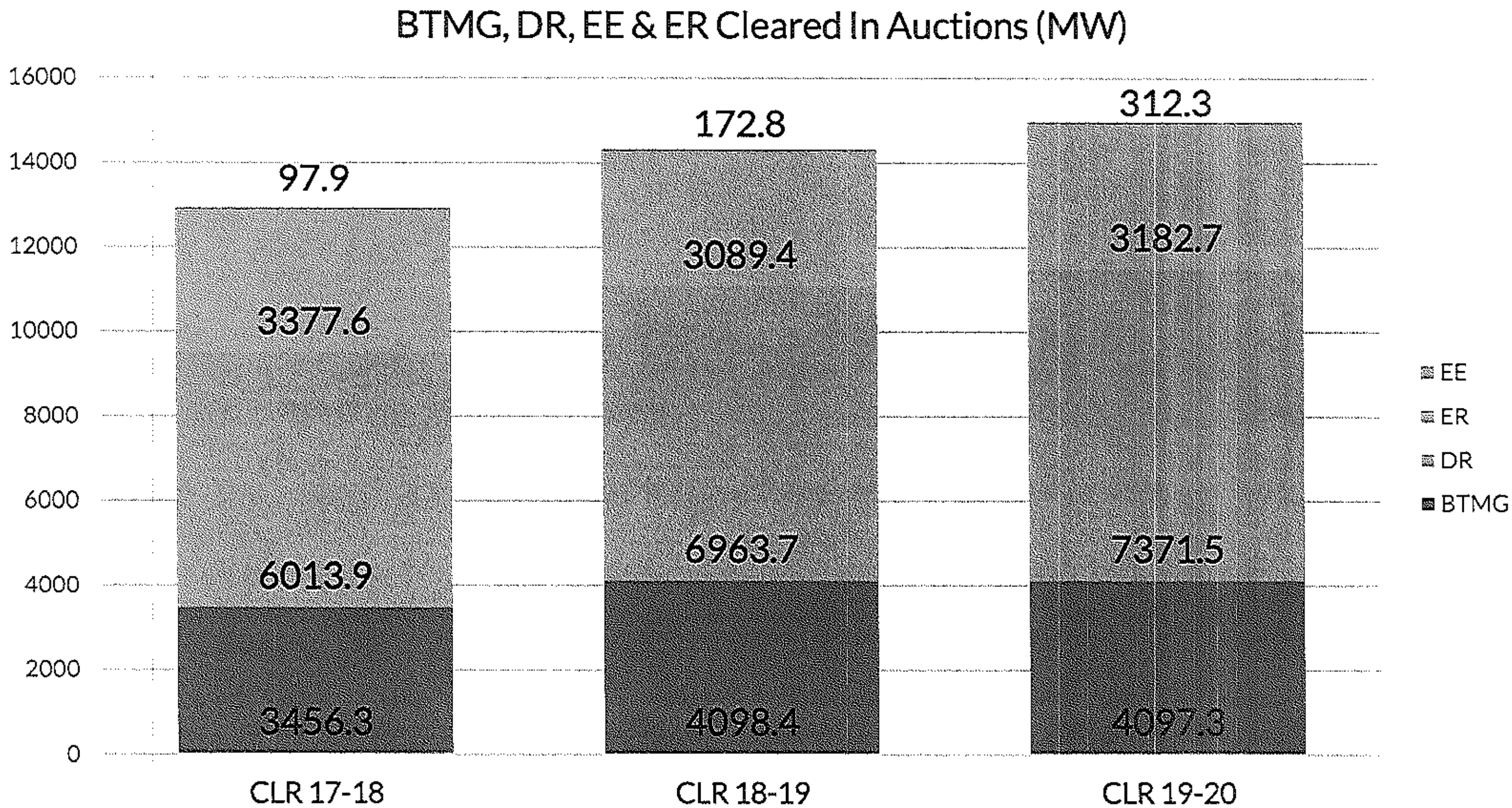
While solar still comprises a relatively small percentage of the region's total capacity, 680 MW of solar cleared this year's auction—an increase of 47% over last year's mark of 461 MW.

Similarly, 2,698 MW of wind cleared this year, an increase of 21%, or 469 MW, compared to last year.





Non Traditional Resources



Next Steps

- APR 15 – Conference call presentation of PRA results
- MAY 8 – Detailed results review at RASC
- MAY 13 – Posting of PRA offer data
- MAY 31 – LSE submit ICAP Deferral info
- JUN 1 – New Planning Year starts

Appendix

Acronyms

ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
DR: Demand Resource
EE: Energy Efficiency
ER: External Resource
ERZ: External Resource Zones
FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor
LCR: Local Clearing Requirement
LMR: Load Modifying Resource
LRZ: Local Resource Zone
LSE: Load Serving Entity
PRA: Planning Resource Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
SS: Self Schedule
SFT: Simultaneous Feasibility Test
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

MISO

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