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 5,364 MW.

Labadie Energy Center

Labadie plant 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 2,374 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:

- The state of Missouri presented Labadie Energy Center with the Resource Steward Award in 1983 to honor the company's efforts toward "preserving and wisely using Missouri's precious resource" by removing PCBs from our environment. Between 1981 and 1997, Labadie converted more than 4.5 million gallons of PCB-contaminated oil into an estimated 56,000 MWhs of electricity.
- In 1998, Labadie was one of three Ameren Missouri plants to earn the Missouri Governor's Pollution Prevention Award for successfully reducing nitrogen oxide (NO_X) emissions- 50% more than required by Missouri regulations.
- In 2000, Labadie was recognized by the Environmental Protection Agency as the nation's lowest emitter of NO_X.
- In 2011, Labadie was recognized as the Best Large Plant Performer by the Electric Utility Cost Group (EUCG).
- In 2014, Navigant awarded Labadie a plant operational excellence award as the top performing large unit coal-fired energy center in the U.S.

From 2000 to 2009, Labadie set generation records in six out of ten years. Labadie Unit 2 Low Pressure (LP) turbine retrofits were among the existing plant upgrades included in the Company's 2008 IRP. In Spring 2012, the high pressure (HP) and intermediate pressure (IP) turbines were cleaned, some turbine seals and packing were replaced, and new LP turbines were installed at Labadie Unit 2. For the same turbine inlet conditions, these new LP turbines are designed to provide an additional 12 MW of net generation.

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 1,182 MW. The first unit started operation in 1976 and the second unit in 1977.

In Spring 2011, the HP and IP turbines were cleaned, some turbine seals and packing were replaced, and new LP turbines were installed at Rush Island Unit 1. The cleaning and seal replacement improved the efficiency of the HP and IP turbines. For the same turbine inlet conditions, these new LP turbines are designed to provide an additional 12 MW of net generation.

Meramec Energy Center

Meramec Energy Center is located in South St. Louis County on the Mississippi River on 420 acres. The plant began operation in 1953. Net summer capability of the four coal-fired units at the site is 834 MW. It is the oldest coal plant in Ameren Missouri's fleet. An updated detailed condition assessment study of the Meramec coal-fired units was completed by Burns and McDonnell in May 2014.

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 974 MW.

Sioux Energy Center has accomplished many industry firsts:

- Pioneered slag-removal techniques now used nationwide.
- One of the first to install cyclone furnaces that can burn multiple fuels.
- One of the first to receive coal on the unit train concept.

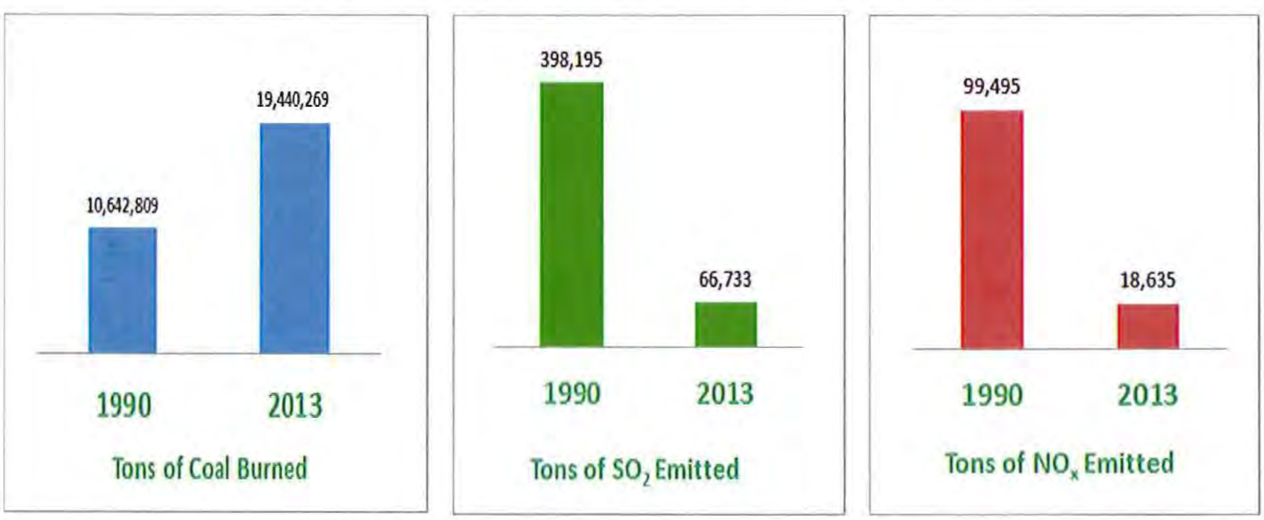
- Became the first generating plant in Missouri to burn chipped rubber tires to augment coal as an alternate fuel source. Sioux Energy Center has burned more than 19 million discarded tires, which would otherwise end up in a landfill, without adversely affecting power plant emissions from 1992 to 2006.

Ameren Missouri has installed wet flue gas desulfurization (FGD) equipment (i.e., scrubbers) at Sioux to comply with the federal Clean Air Interstate Rule (CAIR). CAIR required a major reduction in sulfur dioxide (SO_2) and NO_X emissions on a regional scale by 2015 to help areas in the eastern U.S. achieve improved air quality. The Sioux scrubbers will now help Ameren Missouri to comply with the Cross-State Air Pollution Rule (CSAPR), which will replace CAIR when implemented. When the scrubbers were installed, the tire handling facilities were removed and chipped tires can no longer be burned. The Sioux scrubbers are capable of removing up to 99% of the SO_2 from the boiler flue gas and started operating in October and November 2010.

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 customer's 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 SO_2 and NO_x 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 Fall 2011, two CTG plants were retired: Venice 1 (Net Capability: 25 MW) and Viaduct (Net Capability: 25 MW).

Table 4.1 lists the Ameren Missouri combustion turbines and their 2014 summer net generating capabilities. **NP**[redacted]

[redacted]**

Table 4.1 CTG Capability

Plant	Fuel	Net MW
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	99
Peno Creek	Gas/Oil	188
Venice	Gas/Oil	487
Fairgrounds	Oil	54
Howard Bend	Oil	39
Mexico	Oil	54
Moberly	Oil	54
Moreau	Oil	54
Total		2,896

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. It is the second largest power generator on the Ameren Missouri system with a net capability of 1,190 MW, after Labadie. More than 900 Ameren Missouri employees and contractors work at the plant.

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

4.1.4 Existing Renewable and Storage Resources

Currently, Ameren owns and operates 381 MW of hydroelectric resources and 440 MW of pumped storage with an additional purchase power agreement for 102 MW of wind generation. In December 2010, Ameren Missouri completed the installation of approximately 100 kW of solar panels at its St. Louis General Office Building (GOB) using monocrystalline, polycrystalline and thin-film technologies. In June 2012, Ameren Missouri began operation of 9 MW (net) of landfill gas generation at the Maryland Heights Renewable Energy Center (MHREC) in west St. Louis County.

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 141 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 millions of dollars for the modernization and repair of the plant and dam.

Ameren Missouri also owns some 12,000 acres of flowage land and land covered by water. The company controls or has flowage rights on a total of 55,000 acres of land above the dam, including many islands, wetlands, and timberlands. The lake is a haven for boating and fishing and hosts several nationally recognized bass tournaments.

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 Keokuk Energy Center was certified as a qualified renewable energy resource by the MoDNR in September 2011.

Keokuk Energy Center completed two unit upgrades in July 2012. As a result, the ratings on Keokuk Units 2 and 4 increased 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, which take thousands of years to replace, 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.

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 for short periods. Water stored in an upper reservoir is released to flow through turbines and into a lower reservoir during high energy demands. Then, overnight, when the demand for electricity is low, the water is pumped back into the upper reservoir, where it is stored until needed. As water passes through the powerhouse, water spins the turbines, which drive generators to produce electricity. The Taum Sauk facility has a pump back efficiency of 71.4%.

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. Since Phase II does not currently meet the MISO deliverability requirements of a Capacity Resource, Ameren Missouri would be required to pay for a study to determine deliverability and possibly need to purchase firm transmission to utilize this capacity to meet the planning reserve margin requirements in Missouri. Because MISO only provides for 14% of the nameplate rating of a wind generator to be counted as capacity when it is deliverable and because capacity prices in MISO remain relatively low, incurring the expense to establish deliverability has not been considered economically viable to this point.

Ameren Missouri Headquarters Solar Installation

In December 2010, Ameren Missouri completed the installation of approximately 100 kW of various photovolatic solar technologies using monocrystalline, polycrystalline and thin-film technologies at its headquarters office building located in St. Louis. The Ameren Missouri GOB solar installation was certified as a qualified renewable generation facility by the MoDNR in September 2011. The goal of Ameren Missouri's Solar Energy Project is to provide a state-of-the-art testing ground to compare various solar technologies. This allows our customers to determine which photovoltaic components will best suit their home or business needs. In addition, Ameren Missouri established an Energy Learning Center at our St. Louis Headquarters where visitors are able to see our rooftop solar energy system and learn more about renewable energy at Ameren.

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 9 MW (net). This facility burns methane gas produced by the IESI Landfill in Maryland Heights, MO, in three Solar 4.9 MW 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[4]

The levelized cost of energy was calculated for Ameren Missouri's existing resources. It is important to note that the levelized cost of energy figures do not fully capture all of the relative strengths and challenges of each resource type. Table 4.2 shows the component analysis for the levelized cost of energy for each energy center. The average levelized cost of energy for Ameren Missouri's coal energy centers is approximately $58/MWh. The average levelized cost of energy for Ameren Missouri's entire generating fleet is approximately $82/MWh.

Table 4.2 Levelized Cost of Energy Component Analysis for Existing Resources

Resource	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	
Existing Resources											
Labadie	0.52	0.45	3.06	--	--	0.68	0.23	0.37	0.00	0.01	**5.33**
Rush Island	0.44	0.60	3.19	--	--	0.20	0.05	0.41	0.00	0.00	**4.89**
Meramec	0.26	1.71	2.82	--	--	2.10	0.17	0.09	0.00	0.00	**7.16**
Sioux	1.06	0.85	2.88	--	--	0.74	0.09	0.25	0.00	0.00	**5.88**
Audrian	0.00	0.46	7.00	--	--	--	0.00	0.15	0.00	0.00	**7.61**
Goose Creek	0.01	0.57	8.09	--	--	--	0.00	0.18	0.00	0.00	**8.84**
Kirksville	0.00	0.02	8.61	--	--	--	--	0.00	0.00	0.00	**8.63**
Pinckneyville	0.00	1.59	8.01	--	--	--	--	0.17	0.00	0.00	**9.78**
Raccoon Creek	0.00	0.78	8.68	--	--	--	--	0.19	0.00	0.00	**9.64**
Kinmundy	0.00	1.61	8.01	--	--	--	--	0.17	0.00	0.00	**9.80**
Meramec CTG	0.02	0.12	4.70	--	--	--	--	0.00	0.00	0.00	**4.85**
Peno Creek	0.01	3.49	8.01	--	--	--	--	0.17	0.00	0.00	**11.69**
Venice	0.00	0.97	6.46	--	--	--	--	0.14	0.00	0.00	**7.57**
Fairgrounds	0.80	0.12	8.61	--	--	--	--	0.00	0.00	0.00	**9.52**
Howard Bend	4.84	2.56	6.02	--	--	--	--	0.00	0.00	0.00	**13.42**
Mexico	0.00	0.39	8.89	--	--	--	--	0.00	0.00	0.00	**9.28**
Moberly	0.00	0.34	5.90	--	--	--	--	0.00	0.00	0.00	**6.25**
Moreau	0.00	0.17	9.74	--	--	--	--	0.00	0.00	0.00	**9.91**
Callaway	1.82	1.99	1.16	0.07	--	--	--	0.00	0.00	0.00	**5.05**
Keokuk	1.80	0.51	0.00	--	--	--	--	0.00	0.00	0.00	**2.31**
Osage	2.00	1.34	0.00	--	--	--	--	0.00	0.00	0.00	**3.34**
Taum Sauk	0.75	1.20	0.00	--	7.74	--	--	0.00	0.00	0.00	**9.69**
Maryland Heights CTG	0.04	10.41	7.39	--	--	--	0.00	0.00	0.00	0.00	**17.84**

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

4.1.6 Planned Changes to Existing Non-Coal Resources

During the 20-year planning horizon, Ameren Missouri is considering four Keokuk Energy Center Units for upgrades, adding a new CTG unit at MHREC, adding the largest investor-owned utility solar center in Missouri with approximately 5.7 MW [direct current (DC)] capacity, and the potential retirement of eight CTG units.

Portfolio Upgrades

Keokuk Energy Center is scheduled to complete two unit upgrades in 2016. The net output on Keokuk Units 5 and 6 will increase by 2 MW each with a total capital cost of approximately $23.5 million (for the turbine component upgrades only) budgeted in 2014, 2015, and 2016. In addition, two unit upgrades at Keokuk Energy Center are scheduled to be complete in 2018. The net output Keokuk Units 14 and 15 will increase by 2 MW each with a total capital cost of approximately $25 million (for the turbine component upgrades only) budgeted in 2016, 2017, and 2018.

Ameren Missouri is considering adding a fourth CTG unit at MHREC that will be in service in 2018. The fourth unit will provide an additional 3-4 MW of summer net capacity with a total capital cost of $16-18 million in 2017-2018 and will provide additional renewable energy needed for meeting the requirements of Missouri's Renewable Energy Standard (RES).

Ameren Missouri intends to install 5.7 MW (DC) of solar photovoltaic generation next to the Ameren Missouri Belleau substation in St. Charles County. The solar center, O'Fallon Renewable Energy Center (OREC), will feature approximately 19,000 solar panels covering approximately 20 acres on land owned by Ameren Missouri. Construction is anticipated to begin in spring 2014. The installation is scheduled to be in service by 2015 with a total capital cost ranging from $10-$20 million in 2014.

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 of its eight older gas and oil fired CTG units (i.e., Kirksville, Howard Bend, 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 38 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).

In 2013, only one engine at Howard Bend successfully operated during testing for MISO operating compliance. The existing stack is also severely deteriorated and must be replaced. In order for both engines at Howard Bend to be operated reliably, approximately $2.4 million of capital and approximately $1.4 million of O&M improvements would be needed to operate the unit in the near-term. In addition, annual expenses of at least $100,000 are anticipated at Howard Bend for items including maintenance, monthly runs, and inspections. An economic analysis was conducted to determine the present value of revenue requirements (PVRR) if the improvements were implemented at Howard Bend. The PVRR, which includes benefits of capacity value, is approximately $2 million net costs to customers, indicating that the improvements are not beneficial. It is likely that Howard Bend will be 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.

The existing stack at Fairgrounds is severely deteriorated and needs to be replaced. There is a strong possibility that Fairgrounds will be retired in 2015 due to costs associated with replacing the stacks, the age of the unit, long-term availability of spare parts, and safety. With respect to the remaining CTGs listed in Table 4.3, as the assumed retirement date for each unit approaches, a detailed condition assessment of each unit will be developed to accurately assess the asset's condition and develop a work scope with estimated costs to make the assets reliable and operational.

Table 4.3 Ameren Missouri Potential CTG Retirements during the Planning Period

Unit	Capacity (MW)	Fuel Type	Commerical Operation Date	Age as of 12/31/2013	Retirement Time Frame
Kirksville	13	Natural Gas	1967	46	12/31/2017
Howard Bend	39	Oil	1973	40	01/31/2015
Fairgrounds	54	Oil	1974	39	06/30/2015
Meramec CTG-1	54	Oil	1974	39	12/31/2017
Meramec CTG-2	45	Natural Gas/Oil	1999 (1)	37	12/31/2020
Mexico	54	Oil	1978	35	12/31/2020
Moberly	54	Oil	1978	35	12/31/2020
Moreau	54	Oil	1978	35	12/31/2020

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

The results of the 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 and availability of spare parts.

4.2 Existing Coal 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 12/31/2013, 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	12/31/2013	(Retirement Date)
Labadie	1970	1971	1972	1973	42	2042
Meramec	1953	1954	1959	1961	57	2022
Rush Island	1976	1977			37	2046
Sioux	1967	1968			46	2033

4.2.1 Reliability Trends

One of the key measures used by Ameren Missouri to measure coal energy center performance is the equivalent availability factor (EAF). The EAF is a measure of how much energy could be produced if the plant is operated at its full capability after taking into account down time for repairs. Down time could be for long term planned outages, short term forced or maintenance outages for minor repairs, or equipment or other limitations that prevent the unit from operating at its rated output. Figures 4.3 to 4.6 present the EAF charts contain a rolling 12 month, a rolling 36 month, and a rolling 72 month trend for each coal energy centers. The rolling 72 month (6 year) measure is the most relevant to resource planning because the planned outages, which occur at long intervals, distort the EAF trends produced by the rolling 12 month or rolling 36 month trends. The EAF calculations were done with the North American Electric Reliability Corporation (NERC) conversion method of Outside Management Control events. Some events may be excluded from the calculations.

Figures 4.3 to 4.6 do not indicate any sustained downward trends in EAF which would indicate a deterioration of energy centers as they age. It is important to note that maintaining levels of reliability is in part dependent on the continued maintenance of and investments in equipment.

Figure 4.3 Labadie Energy Center Equivalent Availability

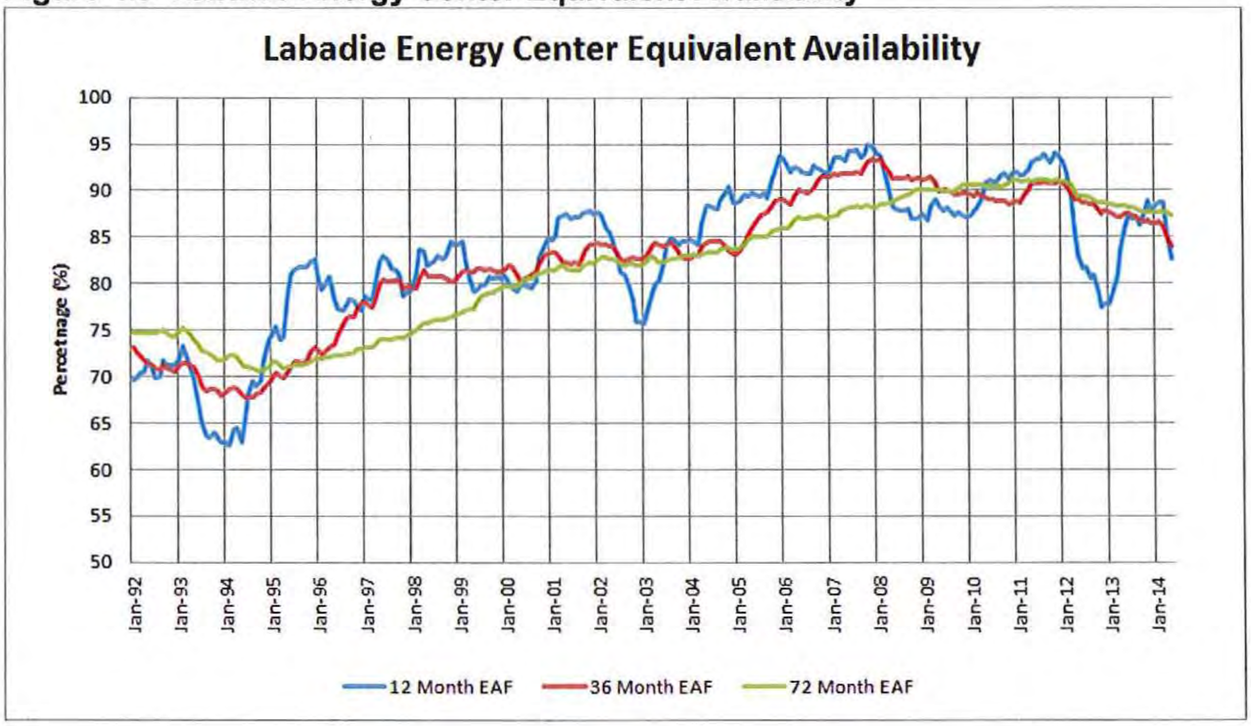


Figure 4.4 Meramec Energy Center Equivalent Availability

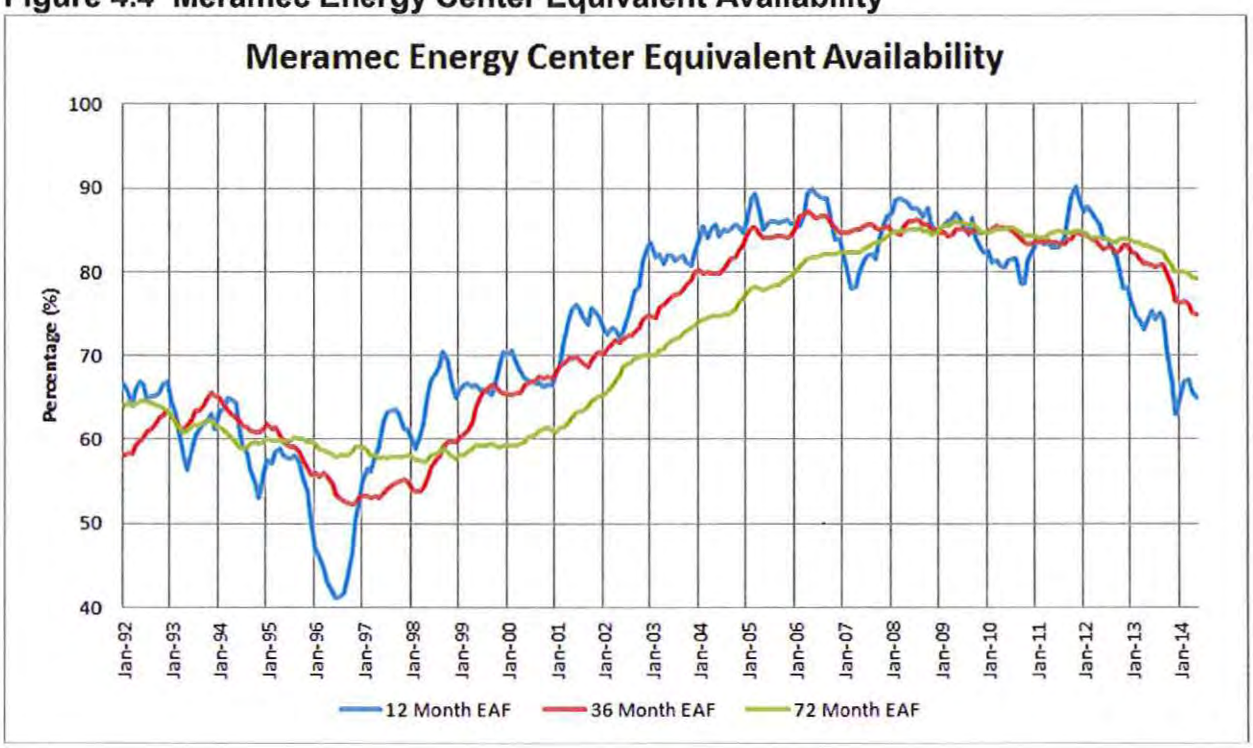


Figure 4.5 Rush Island Energy Center Equivalent Availability

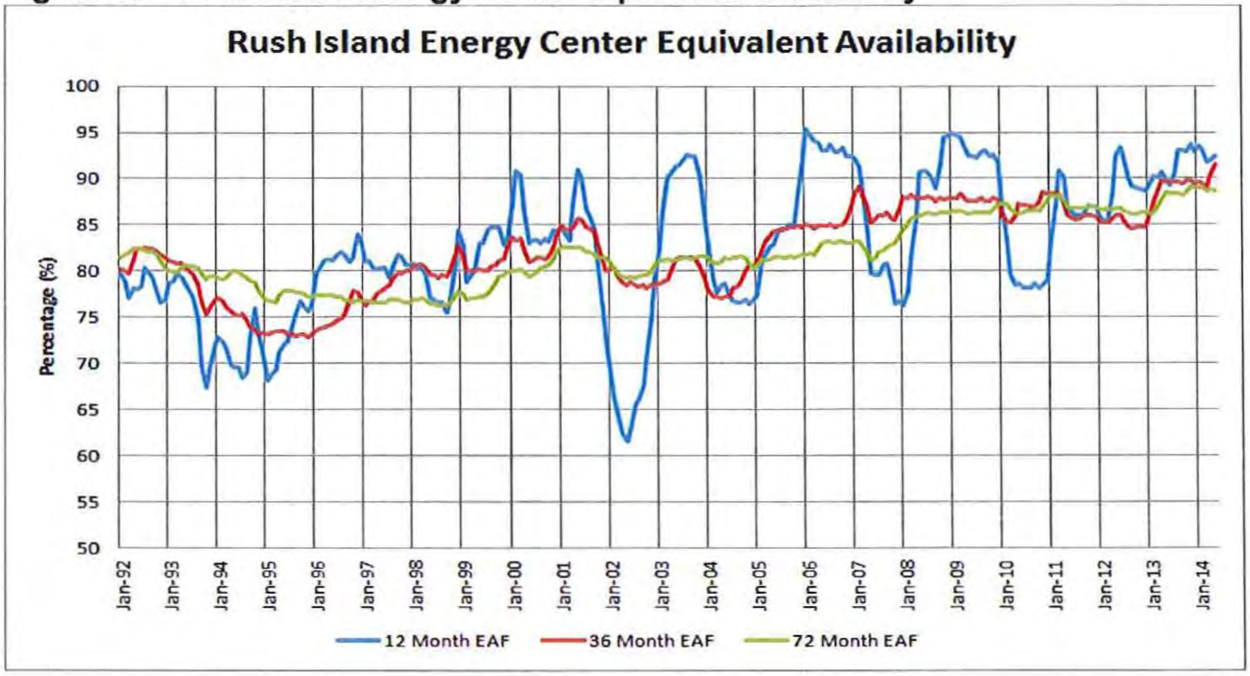
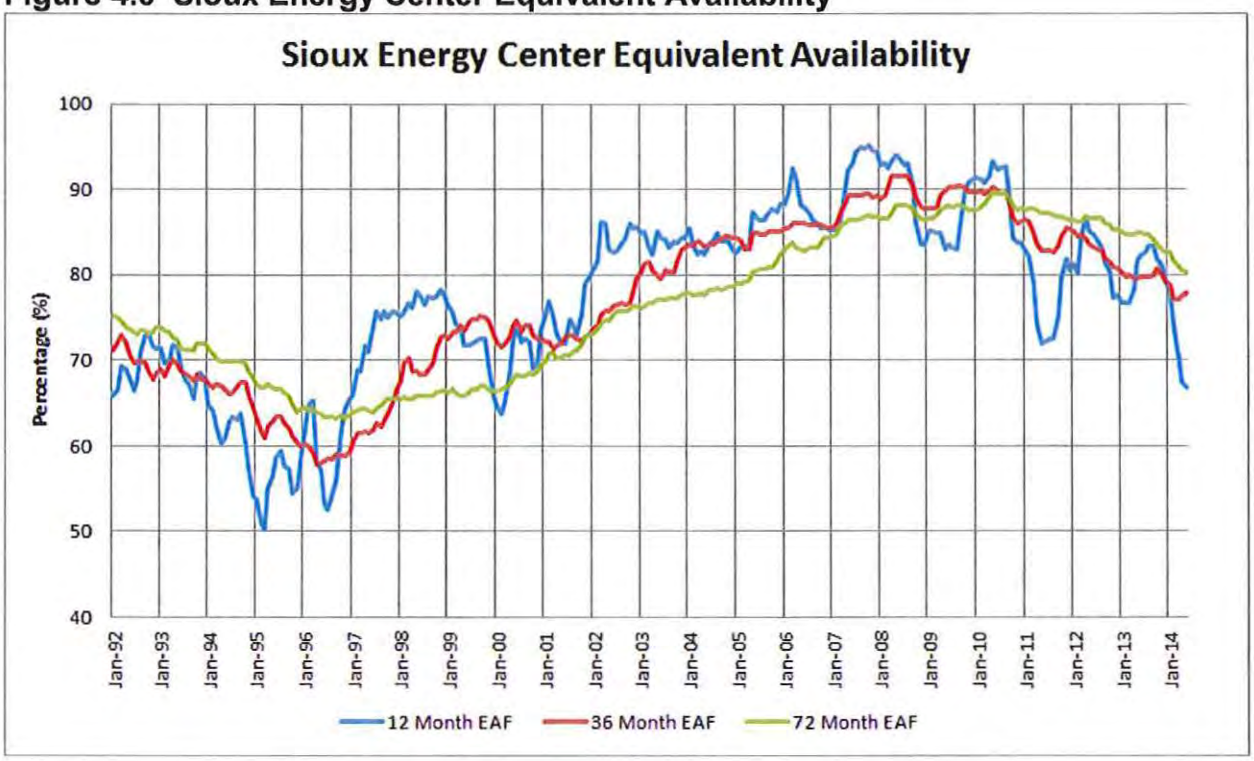


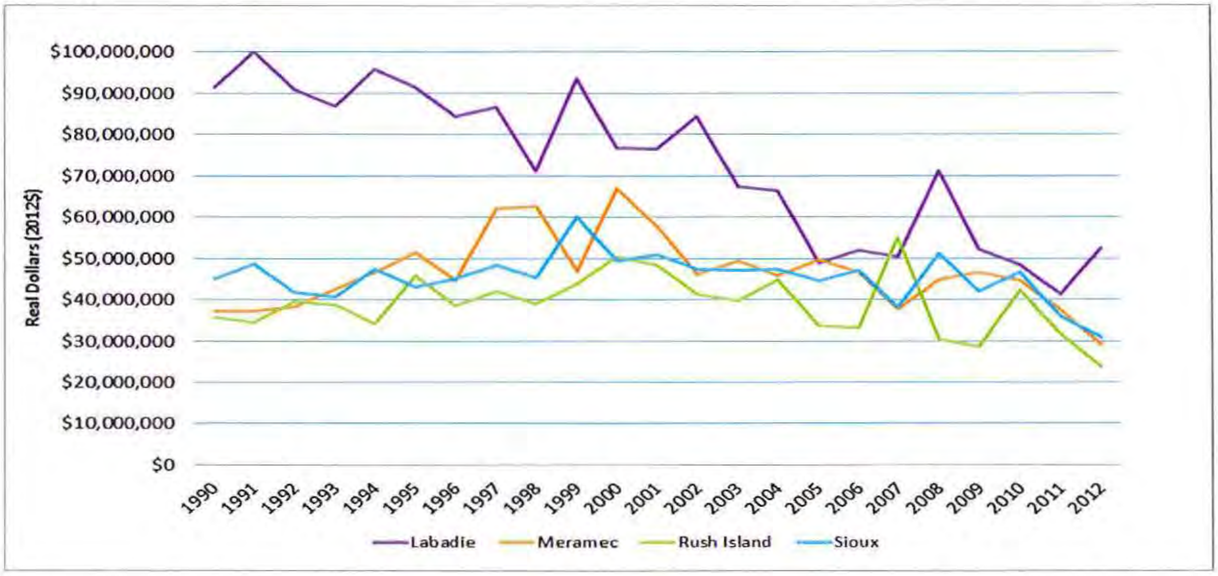
Figure 4.6 Sioux Energy Center Equivalent Availability



4.2.2 Operations and Maintenance Costs

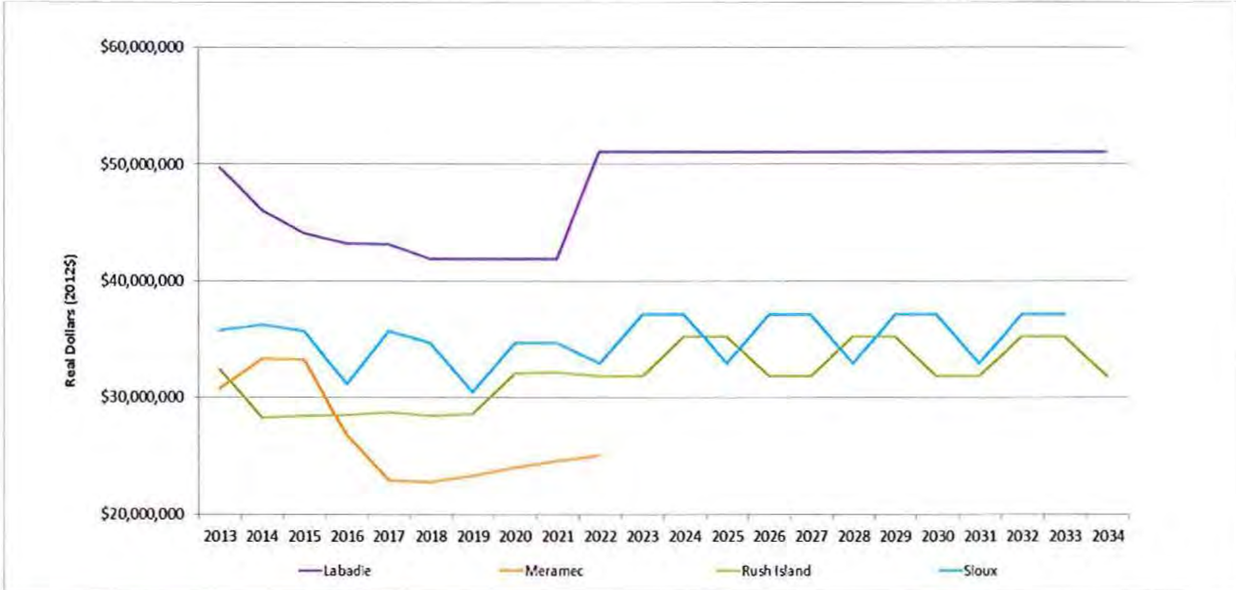
Figure 4.7 shows the historical operations and maintenance (O&M) costs for Ameren Missouri's four coal-fired energy centers from 1990 to 2012. The plant O&M costs were taken from the annual plant operating reports and then normalized to 2012 dollars using the Handy Whitman Index for Total Steam Production Plant. The average annual escalation for the period 1990 to 2012 was 3.3%. These costs are non-fuel O&M expenses. Labadie's O&M decreased and the other energy centers' O&M has remained relatively flat in real terms over the time period with a moderate downward trend in the last 10-15 years. Although the O&M costs were declining or relatively flat, the reliability of the energy centers has remained constant or improved as illustrated in the previous section.

Figure 4.7 Historical Annual O&M for Ameren Missouri Coal Energy Centers (2012$)



The plant O&M costs are anticipated to remain relatively flat to slightly increasing in real terms in the future. Figure 4.8 shows the future O&M costs from 2013 to 2034 in 2012 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 Labadie, Rush Island, and Sioux from 2014 through 2021. A 12 year outage cycle for Labadie and 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 4.8 Future Annual O&M for Ameren Missouri Coal Energy Centers (2012$)



4.2.3 Capital Expenditures

Figure 4.9 shows the historical capital expenditures (environmental and non-environmental) from 2001 to 2012. The plant capital expenditures were taken from the Ameren Missouri accounting system and normalized to 2012 dollars using a 2% escalation rate. Labadie's capital expenditures were relatively flat with the exception of 2012. In 2012, the capital expenditures increased mainly due to a turbine retrofit and electrostatic precipitator (ESP) projects at Labadie to comply with MATS. Meramec's capital expenditures decreased over the time period. Rush Island's capital expenditures remained relatively flat over the time period. Sioux's capital expenditures increased from 2006 to 2010 mainly due to the installation of the WFGD system for SO_2 control.

Figure 4.9 Historic Capital Expenditures Ameren Missouri Coal Energy Centers (2012$)

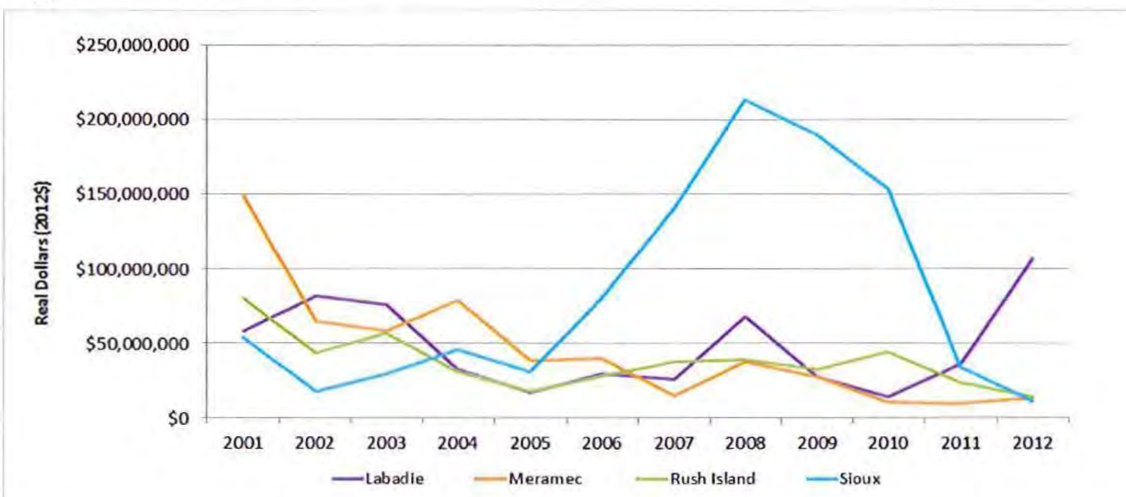
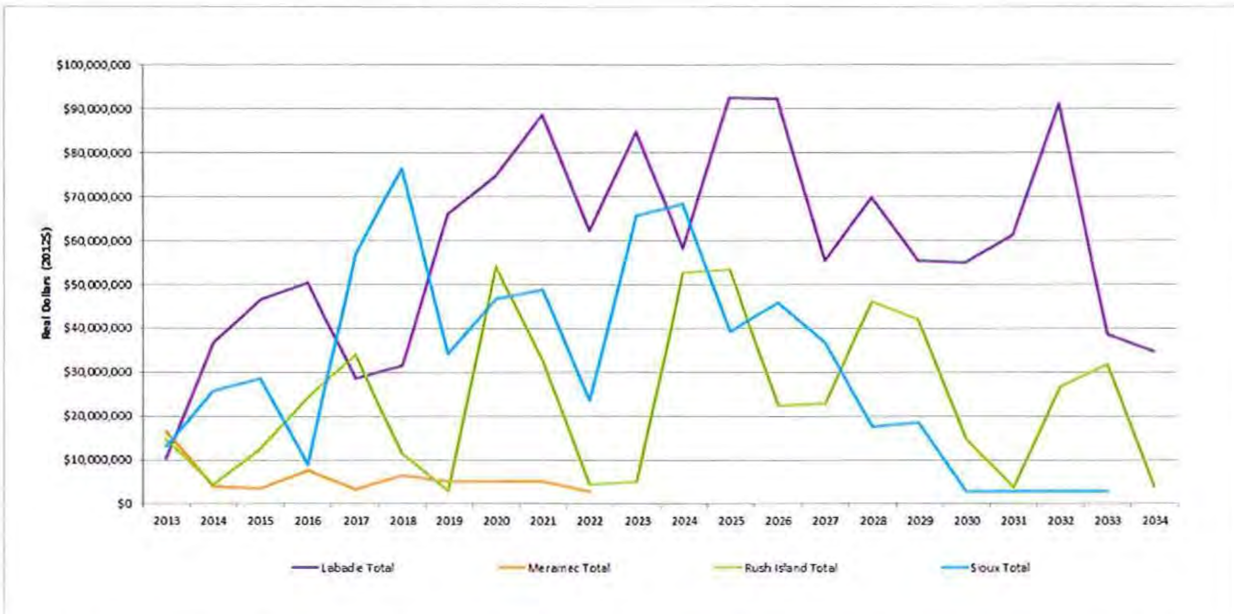


Figure 4.10 shows the future non-environmental capital expenditures for 2013 to 2034. The future environmental capital expenditures are discussed in Chapter 5. The future non-environmental plant capital expenditures were provided by Ameren Missouri Power Operations Services and normalized to 2012 dollars 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 4.10 Future Non-Environmental Capital Expenditures Ameren Missouri Coal Energy Centers (2012$)



4.2.4 Potential Conversion of Meramec Units to Natural Gas-Fired Operation

Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

In 2014, Burns & McDonnell completed a Condition Assessment for the Meramec Energy Center to determine ongoing costs to keep the plant operating safely and reliably through the planning horizon. The Condition Assessment was used to develop the Meramec Options that were evaluated in the alternative resource plans discussed in Chapter 9. Three different Meramec retirement options were considered: 1) retirement by December 31, 2015, 2) retirement by December 31, 2022, and 3) conversion of Units 1&2 to Natural Gas as of December 31, 2015 with Units 3&4 continuing on coal and retirement of all four units by December 31, 2022.

4.3 Potential Expansion of Existing Hydroelectric Resources

4.3.1 Keokuk Hydroelectric Expansion Opportunities

Ameren Missouri retained HDR Engineering, Inc. (HDR|DTA) to evaluate potential expansion options for increasing generation at the Keokuk Hydroelectric Energy Center located on the Mississippi River in Keokuk, Iowa. This included identifying opportunities for increasing performance of the existing generating units, adding generation at the existing powerhouse and/or Lock No. 19 (a navigation lock that is owned and operated by the U.S. Army Corps of Engineers), and possibly adding generating units in the spillway or from a separate powerhouse adjacent to the eastern side of the Keokuk Dam. In 2011, HDR|DTA prepared a report entitled *Keokuk Hydroelectric Project Expansion Study Concept Report* that summarizes the 14 potential expansion options that were evaluated, results, and conclusions.

Seven of the 14 potential expansion options, listed below and retaining the option designations from the HDR|DTA study, were evaluated further with approximate additional generating capacity ranging from 4.5 to 162 MW.

- **Option 1**: Restore/upgrade the two House Units that are currently not operational.
- **Option 2**: Implement draft tube modifications that will increase performance for all fifteen main unit turbines.
- **Option 2a**: Restore/upgrade the two House Units that are currently not operational and implement draft tube modifications that will increase performance for all fifteen main unit turbines.
- **Option 3 (3-5K)**: Use the five spare bays to add generating units (10 MW Kaplan Units).
- **Option 3a-5K**: Restore/upgrade the two House Units that are currently not operational and use the five spare bays to add generating units (10 MW Kaplan Units).
- **Option 3a-15K**: Restore/upgrade the two House Units that are currently not operational and use the 15 spare bays to add generating units (10 MW Kaplan Units).

- **Option 3c-15K**: Restore/upgrade the two House Units that are currently not operational; implement draft tube modifications that will increase performance for all fifteen main unit turbines; and use the 15 spare bays to add generating units (10 MW Kaplan Units).

Table 4.5 provides a summary of the operating and cost characteristics that were evaluated in a levelized cost of energy analysis (LCOE). Cost assumptions from the original HDR|DTA evaluation were reviewed with internal subject matter experts and revised as appropriate.

Table 4.5 Summary of Operating and Cost Characteristics (2013$)

	Option	Additional Capacity (MW)	Additional Average Annual Energy (MWh)	Project Cost ($1,000)	Annual Fixed O&M ($/yr), ($1,000)	Annual Variable O&M ($/yr), ($1,000)	LCOE (¢/kWh)
1	Restore/Upgrade Non-Operational House Units	4.5	18,271	27,151	56	37	15.66
2	Implement Draft Tube Modifications	7.5	5,974	45,554	38	5	77.79
2a	Restore House Units, Implement Draft Tube Modifications	12	22,486	63,359	90	42	28.37
3 (3-5K)	New Units to Spare Bays (Add 5 Kaplan Units)	50	170,408	255,884	255	74	14.96
3a-5K	Restore House Units, Add 5 Kaplan Units	54.5	175,202	272,412	497	111	15.68
3a-15K	Restore House Units, Add 15 Kaplan Units	154.5	372,168	731,491	791	260	19.61
3c-15K	Restore House Units, Implement Draft Tube Modifications, Add 15 Kaplan Units	162	376,104	767,837	554	223	20.84

Based on the *Keokuk Hydroelectric Project Expansion Study Concept Report*, two projects were identified as viable options for further consideration: Option 1 and Option 3. Table 4.5 shows that Option 3 (3-5K) is the least cost option. Therefore, Option 3 (3-5k) was selected for further evaluation in the integration analysis, discussed in Chapter 9.

4.4 Efficiency Improvements[5]

4.4.1 Existing Facility Efficiency Options

Ameren Missouri has implemented various initiatives to improve efficiency and reduce greenhouse gas (GHG) emissions at its existing facilities. These initiatives include replacement of incandescent light bulbs with compact fluorescent light bulbs, and standardization on low-energy usage light fixtures during system replacements. Another initiative to improve efficiency and reduce GHG emissions in the operation of

[5] 4 CSR 240-22.040(1)

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. In 2011 and 2012, Ameren Missouri completed several energy efficiency projects that will reduce energy consumption by more than 1,000 MWh annually and reduced carbon dioxide (CO_2) emissions by more than 870 metric tons annually (assuming 0.73 metric tons of CO_2 per 1 MWh). Ameren Missouri will continue assessing and implementing the projects that prove to be feasible on an ongoing basis.

Ameren Missouri has been proactive in monitoring the status of light-emitting diode (LED) technology. The company engaged EPRI to conduct a pilot program, testing 11 street lights in the city of Ballwin, Missouri beginning in 2009 and lasting approximately 36 months. This pilot, part of a larger, national effort, provided key insights into the performance of LED street and area lighting (SAL) technology. While there were multiple findings from the EPRI study, there are a few important observations to note:

- **Reliability** – EPRI uncovered multiple issues with the products submitted in the demonstration project including failures directly "out of the box" from the manufacturer, failures caused by faulty circuitry, LED driver failure, and manufacturer recalls.
- **Varying Power Draw Compared to Specifications** – EPRI discovered that many of the manufacturers' claims on power draw were optimistic and inconsistent with their field testing results.
- **Good light distribution** – LEDs were able to produce lighting patterns more uniformly than existing lighting technologies.

EPRI's study indicated that the LED SAL technology was "ready for energy efficiency programs for utilities." Given EPRI's findings, Ameren Missouri undertook a study of the economics of replacing its existing street lighting system with LEDs (Company owned street lights which represent greater than 90% of the street lights on Ameren Missouri's system). Ameren Missouri conducted multiple analyses to evaluate the economics of LED street lighting facilities and also conducted multiple risk analyses to provide more insight into the results. The overall conclusion is that while LEDs appear to be a viable technology, current economics and associated uncertainty do not support near-term adoption. Ameren Missouri will continue to monitor the various critical assumptions identified through this analysis, and will update the analysis as needed.

4.4.2 Existing Energy Center Efficiency Options[6]

In 2009, Ameren Missouri recognized the potential for end-to-end energy efficiency improvements, and engaged EPRI to undertake a study to identify, quantify, and prioritize energy efficiency project opportunities across its operations in electricity generation, transmission, distribution, and utilization at Ameren Missouri facilities. A team developed profiles of 37 candidate generation project types, which were screened on a unit-by-unit basis on technical applicability. The LCOE was calculated for the remaining 28 project types after the first screening.

In 2010, a team composed of Power Operations Support personnel further reviewed the 28 potential project types at Ameren Missouri's coal-fired energy centers and selected several for implementation. These projects included:

- Operation of both Sioux Energy Center units in partial arc operation
- Precipitator power optimization at Labadie Units 3&4
- Circulating water system improvements at Meramec Energy Center
- Circulating water debris filters and ball cleaning system installation on Labadie Unit 4
- Turbine spill strip restoration on Rush Island Unit 1

All of the above projects have been implemented successfully and each has contributed to improved efficiency on the respective units. These plant energy efficiency projects allow for a potential reduction in CO_2 emissions at the energy centers. For example, high pressure turbine efficiency improved by over 4% on Rush Island Unit 1 following the outage in which the turbine spill strips were restored. Operation of the Sioux units in partial arc operation is expected to increase efficiency by approximately 0.4% on each unit. The circulating water debris filters and ball cleaning system on Labadie Unit 4 has led to the highest condenser cleanliness factors at the energy center without the need to perform labor-intensive mechanical cleaning on the unit.

Ameren Missouri is in the process of replacing aging feedwater heaters at several energy centers. In 2012, Labadie replaced 10 feedwater heaters. Additional feedwater heater replacements are scheduled at several coal-fired energy centers over the next several years. Issues with aging feedwater heaters, such as tube leaks and excessive tube plugging, can cause large efficiency reductions. In addition, Ameren Missouri monitors and reports on efficiency at each coal-fired energy center on a periodic basis in an effort to maintain acceptable heat rate performance.

[6] 4 CSR 240-22.040(1)

As of 2012, the successful implementation of the above-mentioned projects, as well as other efforts, helped Ameren Missouri reduce heat rate by over 0.8% from a 2009 baseline. Ameren Missouri will continue assessing and implementing projects that look feasible on an ongoing basis.

4.5 Compliance References

5. Environmental Compliance

Highlights

- *The U.S. Environmental Protection Agency continues to aggressively pursue more stringent regulations of power plant air, water, and solid waste emissions.*
- *Existing and potential new environmental regulations could potentially affect the operations of Ameren Missouri's Energy Centers; in particular its coal fired units.*
- *Ameren Missouri has identified mitigation steps and costs for complying with current and probable future environmental regulations to be used in its evaluation of alternative resource plans.*

Ameren Missouri has made significant investments to comply with existing environmental regulations. However, in addition to existing laws and regulations, the EPA is developing environmental regulations that will likely have a significant (though undetermined at this time) impact on the electric utility industry. These regulations may prove to be particularly burdensome for certain companies, including Ameren Missouri, which operate coal-fired energy centers. Significant new rules proposed or promulgated since the beginning of 2010 include the regulation of greenhouse gas emissions; revised national ambient air quality standards for fine particulate, SO_2, and NO_2 emissions; the Cross State Air Pollution Rule (CSAPR), which requires further reductions of SO_2 emissions and NO_x emissions from energy centers; a regulation governing management of coal combustion residuals (CCR) and coal ash impoundments; the Mercury and Air Toxics Standards (MATS) rule, which requires reduction of emissions of mercury, toxic metals, and acid gases from energy centers; revised NSPS for particulate matter, SO_2, and NO_x emissions from new sources; the ELG rule, which may require the construction of waste water treatment facilities; and new regulations under the Clean Water Act that may require significant capital expenditures such as new water intake structures or cooling towers at our energy centers.

The EPA has proposed CO_2 limits for new, modified and existing coal-fired and natural gas-fired combined cycle units. These new, proposed regulations, if ultimately enacted, are likely to be litigated. As such, their ultimate implementation (including timing) is uncertain.

Environmental regulations are an important factor to consider in resource planning. In this IRP, it is assumed that construction of a new coal fired power plant would require carbon capture and sequestration (CCS) in addition to measures required for compliance with other existing, proposed, and potential environmental regulations.

Additionally, questions remain about the impacts of proposed and potential environmental regulations, including those limiting emission of greenhouse gases, on Ameren Missouri's existing generation fleet, especially its coal-fired generation assets.

This chapter presents the current major regulations affecting the power industry as well as proposed and potential new environmental regulations that are expected to be enacted during the planning horizon. The Environmental Protection Agency (EPA) has recently issued, and in the near future is expected to issue and finalize, new environmental regulations related to air emissions, coal ash waste, and water. Ameren Missouri has incorporated assumptions regarding such proposed and potential environmental regulations into its reference case and a corresponding compliance path characterized by environmental retrofits to its existing fleet. The costs and timing of those retrofits are reflected in the risk analysis presented in Chapter 9 and are instrumental in particular in the retirement analysis of the Meramec Energy Center. Furthermore, the planning scenarios act as a signpost for decision making and therefore are an important aspect of the strategy selection in Chapter 10.

5.1 Overview

Ameren Missouri is subject to various environmental laws and regulations enforced by federal, state (Missouri and Illinois) and local authorities. The following paragraphs identify the major federal environmental laws governing the operations of Ameren Missouri facilities. The State of Missouri, State of Illinois, and local authorities are also charged with the enforcement of environmental laws and/or ordinances which are intended to implement various provisions of the federal statutes. In addition, a summary of possible future environmental initiatives that could affect the power industry is included.

Given the lack of certainty regarding the enactment of proposed regulations combined with the lack of specificity of regulations, which are under development but for which no proposed rule has been issued, Ameren Missouri has necessarily made certain good faith assumptions regarding potential future compliance measures.

5.2 Major Environmental Laws

5.2.1 Current Laws

Clean Air Act (1970, 1977 & 1990)

The Clean Air Act (CAA) established Ambient Air Quality Standards for SO_2, NO_x, particulate matter (PM), fine particulate matter (PM 2.5), ozone, carbon monoxide (CO) and lead. Ambient standards are required to be evaluated by the U.S. EPA on a 5 year cycle. The U.S. EPA continues to pursue more stringent ambient standards through this process. Ambient Standards are managed through emission limits, emission trading programs, ambient air monitoring, and air quality modeling conducted by each state as part of State Implementation Plans (SIP). The air quality in each state is analyzed and designated as Attainment or Nonattainment with the standard for each pollutant. Nonattainment areas are subject to increased pollution control measures.

The CAA also established:

- New Source Performance Standards (NSPS) for determining the pollution control requirements for new sources, including existing sources that become subject to new source requirements due to a "modification" as defined by the statute and relevant rules;
- National Emission Standards for Hazardous Air Pollutants (NESHAPS) for control of asbestos and other hazardous air pollutants, defining a process to set Maximum Achievable Control Technology (MACT) Standards for these air pollutants;
- New Source Review (NSR) programs that mandate review to determine if projects trigger permitting and additional pollution control equipment requirements;
- Prevention of Significant Deterioration (PSD) program, which imposes control requirements on new and modified major sources to protect ambient air quality. The NSR and PSD programs do not apply to various actions at existing major sources, including routine repair & replacement of equipment, and changes which do not increase emissions; and
- The Acid Rain Program.

Acid Rain Program

The Acid Rain Program established a national cap-and-trade program for SO_2 emissions from generating units, established NO_x emission limits for different boiler types, i.e., tangential fired vs. cyclone fired units, and required the installation of Continuous Emissions Monitors (CEM) on all coal-fired power plants to measure SO_2, NO_x, oxygen (O_2) and carbon dioxide (CO_2) on a continuous basis.

The Acid Rain Program required an SO_2 emissions cap of 15,000,000 tons in 1995 reduced to 10,000,000 tons in 2000 and to 8,950,000 tons in 2010. In addition, existing generating units are issued thirty (30) years of SO_2 allowances (1 allowance = 1 ton of SO_2 emissions). The SO_2 allowances can be bought, sold, traded, or banked. Three percent of the SO_2 allowances were held back and available for purchase at an annual EPA SO_2 auction. These allowances have a perpetual shelf life, under current regulations.

Clean Air Interstate Rule (CAIR)

Promulgated in March 2005, CAIR established a new cap-and-trade program with a reduction in emission allowances on annual SO_2 and seasonal NO_x emissions from electric generating units, as well as a new cap and trade program for annual NO_x emissions. CAIR is a regional program and applies to electric generating units in 28 eastern states and the District of Columbia. For SO_2 emissions, CAIR uses allowances from the Acid Rain Program and establishes a cap of 5,000,000 tons nationally by 2010 and a cap of 3,500,000 million tons by 2015. CAIR has a two phase program for NO_x emissions; where NO_x emissions are capped <u>annually</u> and <u>seasonally</u> in the 28 state CAIR region. Phase 1 began in 2009 and Phase 2 is scheduled to begin in 2015. Prior to CAIR, the NO_x Budget Trading Program had created a seasonal NO_x emission cap and trade program for twenty-two (22) eastern states including eastern Missouri. The NO_x Budget Trading Program set a lower ozone season (May – September) cap on NO_x emissions by state and created NO_x allowances for the ozone season each year. CAIR is still in place pending a Court decision on the CSAPR that is described in the following section.

Cross State Air Pollution Rule (CSAPR)

On July 6, 2010, the EPA proposed a rule which would replace the 2005 CAIR. A December 2008 court decision kept the requirements of CAIR in place temporarily but directed the EPA to issue a new rule to implement the Clean Air Act requirements concerning the transport of air pollution across state boundaries. Initially a Clean Air Transport Rule (CATR) was developed in response to the court's concerns. The current rule, called the Cross State Air Pollution Rule (CSAPR), was finalized on July 6th, 2011. The CSAPR includes the same annual SO_2 and NO_x programs, as well as seasonal NO_x trading programs, as the CAIR. However, the CSAPR establishes new allowances for the annual NO_x and SO_2 programs and the seasonal NO_x program. Allowances for the CAIR trading programs cannot be used for the CSAPR trading programs. Several states including Missouri are designated as "Group 1" states in the rule, and SO_2 emission allowances are further reduced in Group 1 states beginning in 2014. The two programs, CAIR and CSAPR, are structured differently. CAIR uses the Acid Rain SO_2 allowances and thus allows Ameren Missouri to utilize its sizable SO_2 allowance bank. Also, it includes surrender ratios which are currently 2-for-1 and would become 2.86-for-

1 beginning in 2015 if it were to remain in effect at that time. CSAPR uses newly created allowances and thus there is no bank to rely on for any potential shortfall. Based on the surrender ratio, compliance with CAIR creates a lower limit relative to the CSAPR. However, Ameren Missouri's current bank and the national bank of allowances make compliance with CAIR less challenging as the current price is less than $2 to offset a ton of SO_2 emissions. CSAPR was accompanied by much higher prices and included variability limits which control the amount of allowances that may be purchased and used for compliance.

CSAPR was slated to become effective January 1, 2012, but the rule was stayed by a federal court decision on December 30, 2011, in response to several legal challenges. On August 21, 2012, the D.C. Circuit Court of Appeals (D.C. Circuit) vacated CSAPR, directing EPA to continue to administer CAIR and to move "expeditiously" to finalize a replacement transport rule. The EPA appealed this ruling to the U.S. Supreme Court, which subsequently reversed the DC circuit opinion vacating CSPAR on April 29, 2014. On June 26, 2014, the EPA filed a motion with the U.S. Court of Appeals for the D.C. Circuit to (1) remove the stay of CSPAR and (2) delay for three years all of the compliance deadlines that had not already passed when the stay was enacted. In the interim, CAIR remains in place. If approved, the delays would result in phase 1 emission budgets applicable in 2015 and 2016 and phase 2 budgets applicable in 2017 and beyond.

Other Clean Air Act Provisions

Section 126 of the CAA allows downwind states to file petitions against upwind states to control emissions in order to achieve attainment with ambient air quality standards.

The Regional Haze Rule is another provision of the CAA. The goal of the Regional Haze Rule is to set visibility equivalent to natural background levels by 2064 in Class I areas. Class I areas are defined as national parks exceeding 6,000 acres, wilderness and national memorial parks exceeding 5,000 acres and all international parks in existence on August 7, 1977. There are currently 156 Class I areas, two of which are in the State of Missouri (Hercules Glade and Mingo). In addition, the Regional Haze Rule is the basis for Best Available Retrofit Technology (BART) rule setting SO_2 & NO_x control requirements for certain large emission sources and Energy Centers in each state.

Maximum Achievable Control Technology (MACT) Standards to Control Mercury and Other Hazardous Air Pollutants

Title III of the Clean Air Act Amendments of 1990 included a requirement for the EPA to establish Maximum Achievable Control Technology (MACT) standards for 188 hazardous air pollutants identified in the Act. A MACT standard essentially requires the application of emission controls that are no less stringent than the emission control that is achieved in practice by the best controlled similar source in commercial operation. The Clean Air Act mandates that compliance with a MACT standard is required within three years of the final rule. The EPA has established MACT standards for numerous source categories including reciprocating internal combustion engines and cement kilns.

In 2005, the EPA promulgated the Clean Air Mercury Rule (CAMR), which established a cap and trade program and defined the mercury monitoring and control requirements for coal-fired power plants over the following ten years. In 2008, the rule was vacated by the DC Circuit and remanded to the EPA. The EPA petitioned the U.S. Supreme Court to challenge this ruling. However in 2009, with the change in Administrations, this challenge was dropped.

With the vacatur of the CAMR, EPA began the development of a replacement rule –the Maximum Achievable Control Technology (MACT) standard for mercury and other hazardous air pollutants. EPA was subsequently required by a consent decree to propose regulations by March, 2011, and finalize regulations in November, 2011. The final rule was effective on April 16, 2012.This final rule is known as the Mercury and Air Toxics Standards (MATS). Compliance with the standards is required by April 16, 2015, although the permitting authority can grant a one-year extension on a case-by-case basis. The MATS includes standards for mercury, particulate matter as a surrogate for non-mercury metals, hydrogen chloride (HCl) as a surrogate for acid gases, work practices for organic emissions and monitoring requirements. The MATS standard also includes emission limits for new sources which are significantly tighter than for existing sources.

Ameren Missouri plans to utilize Activated Carbon Injection technologies and/or fuel additives and other sorbents to control mercury emissions. Other options are available depending on coal type including co-benefit control from Flue Gas Desulfurization (FGD) and other emerging multi-pollutant technologies.

The EPA has also included MACT standards for other hazardous air pollutants, such as non-mercury metals and acid gases, and work practice standards for organic compounds. Additional technology may be required to control such emissions. Depending on fuel type, EGUs could install additional pollution control equipment including Flue Gas Desulfurization (FGD) (commonly referred to as "scrubbers") for acid gases (HCl), and particulate controls such as electrostatic precipitators (ESP) or fabric filters ("bag houses") for non-mercury trace metals including arsenic, chromium, lead and nickel. The EPA has conducted an extensive information collection effort to obtain emission data from existing units and used that information to set the standard for each hazardous air pollutant.

Revisions to the National Ambient Air Quality Standard (NAAQS) for Fine Particulate (PM2.5)

On Feb. 24, 2009, the D.C. Circuit Court of Appeals remanded to EPA several aspects of its 2006 decisions on the PM2.5 NAAQS. The Court stated that the EPA had not provided a legally sufficient explanation for its decision to keep the existing annual primary standard of 15 $\mu g/m^3$. As a result of the decision, the EPA folded its response to the remand into the next regular review of the NAAQS. The EPA announced a schedule that called for a proposal to revise the annual PM2.5 standard in February, 2011 and for a final rule in October, 2011, to satisfy the 5-year review requirement of the CAA. On June 15, 2012 the EPA proposed to lower the ambient standard to a range of 12 – 13 $\mu g/m^3$. The final rule was signed on December 14, 2012 and set the standard at 12 $\mu g/m^3$. States were required to submit their recommendations on classifications by December 14, 2013. EPA will finalize these designations by December 12, 2014 with compliance by 2020. A state may request a 5 year extension with compliance in 2025 if approved by EPA.

Revisions to the National Ambient Air Quality Standard (NAAQS) for NO2

On January 22, 2010, the EPA revised the primary NAAQS for NO_2 by adding a one-hour 100 ppb standard. Because the EPA's main health concern was NO_2 concentrations attributable to mobile sources, the revisions included requirements for an expanded near-road NO_2 ambient monitoring network. However the standard also had an immediate impact on stationary sources seeking preconstruction permits. Attainment designations were made on January 20, 2012 and the entire US was designated as "unclassifiable/attainment", meaning that actual monitored data showed attainment or there was not sufficient data at this time to make an affirmative determination (unclassifiable). At this time the regulatory requirements for unclassifiable areas are the same as attainment areas. No areas within the U.S. were designated as nonattainment based on the 2008-2010 data. If an area within a state becomes nonattainment the state is required to submit attainment plans within 3 years of such designation. Compliance with the new NO_2 ambient standard would be required within 5 years of designation as nonattainment.

Revisions to the National Ambient Air Quality Standard (NAAQS) for Ozone

The EPA lowered the ambient standard for ozone from 85 ppb to 75 ppb in 2008. In January, 2009, the EPA proposed to lower the standard to a range between 60 ppb and 70 ppb. EPA was required to finalize nonattainment designations for the 2008 standard in March, 2010. However the EPA granted a petition for reconsideration in September, 2009, and proposed to lower the standard in January, 2010. The EPA originally planned to finalize the revision by the end of August, 2010, but extended that date to December, 2010. On December 8, 2010, the EPA proposed to delay the final rule until July 2011. The EPA announced in July 2011 that the revisions to the standard would be delayed until 2013 and that the current 75 ppb standard would be implemented. It should be noted that EPA Staff issued a recommendation on August 29, 2014, that these standards be further tightened between 7 and 20 percent.

Implementation of the existing standard starts a new round of nonattainment designations and subsequent state attainment plans for future controls. Attainment designations were made in 2012; attainment demonstrations are due in 2015 and attainment is required from 2015 to 2032 depending on the severity of the nonattainment classification. Six classifications range from marginal to extreme based on the current ambient air quality. In Missouri, Franklin, Jefferson, St. Charles, and St. Louis Counties and St. Louis City are designated as marginal nonattainment with attainment required in 2015. The rest of the state is designated as unclassifiable/attainment.

Revisions to the National Ambient Air Quality Standard (NAAQS) for SO2

The EPA adopted an SO2 ambient standard of 75 ppb on June 2, 2010. The EPA also revoked the annual and 24-hour SO2 NAAQS. The Missouri Department of Natural Resources (MoDNR) recommended three non-attainment areas, based on monitoring data: areas around Springfield, Kansas City and Herculaneum. Attainment designations were finalized on August 5, 2013, designating the areas around Kansas City (portions of Jackson County) and Herculaneum (portions of Jefferson County) as nonattainment. All states were required to submit "Infrastructure" State Implementation Plans by June 2013. States with non-attainment areas are required to submit attainment plans by April 6, 2015. Compliance with the new SO2 standard is required no later than October 4, 2018. The EPA is evaluating the adoption of a new approach for determining compliance with the new SO2 standard. The EPA has conducted focused stakeholder meetings to gather more input on modeling versus monitoring. As a result of these meetings EPA has proposed a Data Requirements rule that would allow states to address large sources of SO2 with either modeling or monitoring. For areas where states choose modeling to determine attainment status, states must submit their designations (and supporting information) to EPA by January 13, 2017. US EPA will designate these areas either attainment or nonattainment by December 2017. Nonattaining areas must be in compliance by December 2022. For areas where states choose monitoring, states must submit monitoring plans to EPA by July 2016 and have monitors installed by January 1, 2017. After 3 years of monitoring data is collected (2017-19) the states must certify the data collected by May 2020. US EPA will designate these areas either attainment or nonattainment by August 2020. Nonattaining areas must be in compliance by August 2025. Because of the conservatism of the EPA's models and modeling requirements, for states selecting modeling for areas not yet designated it is likely that these areas will be determined to be in nonattainment and require additional controls for power plants.

White House Climate Action Plan

On June 25, 2013, President Obama presented his Climate Action Plan directly targeting carbon dioxide emissions from domestic power plants. The plan was described as, "an all-of-the-above approach to develop homegrown energy and steady, responsible steps to cut carbon pollution," in order to, "leave a cleaner, more stable environment for future generations."

The President directed the EPA to issue a new proposed rule regarding carbon emission standards for new generation resources by September 20, 2013. The proposed rule was published in the Federal Register on January 8, 2014. If subsequently enacted as a final rule, it would establish separate standards for coal-fired and natural gas-fired resources. The proposed standards require new coal-fired resources to control carbon dioxide emissions to a level about 50% less than that achieved by current advanced facilities and assume the use of carbon capture technology. There is significant debate regarding whether such technologies meet the requirements set forth in the Clean Air Act (that they be commercially demonstrated prior to adoption), and it is reasonable to assume that it will be challenged in the courts if adopted.

The President also directed the EPA to propose rules for modified, reconstructed, and existing power plants no later than June 1, 2014, with finalization of the rule no later than June 1, 2015. The EPA issued their proposed rules for both existing sources and modified or reconstructed units on June 2, 2014. This plan is discussed in the following section.

While we cannot predict the exact effect of these new standards and rules until such time that they are fully enacted, it is reasonable to assume that they will:

(1) likely discourage investment in new coal fired generation resources, if not virtually eliminate coal fired generation as a viable new resource option until carbon capture and storage technology is demonstrated as a cost-effective technology.

(2) increase the relative cost of existing fossil fuel-fired resources (and coal-fired resources in particular), and as a consequence impact the market price of energy, though we do not know to what extent either is impacted, individually or in relationship to each other or the cost of alternatives.

Regulation of Greenhouse Gases (GHG) under the CAA

In April, 2007, the U.S. Supreme Court issued a decision that the EPA has the authority to regulate CO_2 and other greenhouse gases from automobiles as "air pollutants" under the CAA. This decision was a result of a Bush Administration ruling denying a waiver request by the state of California to implement such regulations. The Supreme Court sent the case back to the EPA, to conduct a rulemaking process to determine whether greenhouse gas emissions contribute to climate change "which may reasonably be anticipated to endanger public health or welfare." In late 2009, the EPA issued a finding that greenhouse gases contribute to air pollution that may endanger public health or welfare. As a result of that finding, the EPA subsequently issued the Tailoring Rule which would delay the need for smaller sources to control CO_2 emissions. The rule became effective on January 2, 2011. On June 26, 2012, the D.C. Circuit ruled to uphold several EPA GHG rules, including the endangerment findings and the Tailoring Rule. All challenges to the rules were either denied or dismissed by the D.C. Court. On October 15, 2013 the Supreme Court granted cert petitions from 6 petitioners on whether regulation of GHG from motor vehicles triggered GHG permitting requirements for stationary sources. On June 23, 2014, the U.S. Supreme Court ruled that the EPA exceeded its statutory authority under the Clean Air Act in determining that stationary source emissions of GHG's would trigger permitting obligations. However, they upheld those portions of the rulemaking requiring a source to apply "best available control technology" ("BACT") to GHG emissions when the source otherwise triggers permitting due to emissions of other pollutants (referred to as "anyway" sources). The Court's decision was limited to the EPA's regulation of GHG under the Prevention of Significant Deterioration program and Title V of the CAA.

On December 23, 2010, the EPA announced a Settlement Agreement with states and environmental groups regarding setting greenhouse gas (GHG) new source performance standards (NSPS) for new and existing coal-, gas- and oil-based power plants. Pursuant to this settlement, EPA planned to rely on a little used provision of the Clean Air Act, Section 111(d), which gives EPA the authority to establish performance standards to reduce emissions for which there is no ambient standard. The EPA has made it clear it wants the states to take the lead on establishing the GHG emission standards for existing power plants, and for the states to have considerable flexibility. It should be noted that EPA's intent by this action is to have existing power plants reduce CO_2 emissions, presumably through energy efficiency or other Energy Center modifications or operating restrictions. EPA originally planned to propose standards for both new and modified boilers under Clean Air Act section 111(b) and for existing facilities under section 111(d) by July 26, 2011, and finalize the rules by May 26, 2012. A proposed new source performance standard for new units was issued in May 2012 and was open for public comment until June 25, 2012, but was withdrawn. A revised standard for new units was issued on September 20, 2013 in pre-publication format and published in the Federal Register on January 8, 2014.

As noted above, the EPA issued their proposed "Clean Power Plan" on June 2, 2014, with comments due by October 16, 2014. This date was subsequently extended to December 1, 2014 for existing sources. These proposed rules apply to existing carbon emitting resources. The plan has two primary components: (1) state-specific, emission rate-based reduction targets; and (2) specific guidelines for states to utilize in developing and implementing compliance plans. Under the proposal, these rules would be due in June 2016, though there are provisions for up to a two year extension. The proposed rule provides flexibility to the states in the development of their compliance plans, including their ability to join with other states to develop a regional compliance approach.

5.3 Water Environmental Laws

5.3.1 Current Laws

Clean Water Act (Amended 1972)

The Clean Water Act (CWA) establishes pollutant-specific water quality standards for various water bodies and groundwater. In addition, the CWA includes provisions to prevent degradation of higher quality waters. This includes a regulatory program covering Total Maximum Daily Load (TMDL) of "pollutants" allowed into waters of the state. Protection of water resources for industrial facilities typically occurs through the National Pollutant Discharge Elimination System (NPDES) permit process. Technology and water quality based effluent limitations are applied to ensure water quality standards are met. In order to meet permit conditions it may be necessary to modify operations or install additional water pollution control equipment to meet a pollutant specific water standard.

Clean Water Act, Section 316(a) Thermal Discharges

Section 316(a) of the CWA requires limitations on thermal discharges from power plants and other industrial sources.

Energy Center cooling water discharges are regulated by the EPA and Missouri Department of Natural Resources (MODNR) through the NPDES permit program. Currently the State of Missouri and the EPA are working on new NPDES permits for Ameren Missouri Energy Centers. Early indications suggest the resulting proposed revisions to thermal effluent permit limitations and/or state water quality temperature standards during periods of high ambient river temperatures or low flow conditions, may present a compliance challenge. If these potential revisions to the limitations cannot be met in the current configuration, a variance may be sought through section 316(a) of the CWA, or the facility may be required to install cooling towers. The pursuit of a 316(a) variance would require environmental field studies focused on aquatic impacts coupled with an evaluation of hydrologic/thermal modeling of cooling water plume characteristics. If a 316(a) variance demonstration is not successful, existing Energy Centers could potentially be required to reduce generation under certain operating conditions, or undertake infrastructure retro-fits to accommodate the installation of cooling towers. Cooling tower retro-fits will require substantial engineering, design and construction, including possible replacement of condensers. Property acquisition may be necessary at some locations. If ultimately installed, cooling tower installations would be anticipated to increase parasitic load requirements and decrease overall Energy Center efficiency.

Clean Water Act, Section 316(b) Entrainment and Impingement of Aquatic Organisms

Section 316(b) of the CWA was established to protect fish and other aquatic habitat from detrimental impacts associated with water intake structures. At energy centers, aquatic organisms can be impinged (e.g. trapped or pinned against the intake screens) and entrained (e.g. pass through the screens, enter the heat exchanger and then discharged) within cooling water intake structures/piping and condenser systems. The EPA and MODNR establish rules to limit adverse impacts associated with cooling water intake structure operation through the NPDES permit process. Rules can take the form of performance and/or design criteria, or the utilization of specific control technologies. The impingement and entrainment of threatened or endangered species at a cooling water intake structure can also result in the need for additional operational and physical changes.

The EPA has revised Section 316(b) regulations as a result of court challenges to the rule which culminated in Supreme Court decisions in December, 2008, and April, 2009. These new rules were proposed in the Federal Register as of April 20, 2011. The EPA secured additional time under a modified settlement agreement to finalize standards, with final action that was to occur on January 14, 2014. The EPA ultimately issued pre-public notice of the finalized standards on May 19, 2014 and it was published in the Federal Register August 15, 2014. While the rules do not require the installation of cooling towers at all facilities, they are expected to result in significant capital expenditures for advanced control technologies to achieve compliance. Facilities withdrawing in excess of 125 million gallons of water per day will be required to perform studies to determine what control technologies are required. Generation owners are provided the option of selecting one of seven different compliance options. These options include: (1) closed cycle cooling; (2) 0.5 ft/sec through-screen velocity (by design); (3) 0.5 ft/sec through-screen velocity (as measured); (4) existing off-shore velocity cap; (5) modified traveling water screens (TWS); (6) a "suite of technologies" determined by the permit writer to represent the best available technology; or (7) any technology that results in an annual impingement mortality rate of less than 24%. The standards also include requirements for the reduction of intake flow similar to a closed cycle system for new units which increase an existing generation station's capacity.

Clean Water Act-Wetlands

Construction projects involving "dredge and fill" (earth disturbance) within identified wetlands/streams can require mitigation, based on the total number of acres impacted. Mitigation involves establishment of replacement wetlands at a ratio of anywhere from 1:1 up to 4:1.

Clean Water Act-Spill Prevention Control and Countermeasures (SPCC) Program

The CWA requires spill prevention plans and containment systems be developed for substations and bulk oil storage containers/tanks where 1,320 gallons of oil or more in aggregate are present and there is potential for discharge into surface water. These EPA rules have been revised to clarify that electrical equipment is subject to these rules. Ameren Missouri has about 650 substations in Missouri that may be subject to these rules. Ameren Missouri has developed a program to assess the risk of oil spills to surface waters for these locations and install containment measures where needed.

Safe Drinking Water Act (1974)

The Safe Drinking Water Act was established to protect the quality of drinking water. The Safe Drinking Water Act establishes monitoring frequency and standards for contaminants and requires public notifications and corrective actions when standards are exceeded. MODNR is the lead agency charged with establishing regulations and enforcing compliance.

5.3.2 Possible Future Water Environmental Initiatives

Clean Water Act, Effluent Guideline Limitations Revisions

Effluent guidelines are periodically updated by the EPA to ensure best available technology is utilized in the treatment of waste water from any steam electric power plants, including fossil, nuclear and combined cycle units. The existing steam electric effluent guidelines were last revised in 1982. The EPA conducted a detailed study report in 2008 and determined that steam electric ash ponds and flue gas desulfurization systems are the source of many wastewater pollutants. The EPA is in the process of evaluating the existing effluent limit guidelines (ELGs) for steam electric power plants. In 2010, the EPA issued an information collection request (ICR) to collect data about steam electric power plant water discharges. Ameren Missouri completed and submitted a response to the ICR in September 2010.

In response to challenges by environmental groups, the EPA agreed to a consent decree in November 2010. The consent decree required the EPA to propose revisions to the effluent guideline limitations by July 23, 2012, and finalize the revisions by January 31, 2014. In July 2012 these deadlines were extended to November 20, 2012 for the proposed rulemaking, with final rulemaking by April 28, 2014. The deadline was once again extended in December 2012, and a proposed rule was filed June 7, 2013, with the final rule making scheduled by May 22, 2014. On April 7, 2014, the EPA filed a stipulated extension, establishing September 30, 2015 as the date by which a final action must be signed.

The proposed rule would establish new or additional requirements for wastewater streams from the following processes and byproducts associated with steam electric power generation: flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke. The EPA has identified four "preferred alternatives" for regulating discharges from existing generators, differing in what waste streams are included, generator size and how stringent they are. Each results in a distinct projected level of reductions and associated cost.

States will be required to implement the revisions through regulations and permits. The proposed rule would strengthen the existing controls on discharges from these plants and establish federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The revised effluent guideline limitations are linked to the proposed coal combustion residual (CCR) rule discussed in Section 5.4.2. If ultimately enacted, there is a high possibility that additional wastewater treatment will be required to meet more stringent effluent limitations. The exact scope of the impacts cannot be determined until the final rule is approved.

5.4 Solid Waste Environmental Laws

5.4.1 Current Laws

Resource Conservation and Recovery Act (RCRA - 1976)

RCRA regulates generation, transportation, treatment, storage and disposal of hazardous wastes including solvents, lead, mercury, acids, caustics, and other chemicals; regulates underground storage tanks; and regulates the management of used oil. Currently, RCRA provides guidance on the proper management of solid wastes which includes coal combustion byproducts (i.e. ash disposal).

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA - 1980), Superfund Amendments Reauthorization Act (SARA - 1986)

CERCLA requires release reporting for chemicals that are released into the environment that exceed listed reportable quantities in any twenty-four (24) hour period and required the identification of former sites where hazardous waste had been disposed. The EPA identifies major sites for cleanup actions and places sites with highest risk on the National Priorities List (NPL).

Toxic Substances Control Act (TSCA - 1976)

TSCA established regulations to track 75,000 industrial chemicals in the workplace and requires manufacturers to perform hazard assessments related to their products. Also, TSCA requires specific labeling, inspection, storage, spill cleanup, and disposal requirements for PCBs greater than 50 parts per million (ppm).

Emergency Planning & Community Right-To-Know Act (EPCRA - 1986)

EPCRA was established to help communities protect public health & safety from chemical hazards. EPCRA set up State and Local Emergency Planning and Response Agencies and requires that chemical inventory reports be filed by covered facilities with the local fire department as well as local and state emergency response agencies identifying the locations of hazardous oil and listed chemicals above threshold quantities. EPCRA requires an annual Toxic Release Inventory (TRI) report for each covered facility which exceeds reporting thresholds for various chemical constituents that are released into the environment.

5.4.2 Possible Future Solid Waste Environmental Initiatives

Ash Pond Initiatives

The Tennessee Valley Authority (TVA) ash pond failure in December, 2008, has the potential to change the Company's management of ash and other coal-combustion products because it has refocused Congress and the EPA's attention on ash. In 2000, EPA considered classifying ash as a hazardous waste, but decided to classify it as non-hazardous and intended to prepare guidance for State regulations. The electric industry had been working since that time to provide the EPA with information it wanted without additional regulation through the development of a plan that would include voluntary installation of groundwater monitoring at power plants. On June 21, 2010, spurred in part by TVA's ash pond failure, the EPA proposed rules to regulate coal combustion residuals. The proposal included two regulatory options: (1) regulating CCRs as so-called "special wastes" under the hazardous waste program of RCRA Subtitle C; and (2) regulating CCRs as non-hazardous wastes under Subtitle D of RCRA. Under the Subtitle C option, surface impoundments for the management of CCRs would be allowed to operate for five years and then be required to close within two years after the effective date of the rules. A hazardous waste classification for ash, even temporary, could end most if not all beneficial uses for ash due to the potential user's avoidance of materials that have uncertain regulatory status. The EPA held several public hearings across the country, and the public comment period closed on November 19, 2010. It is anticipated that the EPA will issue the final rule on December 19, 2014.

On February 2, 2014, a break in a storm water pipe beneath an ash basin at the retired Duke Energy Dan River Steam Station in Eden, N.C., caused a release of ash basin water and ash into the Dan River. It is estimated that 30,000 to 39,000 tons of ash was released into the Dan River and coated 70 miles of the river. Duke Energy announced on July 16, 2014, that they had completed cleanup efforts.

Ash Pond Closure Initiatives

Historically, coal ash has typically been wet sluiced into ash ponds. Ash ponds are permitted as wastewater treatment devices under the Missouri water permit program and are subject to closure requirements when they are excluded from the water permit process. Ash pond closures may require an evaluation of groundwater conditions and the development of a closure plan that includes an impervious cap and vegetative cover. Sub-surface water conditions may warrant the installation of a groundwater collection and treatment system and/or the acquisition of additional properties. Long term monitoring of groundwater conditions and the integrity of the cap and vegetation may be required.

Ameren Missouri has begun building landfills to replace ash ponds that are at or near capacity. However, some are only in the early planning stages. As there are no specific regulations regarding the requirements for ash pond closures, costs for closures remain uncertain, though permanent closures could potentially cost tens of millions of dollars at each Energy Center, impose ongoing O&M costs in the hundreds of thousands of dollars per site annually, and result in substantial capital and O&M costs for new wastewater treatment at Energy Centers to treat low volume wastewater that had previously flowed to the ash ponds. If existing ash ponds would be required to be closed prior to reaching capacity, the timing of these costs would be accelerated accordingly.

5.5 Compliance Assumptions[1]

Ameren Missouri has used its assessment of current and future environmental regulations to develop compliance assumptions for use in the analysis of alternative resource plans described in Chapter 9. We have established a "reference case" to

[1] 4 CSR 240-22.040(1); EO-2014-0062 h
Timing and capital costs for environmental compliance options are provided in Appendix B; related O&M costs are provided in the workpapers.

represent the regulatory requirements and compliance measures needed for continued operation of our existing energy centers throughout the 20-year planning horizon. While Ameren Missouri's compliance assumptions are intended to comply with all environmental regulations, there are only a few of these regulations that are driving changes from our current operations that require significant investment. These regulations are outlined in the next section.

5.5.1 Air Environmental Laws

The need for capital investment is anticipated to be driven by MATS, NAAQS and the potential replacement for CSAPR.

Cross State Air Pollution Rule – CSAPR Replacement

Many compliance options are being considered by Ameren Missouri in anticipation of replacement regulations substantially similar to CSAPR that include the following.

- SO_2 emissions
  - Flue Gas Desulfurization
  - Dry Sorbent Injection
  - Burn Ultra-Low Sulfur Coal
  - Purchase SO_2 allowances
  - Unit de-rates or reductions in generation

In general, our current assumption is to meet the SO_2 compliance requirements with the continued burning of Ultra-Low Sulfur Coal at all of our unscrubbed coal Energy Centers in conjunction with the operation of the wet scrubbers at our Sioux Energy Center. Ameren Missouri's existing contracts for Ultra-Low Sulfur Coal will meet our needs through 2017.

While the Company anticipates that this will meet our compliance needs through the near term planning window, Ameren Missouri has identified the risk that this solution may not fully meet our SO_2 compliance needs when the planning window is extended out to the 20 year IRP timeframe. As such, we have assumed the installation of additional FGD to ensure compliance over this timeframe for planning purposes. In establishing our reference case, Ameren Missouri has assumed the installation of such scrubbers at the Labadie and Meramec Energy Centers given the co-benefit available for 1 hour SO_2 compliance at those particular stations. As information, regarding the potential replacement regulations becomes clearer, further analysis will identify the most economical path to meet this requirement including the need for any additional capital investment to meet the regulation.

- NOx emissions

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Low-NO_x burners/OFA
- Purchase NO_x allowances
- Unit de-rates or reductions in generation

The actions assumed by Ameren Missouri to comply with the potential NO_x emissions standards include the installation of additional separated over-fire air ports at Labadie and continued use of low NO_x burners and a staged air combustion process at our other coal fired Energy Centers. Ameren Missouri installed this technology on Labadie Units 2 & 4 in 2012.. In addition to these operational techniques Ameren Missouri has installed SNCR capability at our Sioux Energy Center that can be utilized to further reduce our NO_x as necessary. For our reference case, Ameren Missouri has assumed the addition of Selective Catalytic Reduction (SCR) equipment at our Sioux Energy Center.

As information and interpretations of the replacement regulations become more certain, further analysis will be performed to identify the appropriate compliance, including the identification of additional capital investment required to meet the regulation.

Mercury and Air Toxics Standard - MATS

The compliance options that have been considered to meet MATS include the following.

- Hg emissions
  - Activated Carbon Injection (ACI)
  - Fuel Additives

In order to comply with the Hg emissions standards set by the MATS rule, Ameren Missouri anticipates making investments in ACI systems at the Labadie and Rush Island Energy Centers as well as units 3&4 at Meramec, along with Hg monitoring systems. Plans for mercury control at Sioux include chemical additives combined with the existing wet scrubbers.

- Particulate Matter (PM) emissions;
  - ESP upgrades or replacements
  - Flue Gas Conditioning

Ameren Missouri is making ESP upgrades at Labadie and anticipates (to a much lesser extent) ESP upgrades at the Meramec Energy Center as well to achieve compliance with the PM emission limits associated with the MATS rule. These investments will be in conjunction with PM CEMS equipment at all of our coal-fired Energy Centers.

- Hydrogen Chloride HCl emissions
  - FGD (Dry or Wet Scrubbers)
  - Dry Sorbent Injection (DSI)

Testing of prototype HCl CEMs at Rush Island in late 2013, in partnership with EPRI, has provided additional data substantiating that actual emissions are under the MATS standard when burning the ultra-low sulfur fuels.

5.5.2 Water Environmental Laws

The need for capital investment is anticipated to be driven by the requirements of sections 316(a) and 316(b) of the Clean Water Act in addition to the Steam Electric Effluent Limitations Guidelines Revisions.

Clean Water Act 316(a)

The compliance options that have been considered to meet the CWA 316(a) include the following.

To meet the thermal standard

- Demonstration of non-impact
- Installation of Closed loop Cooling Towers
- Installation of "helper" Cooling Towers

While Ameren Missouri assumes that current Energy Center operations will meet our compliance needs in the near term, Ameren Missouri has identified the risk that this solution may not fully meet our compliance needs when the planning window is extended out to the 20-year IRP planning window. As such, Ameren Missouri has assumed the installation of "helper" Cooling Towers at its Labadie Energy Center to meet probable regulations.

Clean Water Act 316(b)

The compliance options that have been considered to meet the CWA 316(b) include the following.

To meet the impingement and entrainment standards

- Installation of Fine Mesh Screens
- Installation of Cooling Towers

Ameren Missouri anticipates the installation of fine mesh screens, at all coal fired energy centers and the Callaway Energy Center, to achieve compliance with potential 316(b) limits.

As information and interpretations of 316(a) & 316(b) regulations become more certain, further analysis will be performed to identify the appropriate compliance path including the identification of additional capital investment required to meet the regulations.

Effluent Limitations Guidelines Revisions

The current proposed rule would strengthen the existing controls on discharges from Ameren Missouri's Energy Centers and establish federal limits on the levels of toxic metals in wastewater that can be discharged from power plants including mercury, arsenic, selenium, and potentially copper and iron. Ultimate enactment of these guidelines may require the use of sophisticated physical, chemical and/or biological treatment systems. Ameren Missouri has assumed that ash and scrubber solid wastes would likely require dry systems with the use of landfills for disposal. Additionally, the Company has assumed that scrubber wastewater discharges would likely be the most highly regulated discharges and that co-mingling of low volume waste streams (as currently allowed) may be precluded. Compliance will likely be mandated through the NPDES permit process with anticipated compliance over a 5 to 8 year period.

The compliance options that have been considered to meet the Steam Electric Effluent Guidelines include the following.

To meet the proposed standards

- Installation of Waste Water Treatment Systems

The development of the Steam Electric Effluent Limitations Guidelines has driven a long term IRP assumption that Waste Water Treatment Systems would be required at each of our coal-fired Energy Centers. This assumption will be closely monitored and as these regulations become clear, further analysis will identify the most economical path to meet this requirement including the need for any additional capital investment.

5.5.3 Solid Waste Environmental Laws

The need for capital investment is anticipated to be driven by the Coal Combustion Residuals regulation.

Coal Combustion Residuals - CCR

The compliance options that have been considered to meet the CCR include the following.

- To meet the proposed standards

- Possible shut down of existing ash ponds
- Construct new landfills
- New Monitoring
- Less Recycling of coal ash
- Installation of Waste Water Treatment Plants

Our current plans to meet the Coal Combustion Residuals regulation include the development and construction of new landfills at our Labadie, Rush Island and Meramec Energy Centers in addition to the one already constructed at the Sioux Energy Center. The timing of these investments will be based on the final interpretations of the Coal Combustion Residuals regulations. As these regulations become clear, further analysis will identify the most economical path to meet this requirement including the need for any additional capital investment.

5.5.4 Other Environmental Laws

Other Environmental Projects

Other environmental projects include Spill Prevention, Control, and Countermeasure (SPCC) Rule projects and avian protection projects from 2014-2018.

5.5.5 Summary

Ameren Missouri's probable compliance timing and cost assumptions, as illustrated in Appendix B, are based on current, proposed and potential environmental regulations. Given the length of the IRP Planning window, the likelihood of changes in environmental laws and regulations, and the uncertainty surrounding labor and materials costs in the future, these assumptions could change substantially but represent Ameren Missouri's best estimate of these costs at this time. The diamonds in the chart represents the Company's reference case, while the arrows represent potential timing changes under a more aggressive (accelerated) or a more moderate (delayed) implementation of each regulation.

5.6 Compliance References

6. New Supply Side Resources

Highlights

- *Ameren Missouri evaluated over 20 coal and natural gas resource options. Three options were selected as final candidate resource options – Gas Combined Cycle, Gas Simple Cycle Combustion Turbine, and Ultra-super-critical Pulverized Coal. Gas Combined Cycle exhibits the lowest cost on a levelized cost of energy (LCOE) basis among conventional generation resources.*
- *Wind energy resources exhibit the lowest cost on an LCOE basis among all candidate resource options. Ameren Missouri has evaluated options for development of wind resources both within Missouri and across the broader region.*
- *The small modular nuclear reactor technology (SMR) represents the nuclear resource option because of the increased flexibility it can provide in terms of operation, scalability, construction risk, and financing considerations at a comparable cost to conventional large-scale nuclear technologies.*
- *Ameren Missouri intends to install 5.7 MW (DC) of utility-owned solar generation in 2014. The O'Fallon Renewable Energy Center represents the next logical step in the Company's development of solar resources following the installation and evaluation of various solar energy technologies at its General Office Building in St. Louis.*
- *Ameren Missouri is evaluating options for expansion at its existing Keokuk Energy Center as well as options for smaller hydroelectric generation.*

Ameren Missouri engaged Black & Veatch to conduct a supply-side screening analysis of various coal and gas power generation technologies in support of Ameren Missouri's 2011 IRP. This analysis was reviewed by Ameren Missouri subject matter experts and updated as needed for use in the 2014 IRP. Three options were selected as final candidate resource options to represent fossil fuel resource options – Gas Combined Cycle, Gas Simple Cycle Combustion Turbine, and Ultra-super-critical Pulverized Coal. Gas Combined Cycle exhibits the lowest cost on a levelized cost basis among conventional generation resources.

Ameren Missouri evaluated the Westinghouse AP1000 and small modular reactor (SMR) technologies to represent potential new nuclear resource options. SMR was selected as the nuclear resource to be evaluated in the remaining resource planning process to generally represent new nuclear technology.

Ameren Missouri has analyzed various renewable and energy storage options. In 2013, Ameren Missouri contracted with Black and Veatch to identify renewable potential in Missouri. The study considered solar, wind, landfill gas, hydroelectric, anaerobic digestion, and biomass resources. Ameren Missouri identified a universe of storage resource options, including pumped hydro storage, compressed air energy storage (CAES), and a number of battery technologies. Pumped hydroelectric storage was selected as the energy storage resource to be included in our evaluation of alternative resource plans as a major supply-side resource.

Capital costs for all of the preliminary candidate supply-side options included transmission interconnection costs, whether provided by Black and Veatch or Ameren's own transmission planning group.[1] These costs were also subjected to project cost uncertainty as explained in chapter 9.

6.1 New Thermal Resources[2]

6.1.1 Potential Coal and Gas Options

For its 2011 IRP, Ameren Missouri engaged Black & Veatch to conduct a supply-side screening analysis of various power generation technologies in support of Ameren Missouri's IRP. This analysis was reviewed by Ameren Missouri subject matter experts and updated as needed for use in the 2014 IRP.

A multistage approach was used to determine the list of options to be characterized in the analysis. The first stage consisted of the development of a "universe" list of potential gas and coal fueled generation options and a fatal flaw screening. The universe list was screened to develop an "evaluated" list of options by conducting a high-level fatal flaw analysis based on Black & Veatch's engineering experience. The universe list and fatal flaw analysis are included in Chapter 6 – Appendix A. Options that did not pass the high-level fatal flaw analysis consisted of those that could not be reasonably developed or implemented by Ameren Missouri.

After the fatal flaw screening, the second stage consisted of a Preliminary Screening. The purpose of the Preliminary Screening was to provide an initial ranking of the evaluated resource options. The list of options subjected to Preliminary Screening are listed in Table 6.1. Utilizing input from Ameren Missouri subject matter experts, performance, cost and operating estimates were developed for each option included in the Preliminary Screening. A scoring methodology was developed with the intent of

[1] None of the preliminary candidate options were eliminated on the basis of interconnection or other transmission analysis.
4 CSR 240-22.040(4)(B); 4 CSR 240-22.040(4)(C)

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

comparing options within their fuel group (i.e., coal or gas). A weighted score was then developed for each option by analyzing the following categories: utility cost, environmental cost, risk reduction, planning flexibility, and operability. Several criteria were established within each category on the basis of Black & Veatch's experience and considering Ameren Missouri's planning needs. Numerical scores were assigned according to how each option met the criterion. The criteria scores were weighted and summed to obtain a category score. The sum of the category scores resulted in the overall preliminary screening score. The preliminary screening analysis can be found in Chapter 6 – Appendix B. It is important to note that the options with carbon capture did not include any sequestration costs during the screening analysis. Ameren Missouri estimated the sequestration costs per MWh generated using estimates from a National Energy Technology Laboratory report[3]. The report estimated CO_2 transportation cost at \$3.65/ton and storage at \$5.75/ton in 2011 dollars, which equates to a total of \$9.78/ton in 2013 dollars using a 2% escalation rate.

Table 6.1 Preliminary Candidate Options[4]

Fuel Type	Base Load Technologies
Coal	Greenfield - Subcritical CFB
Coal	Greenfield - USCPC
Coal	Greenfield - USCPC w/ Carbon Capture
Coal	Greenfield - IGCC
Coal	Greenfield - Supercritical CFB
Coal	Greenfield - IGCC w/ Carbon Capture
Coal	Greenfield - Sub-CFB w/ Carbon Capture
Coal	Greenfield - USCPC w/ Carbon Capture
Gas	Greenfield - 2-on-1 501F Combined Cycle
Gas	Greenfield - CCCT w/ Carbon Capture
Gas	Greenfield - Molten Carbonate Fuel Cel
	Intermediate Load Technologies
Gas	Greenfield - 2x1 Wartsila 20V34SG
Gas	Greenfield - 7EA (Profile 2)
	Peaking Load Technologies
Gas	Greenfield - Twelve Wartsila Recip. Engines
Gas	Greenfield - Two 501Fs (10% CF)
Gas	Greenfield - Two 501Fs (5% CF)
Gas	Mexico - One LM6000 Sprint (10% CF)
Gas	Mexico - One LM6000 Sprint (5% CF)
Gas	Raccoon Creek - One 7EA (5% CF)
Gas	Raccoon Creek - One 7EA (10% CF)

From the Preliminary Screening scoring, a limited number of evaluated options were selected as part of the third stage of the analysis. Using the Preliminary Screening scoring results as a guide, Ameren Missouri selected several candidate options to consider for Ameren Missouri's resource modeling effort. These options are shown in Table 6.2 and are listed by technology type and fuel source.

[3] http://www.netl.doe.gov/energy-analyses/pubs/QGESS_CO2T&S_Rev2_20130408.pdf, page 20
[4] 4 CSR 240-22.040(2)(C)

Table 6.2 Candidate Coal and Gas Options

Technology Description	Load Type	Fuel Type
Greenfield - USCPC w/ Carbon Capture	Base	Coal
Greenfield - Combined Cycle	Base	Gas
Greenfield - Simple Cycle	Peaking	Gas

Due to U.S. EPA's proposed environmental regulations for carbon dioxide (CO_2) emissions from new power plants, Ameren Missouri has assumed that future coal builds will require carbon capture, thus we can eliminate coal resources without carbon capture from further consideration. It is reasonable to use one coal option to represent coal in the analysis since operating costs and performance for ultra-supercritical pulverized coal (USCPC) and integrated gas combined-cycle (IGCC) are similar. If the coal option performs well then it may be necessary to do more analysis to determine the best coal technology. Based on the screening analysis, it was concluded that USCPC will be analyzed to represent the coal resource type. A Greenfield option was selected to represent the simple cycle resource option, but additional analysis would be needed to determine the best simple cycle CTG resource option if this resource option were to be selected for implementation. Gas Combined Cycle exhibits the lowest cost on a levelized cost of energy (LCOE) basis among conventional generation resources. The potential candidate resource options with selected operating and cost characteristics, including the levelized cost of energy (LCOE), are listed in Table 6.3. The preliminary screening analysis and technology characterization can be found in Chapter 6 – Appendix B.

Table 6.3 Candidate Coal & Gas Resources

Resource Option	Technology Description	Plant Output (MW)	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	Forced Outage Rate (%)	LCOE (¢/kWh)
Greenfield - USCPC w/ Carbon Capture	Coal	679	$5,453	$33.9	$19.9	85%	8%	16.33
Greenfield - Combined Cycle	Gas	600	$1,259	$7.6	$4.0	45%	2%	9.45
Greenfield - Simple Cycle	Gas	352	$766	$7.5	$13.9	5%	5%	29.28

6.1.2 Potential Nuclear Resources[5]

Ameren Missouri screened twelve different nuclear technologies in its 2008 IRP with consultation from Black & Veatch. After the initial screening, U.S. EPR, ABWR and AP1000 technologies were evaluated in more detail, and U.S. EPR was selected as the choice of nuclear technology and characterized in more detail. For the 2011 IRP, Ameren Missouri decided to rely on the results of that study and chose the U.S. EPR to

[5] 4 CSR 240-22.040(1); 4 CSR 240-22.040(4)(A)

represent the new nuclear resource option. For the 2012 and 2013 Annual Updates, small modular nuclear reactor (SMR) technology was selected to represent the nuclear resource. For this IRP, Ameren Missouri selected the AP1000 and Westinghouse SMR to represent potential new nuclear resource options. The nuclear technology characterization can be found in Chapter 6 – Appendix B.

AP1000

The AP1000 is a 1,110 MW unit based on earlier Westinghouse Pressurized Water Reactor (PWR) designs. The design has fewer active components than previous designs, which should significantly reduce maintenance, staging, testing and inspection requirements. The AP1000 is the only Generation III+ reactor to have received Design Certification from the U.S. Nuclear Regulatory Commission (NRC).

Currently, there are eight AP1000 reactors under construction worldwide. In late 2013, Bulgaria and England announced intentions to build AP1000 reactors within a few years. Table 6.4 lists the currently active AP1000 projects and expected in-service date.

Table 6.4 AP1000 Projects Worldwide

Project	Country	Expected In-Service Date
Sanmen 1	China	2014
Sanmen 2	China	By 2016
Haiyang 1	China	By 2016
Haiyang 2	China	By 2016
Summer 2	United States	late 2017/early 2018
Summer 3	United States	2018
Vogtle 3	United States	2018
Vogtle 4	United States	2019

Capital Cost

Ameren Missouri conducted a literature search of overnight capital costs including owners' costs. Table 6.5 lists the more recent capital cost per kW estimates from different sources, which include owner's cost but exclude AFUDC. The near-term (2015) and longer term (2025) cost estimates from Electric Power Research Institute (EPRI) indicate as the nuclear technology matures it is likely that the costs will decrease over time.

Table 6.5 Nuclear Overnight Capital Cost

$2013	EPRI (2015)	EPRI (2025)	Lazard	Vogtle 3&4	Average
$/kW	4,422	4,318	5,661	4,882	4,821

Sources:

- EPRI- Program on Technology Innovation: Integrated Generation Technology Options 2012, February 2013, p. 1-11
- EPRI- Program on Technology Innovation: Integrated Generation Technology Options 2012, February 2013, p. 1-12
- Lazard- Levelized Cost of Energy Analysis- Version 7.0, August 2013, p. 15
- Vogtle Units 3&4 – Eighth Semi-Annual Construction Monitoring Report, February 2013, p.38

Ameren Missouri chose to use Vogtle's capital cost for the nuclear option, which was closest to the average of all cost estimates; therefore bringing the total capital cost of a new 1,100 MW nuclear resource to $5.370 Billion (overnight cost).

Small Modular Reactors

Although the new nuclear plants in the current global nuclear expansion are large scale reactors employing advanced safety features and enhanced reliability, the United States nuclear industry is considering a different approach by turning away from "bigger is better" toward "smaller is better" reactors.

SMRs have a number of characteristics that illustrate the unique role that they can play in our energy mix: (1) SMRs are relatively small in power output, (300 MW or less), versus large-scale reactors that can have a power output of more than 1,000 MW; and (2) SMR designs are modular. Unlike traditional reactors, SMRs would be manufactured and assembled at a factory and shipped to the construction site as nearly complete units, resulting in much lower capital costs and much shorter construction schedules. SMRs also permit greater flexibility through smaller, incremental additions to baseload electrical generation, and more SMRs can be added and linked together for additional output as needed.

SMR designs and concepts can be grouped into three sets based on design type, licensing and deployment schedule, and maturity of design.

- Light water reactor (LWR) based designs » 10-15 years to commercial availability
- Non-LWR designs » 15-25 years to commercial availability
- Advanced Reactor Technologies » 20-30 years to commercial availability

The Westinghouse 225 MWe SMR is an integral pressurized light water reactor based on Westinghouse's 1100 MWe AP1000 design. The Westinghouse design utilizes electric driven pumps to circulate coolant through the core and steam generator. Analysis of the passive safety systems has shown that the reactor can go for seven days without AC power.

Consistent with our commitment to taking proactive steps today to maintain generation options to meet our state's energy needs in the future, Ameren Missouri and Westinghouse Electric Company announced in April 2012 an alliance to apply for Department of Energy (DOE) SMR investment funds of up to $452 million. In November 2012, the grant money was awarded to Babcock & Wilcox Company for the mPower SMR.

The objectives of the DOE program are to support efforts for the United States to become the global leader in the design, engineering, manufacture and sale of American-made SMRs around the world, as well as expand our nation's options for nuclear power. This DOE program presents an opportunity for savings associated with design and operating license development costs. It also comes with a transformational economic development opportunity for the state of Missouri, which includes becoming the hub for the engineering design, development, manufacturing and construction of American-made SMR technology in Missouri, in the United States and around the world. While the initial funding by DOE under this program was awarded to another alliance, program funding remains. In 2013, the DOE offered a second FOA for an award to support a new project to design, certify and help commercialize SMRs. Ameren Missouri and Westinghouse pursued funding under this DOE program. In December 2013, the DOE selected NuScale Power, LLC. Ameren Missouri still considers the development, manufacturing and construction of SMRs to be an important initiative to help create a cleaner energy portfolio for our state and country.

Capital Cost

Ameren Missouri chose to use a cost estimate of $5,000/kW (2013$), representing an expectation that the new technology would be competitive with large scale technologies currently available. Based on this assumption, the total capital cost of a new 225 MW SMR is expected to be $1.125 Billion (overnight cost).

The potential nuclear candidate resource options are listed in Table 6.6. The nuclear LCOE calculations are based on a 40 year economic life.

Table 6.6 Candidate Nuclear Resources

Resource Option	Plant Output (MW)	Total Project Cost Includes Owners Cost, ($/kW)	Annual Decommissioning Costs, ($1,000)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	Forced Outage Rate (%)	LCOE (¢/kWh)
AP1000	1,100	$4,882	$6,481	$141	$2.1	94%	2%	10.36
SMR	225	$5,000	$1,326	$132	$2.1	96%	2%	10.18

SMR was selected as the nuclear resource to be evaluated in the remaining resource planning process as a major supply-side resource. The Company chose to specifically evaluate SMR technology as a resource option because of the increased flexibility it can provide in terms of operation, scalability, construction risk, and financing considerations at a comparable cost. Because the costs and performance of the AP1000 and SMR technologies are similar, the SMR technology can also serve as a proxy for a partial ownership stake in a large nuclear unit such as the AP1000. It is important to ensure that all viable technology options are maintained.[6] Should Ameren Missouri move forward with construction of new nuclear generation resources, the technology selection and specification will have to be revisited in greater detail. It may also be necessary to solicit interest from potential partners prior to moving forward.

6.2 Potential Renewable Resources[7]

In 2013, Ameren Missouri contracted with Black and Veatch to identify renewable potential in Missouri and, more specifically, Ameren Missouri's service territory. The study considered solar, wind, landfill gas, hydroelectric, anaerobic digestion, and biomass resources. Black and Veatch also provided a detailed characterization of the potential projects, which can be found in Chapter 6 – Appendix C.

6.2.1 Potential Landfill Gas Projects

Black & Veatch utilized the Landfill Methane Outreach Program (LMOP) database assembled by the U.S. Environmental Protection Agency (EPA), as well as information available from the Missouri Department of Natural Resources (DNR) regarding LFG production in Missouri. Based on these sources, the sites that have the potential to generate more than 2 MW in the 2014 to 2024 time period within Ameren Missouri's service territory were analyzed further.

Landfill Gas Overview

Landfill gas (LFG) is produced by the decomposition of the organic portion of waste stored in landfills. LFG typically has methane content in the range of 45 to 55 percent and is considered an environmental issue. Methane is a potent greenhouse gas, 25 times more harmful than CO_2. In many landfills, a collection system has been installed, and the LFG is being flared rather than being released into the atmosphere. By adding power generation equipment to the collection system (reciprocating engines, small gas turbines, or other devices), LFG can be used to generate electricity. LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy technologies. There are more than 600 LFG energy recovery systems installed in the United States.

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[6] 4 CSR 240-22.040(2)(C)2

[7] 4 CSR 240-22.040(1); 4 CSR 240-22.040(2); 4 CSR 240-22.040(4)(A)

In June 2012, Ameren Missouri's Maryland Heights Renewable Energy Center (MHREC) began operation. 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. It has a total net summer capacity of 9 MW (net). This facility burns methane gas produced by the IESI Landfill in Maryland Heights, MO, in three Solar 4.9 MW Mercury 50 gas turbines to produce electricity. In August 2012, the MHREC was certified as a qualified renewable energy resource by the DNR.

Applications

LFG can be used to generate electricity and/or provide process heat, or the gas can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. There are several types of commercial power generation technologies that can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. About 75 percent of the landfills that generate electricity use internal combustion engines. Depending on the volume of the gas flow, it may be feasible to generate power via a combustion turbine (e.g., MHREC) or a gas-fired boiler. Fuel cells are another possibility but are in the early stages of commercial development, and were not considered in this analysis.

Resource Availability

Gas production at a landfill is primarily dependent on both the depth and the age of waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, waste depth greater than 40 feet, and at least 25 inches of precipitation annually. The life of an LFG resource is limited. After waste deliveries to a landfill cease and the landfill is capped, LFG production will decline. This decline typically follows a first order decay. Project lifespan for an LFG project is expected to be 20 years.

Candidate Landfill Identification and Characterization

Black & Veatch employed information provided by the LMOP database of landfills to estimate the technical potential for landfill gas power generation in Missouri. The LMOP database provides information on landfill status (i.e., open or closed), closure date, and amount of waste in place. In addition, Black & Veatch reviewed information assembled by the DNR, which provided additional details on candidate landfills within the state. According to DNR's definitions, a landfill must meet the following criteria to be considered a candidate for an LFG project:

- Have more than one million tons of waste in place.
- Be active or have been closed for fewer than 10 years.

or:

- Have an active LFG collection system and flare.
- Have LFG composition of at least 35 percent methane.

Based on review of these sources, 28 landfills were identified as candidates for LFG projects. DNR provided additional information regarding estimated gas production curves (from 2014 through 2024) for each of the candidate landfills. Based on these gas production curves, Black & Veatch estimated the average gas flow and generation capacity. The peak gas flow and generation capacity for these projects during the period from 2014 to 2024 was also estimated. Based on review of the information provided by DNR and internal estimates of generation capacities, Black & Veatch identified six landfills within Ameren Missouri's service territory with potential to provide greater than 2 MW (net) of LFG-fired generation capacity throughout the 2014 to 2024 timeframe:

- IESI Champ (future expansion) (Maryland Heights)
- Missouri Pass (Maryland Heights)
- Maple Hill (Macon)
- Lemons East (Dexter)
- Eagle Ridge (Springfield)
- IESI Timber Ridge (Richwoods)

For each of these landfills, Black & Veatch characterized the quantities of waste landfilled, LFG production curves, design of LFG collection systems, and current uses of the landfill gas. To confirm the design of the LFG collection systems, Black & Veatch requested all publicly available design documentation and information on these six landfills from the Custodian of Records of the Missouri DNR Hazardous Waste & Solid Waste Programs. Upon receipt, these documents were reviewed by a Black & Veatch geotechnical engineer familiar with landfill design and LFG-to-energy projects.

With the exception of IESI Champ, these projects are likely to employ reciprocating engines to generate electricity from LFG. Due to the larger generation capacity of the IESI Champ project and the current configuration of the MHEC Facility (i.e., three CTGs), this project will employ combustion turbine technologies.

Table 6.7 contains details of the six potential landfill gas projects. The levelized fixed charge rate used in the LCOE calculations does not include the ad valorem tax rate since the first year fixed operations & maintenance costs provided by Black & Veatch included property tax. Chapter 6– Appendix C contains more detailed information.

Table 6.7 Potential Landfill Gas Resources

Resource Option	Technology Description	Plant Output (MW)	First Year Fuel Cost, ($/Mbtu)	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	Forced Outage Rate (%)	LCOE (¢/kWh)
IESI Champ (expansion)	CT	3.7	$2.50	$4,390	$111	$11.6	90%	8%	12.53
Maple Hill	RICE	4	$2.50	$4,300	$111	$11.6	90%	8%	12.76
ISESI Timber Ridge	RICE	3	$2.50	$4,680	$120	$10.5	90%	8%	13.28
Lemons East	RICE	3	$2.50	$4,680	$120	$10.5	90%	8%	13.28
Eagle Ridge	RICE	2	$2.50	$5,290	$180	$11.9	90%	8%	15.15
Missouri Pass	RICE	2	$2.50	$5,290	$180	$11.9	90%	8%	15.15

6.2.2 Potential Hydroelectric Projects

Black & Veatch utilized the database of potential hydroelectric projects assembled by the Idaho National Laboratory (INL), supplemented by information from both Black & Veatch and Ameren Missouri. Based on these sources, sites that have the potential to generate between 2 to 50 MW were identified.

Hydroelectric Overview

Traditional hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation and using the water to drive a turbine and generator set. The amount of kinetic energy captured by a turbine is dependent on the head (vertical height the water is falling) and the flow rate of the water. Often, the potential energy of the water is increased by blocking (and storing) its natural flow with a dam.

If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such "run-of-river" or "diversion" applications allow for hydroelectric generation without the impact of damming the waterway.

Resource Availability

A hydroelectric resource can be defined as any flow of water that can be used as a source of potential or kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and generate electricity regardless of the season. Run-of-river projects do not impound the water, but instead divert a part or all of the current through a turbine to generate electricity. At run-of-river projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads. Based on analysis of reported data from Global Energy Decisions, in 2006 the aggregate capacity factor over time for all hydroelectric plants in the United States has ranged from an average high of 47 percent to an average low of 31 percent.

Hydrokinetic resources within the study area consist of several river basins and tributaries, including the Mississippi, Missouri, and Osage rivers. There are several hydrokinetic project developers that have obtained Federal Energy Regulatory Commission (FERC) permits in the study area. There is a demonstration hydrokinetic turbine installed on Mississippi Lock & Dam No. 2, upriver from the study region. A great number of these projects within the Ameren Missouri study area are identified as low power hydroelectric projects and fall below the 2 MW minimum project threshold established for this evaluation.

There are numerous undeveloped hydropower sites, including existing dams, within the study region. Hydropower potential has been previously assessed across the U.S. by the Department of Energy INL for the National Energy Strategy. The INL database served as the primary resource for this high level study of Missouri. Developable renewable hydropower resources are constrained by several factors, including the following:

- Water resources.
- Regulatory definitions that define what types and sizes of hydropower are considered "renewable."
- Environmental constraints.

Black & Veatch considered all of these factors in assessing the hydropower resource for the Ameren Missouri study area, as described in more detail below.

Each state may have a different definition as to which energy sources can be considered "renewable." The designation generally applies to legislation that requires electric generating entities serving the state to use a certain amount of renewable energy in their generation portfolio. The state of Missouri defines "renewable" hydropower in the Renewable Energy Standard (RES). According to the RES, hydropower generators can only be considered renewable energy sources if they meet the criteria "hydropower (not including pumped storage) that does not require a new diversion or impoundment of water and that has a nameplate rating of 10 megawatts or less."

In addition to the above regulatory constraints, there are also environmental constraints that reduce the developable hydro potential for the purposes of this analysis. In assessing potential, Black & Veatch applied the following filters in the Ameren Missouri study area:

- The Project Environmental Suitability Factor (PESF) developed by INL indicates the likelihood of potential site development, based on environmental attribute data. PESF generally have the following three discrete values:
    - 0.1 (low likelihood of development).
    - 0.5 (a combination of attributes have reduced the likelihood of development).
    - 0.9 (environmental concerns have little effect on the likelihood of development).

For the purposes of this study, only projects identified in the INL database with a PESF of 0.9 were considered.

- For new generation, Black & Veatch only included projects that involve adding power generation to an existing dam that has no generation. Construction of any new dams or diversions was not considered. As a result, all undeveloped potential hydropower sites were not included in this analysis.
- Project size was limited to sites between 2 and 30 MW based on the INL database search only.

Candidate Hydroelectric Project Identification and Characterization

There were initially 29 projects identified by the INL hydropower resource assessment. Of these, 25 were omitted because of the constraints listed above or because the existing dam (i.e., Ozark Beach) is owned by a utility other than Ameren Missouri. The remaining four sites were investigated further as part of this study for small hydropower potential. These locations consist of three undeveloped sites with no developed hydropower and one site with hydropower generation where the potential may not be fully developed. Information on these potential sites was found using the INL database, as well as a search of public records on the internet and contacting the reported operators of each of the projects.

Table 6.8 contains details of the potential hydroelectric projects. These projects were evaluated assuming a 60-yr economic life. Chapter 6 – Appendix C contains more detailed information. Because the cost estimates for these resources are screening level estimates and because obtaining necessary licenses from FERC can be complex, a more detailed evaluation of specific projects would be necessary before moving forward with a decision to construct.

Table 6.8 Potential Hydroelectric Resources

Resource Option	Plant Output (MW)	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capacity Factor (%)	Forced Outage Rate (%)	LCOE (¢/kWh)
Mississippi L&D 21	10	$4,980	$0	$5.3	40%	3%	15.56
Clearwater	5.3	$3,980	$0	$5.3	40%	3%	12.59
Pomme De Terre	4.6	$3,760	$0	$5.3	60%	3%	8.18
Keokuk - Option 1	4.5	$5,830	$12.4	$8.2	46%	3%	15.66
Keokuk - Option 3	50	$4,739	$5	$0.5	39%	3%	14.96

FERC Approval of Hydrokinetic Projects

FERC has issued guidance for the testing and licensing of new in-river hydrokinetic facilities using a similar licensing procedure as presented above. Developers have filed with FERC for preliminary permits to reserve rights for building in-river hydrokinetic units at 55 sites on the Mississippi River between St. Louis and New Orleans and at over 20 locations on the Missouri River within Missouri.

The first approval for pilot studies of two 35 kW hydrokinetic units using this technology was issued by FERC at Hastings, Minnesota, which became operational in August 2009. As of 2012, these units are installed and operating. The turbine and facility is being used for testing by Hydro Green LLC to demonstrate and improve their hydrokinetic technology.

Information from the January 2009 Free Flow Power pre-application document for the 14 proposed projects along the Missouri portion of the Mississippi River indicate a plan for 45,060 turbines. Each turbine has an average generation of 10 kW, or a total of 450 MW for the 14 projects. Configuration for each proposed project according to Free Flow Power is the use of 900 to 5,000 turbines in a set of matrices. Each matrix would have a 6 meter by 6 meter footprint.

Evaluations of potential environmental impacts, transportation issues, and other river impacts from operation of hydrokinetic units have not yet been conducted. The timing of review of pilot studies in Minnesota and any project-specific evaluations, scale of any approvals, and realistic potential of any of these hydrokinetic projects going forward with FERC licensing is unknown at this time.

6.2.3 Potential Anaerobic Digestion Projects

Biosolids from the treatment of municipal wastewater and animal manures from agricultural operations have been considered as potential sources of feedstock for anaerobic digestion projects. Black & Veatch contacted the St. Louis Metropolitan Sewer District (MSD) to collect information on their wastewater treatment operations, and estimates were generated from the information collected. In addition, Black & Veatch utilized the Missouri Department of Natural Resources (DNR) database on concentrated animal feeding operations (CAFOs) to develop estimates for the potential of digestion from large-scale agricultural operations. Project parameters were characterized for the projects with the potential to generate more than 1 MW, which is an approximation for utility scale development.

Anaerobic Digestion Overview

Anaerobic digestion (AD) is defined as the decomposition of biological wastes by micro-organisms, usually under wet conditions, in the absence of air (specifically oxygen), to produce a gas comprising mostly methane and carbon dioxide. Anaerobic digesters have been used extensively for municipal and agricultural waste treatment for many years. Traditionally, the primary driver for anaerobic digestion projects has been waste reduction and stabilization rather than energy generation. Increasingly stringent agricultural manure and sewage treatment management regulations and increasing interest in renewable energy generation has led to heightened interest in the potential for AD technologies.

Applications

In June 2011, a report issued jointly by the U.S. EPA and the Combined Heat and Power Partnership estimated that 190 MW of generation is produced through the anaerobic digestion of municipal biosolids at 104 facilities across the U.S. The U.S. EPA AgStar program tracks farm-based digestion projects across the U.S. Based on the most recent report issued in September 2012, there are currently 586,000 MWh of electricity generated from more than 178 farm-based digesters. Another 26 MW of generating capacity is currently in the design and construction phase.

Biogas produced by AD facilities can be used in a variety of ways, including heating/steam generation, combined heat and power (CHP) production, gas pipeline injection, and vehicle fuel usage. Most commonly, biogas generated at digestion facilities is utilized onsite for process heat or CHP applications.

Candidate Anaerobic Digestion Characterization

Table 6.9 contains details of the potential anaerobic digestion projects. The levelized fixed charge rate used in the LCOE calculations does not included the ad valorem tax rate since the first year fixed operations & maintenance costs provided by Black & Veatch included property tax. Chapter 6 – Appendix C contains more detailed information.

Table 6.9 Potential Anaerobic Digestion Resources

Resource Option	Livestock Type	Plant Output (MW)	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	Forced Outage Rate (%)	LCOE (¢/kWh)
Newton County 1	Layers	4.5	$7,810	$970	$0	90%	8%	26.17
Mercer County 1	Swine	3.9	$7,890	$990	$0	90%	8%	26.58
Putnam County 2	Swine	3.2	$8,030	$1,000	$0	90%	8%	26.81
Mercer County 2	Swine	3.1	$8,080	$1,000	$0	90%	8%	26.89
Putman County 1	Swine	2.5	$8,240	$1,010	$0	90%	8%	27.17
Gentry County 1	Swine	2.1	$8,420	$1,030	$0	90%	8%	28.07
Gentry County 2	Swine	2.1	$8,480	$1,030	$0	90%	8%	28.23
Sullivan County 4	Swine	2.1	$8,480	$1,030	$0	90%	8%	28.23
Sullivan County 2	Swine	1.8	$8,620	$1,040	$0	90%	8%	28.52
Lewis County 1	Dairy	1.7	$8,690	$1,050	$0	90%	8%	28.65
Vernon County	Swine	1.7	$8,690	$1,050	$0	90%	8%	28.65
Harrison County	Layers	1.6	$8,780	$1,060	$0	90%	8%	28.88
Sullivan County 3	Swine	1.6	$8,780	$1,060	$0	90%	8%	28.88
Lincoln County 1	Layers	1.4	$9,000	$1,080	$0	90%	8%	29.35
Mercer County 3 (new)	Swine	1.2	$9,290	$1,100	$0	90%	8%	29.97
Mercer County 4 (new)	Swine	1.1	$9,470	$1,110	$0	90%	8%	30.29

6.2.4 Potential Biomass Projects

Unlike other renewable energy technologies, in which the site locations within a given area are well defined, biomass resources are geographically dispersed. Therefore, the optimal locations of biomass-fired generation facilities can rarely be narrowed beyond a general region without consideration of specific resource density and other relevant siting criteria. The task of identifying potential biomass projects was conducted in several phases: a high-level identification of potential biomass sites, a detailed assessment of existing biomass resources, a study of the potential for future biomass resources, and a characterization of identified biomass projects.

Biomass Overview

Biomass is any material of recent biological origin. A common form is wood, although biomass often includes crop residues such as corn stover and energy crops such as switchgrass. Solid biomass power generation options include direct fired biomass and co-fired biomass. Black and Veatch's study focused on biomass combustion rather than biomass gasification for the utilization of solid biomass fuels. First, direct combustion processes are employed for nearly all of the world's biomass power facilities. Second, gasification technologies are typically not yet economically competitive with direct combustion options. Advanced biomass gasification concepts such as Biomass Integrated Gasification Combined Cycle (BIGCC) and plasma arc gasification have some potential advantages when compared to conventional combustion technologies, such as increased efficiency and ability to handle problematic waste materials. However, they have not yet been technically demonstrated at commercial scales and have considerably higher capital costs than biomass combustion technologies.

General Biomass Fuel Characteristics

Compared to coal, biomass fuels are generally less dense, have lower energy content, and are more difficult to handle. With some exceptions, these qualities generally economically disadvantage biomass compared to fossil fuels. Table 6.10 presents the typical advantages and disadvantages of biomass fuels compared to coal.

Table 6.10 Biomass Pros and Cons

Biomass Negatives	Biomass Positives
Lower Heating Value	Lower Sulfur, Heavy Metals, and Other Pollutants
Lower Density	Greenhouse Gas Neutral
More Variability	Potentially Lower & More Stable Cost
More Difficult to Handle	Low Ash Content
Can Be High in Moisture Content	Renewable Energy
More Geographically Dispersed	"Green" Image
Limited Fuel Market	Incentives May Be Available
Higher Chloride Content (which may increase boiler tube corrosion)	

Environmental benefits may help make biomass an economically competitive fuel. Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation option. While carbon dioxide is emitted during biomass combustion, an equal amount of carbon dioxide is absorbed from the atmosphere during the biomass growth phase. Thus, biomass fuels "recycle" atmospheric carbon, minimizing its global warming impact.

Resource Availability

To be economically feasible, direct fired biomass plants are located either at the source of a fuel supply (such as a sawmill), within 50 miles of disperse suppliers, or up to a maximum of 200 miles for a very high quantity, low cost supplier. Wood and wood waste are often the primary biomass fuel resources and are typically concentrated in areas of high forest product industry activity. In rural areas, agricultural production can often yield fuel resources that can be collected and burned in biomass plants. Energy crops such as switchgrass and miscanthus have also been identified as potential biomass sources. In urban areas, biomass is typically composed of wood wastes such as construction debris, pallets, and yard and tree trimmings. Locally grown and collected biomass fuels are relatively labor intensive and can provide employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with transportation and delivery of the fuel.

Co-firing Overview

An economical way to burn biomass is to co-fire it with coal in existing plants. Co-fired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be readily designed to accept a variety of fuels.

Co-firing biomass in a coal plant generally has overall positive environmental effects. Biomass fuel is considered carbon-neutral and typically reduces emissions of sulfur, carbon dioxide, nitrogen oxides, and heavy metals, such as mercury. Furthermore, biomass co-firing directly offsets coal use. On the other hand, co-firing may have a negative impact on plant capacity and boiler performance.

There are several methods of biomass co-firing that could be employed for a project. The most appropriate system is a function of the biomass fuel properties and the coal boiler technology. Provided they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. Simply mixing the fuel into the coal pile may be sufficient.

Cyclone boilers and pulverized coal (PC) boilers require smaller fuel size than stokers and fluidized beds and may necessitate additional processing of the biomass prior to combustion. There are two basic approaches to co-firing in this case. The first is to blend the fuels and feed them together to the coal processing equipment (i.e., crushers or pulverizers). In a cyclone boiler, generally up to 10 to 20 percent of the coal heat input could be replaced with biomass using this method. The smaller fuel particle size of a PC plant limits the fuel replacement to perhaps 3 percent. Higher co-firing percentages (10 percent and greater) in a PC unit can be accomplished by developing a separate biomass processing system at somewhat higher cost.

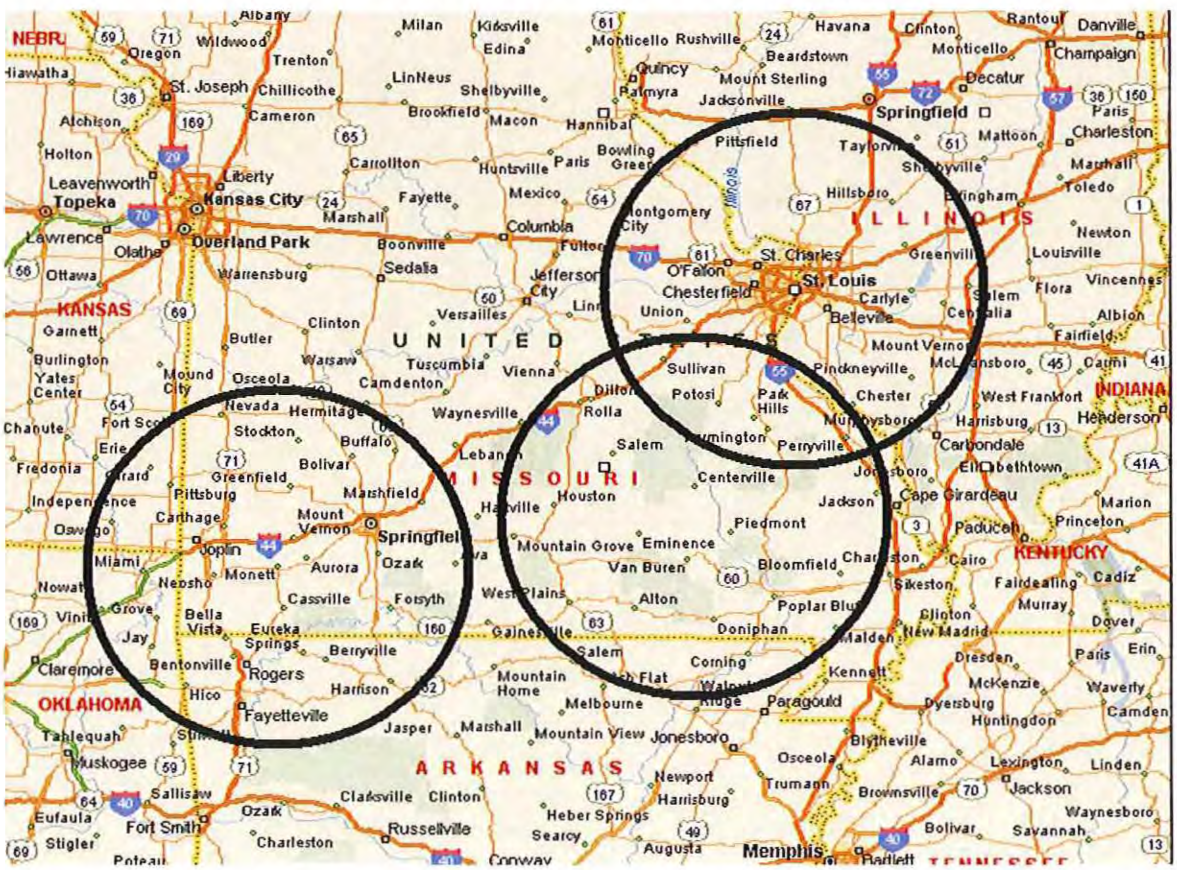
Selected Biomass Inventory Areas

As a first step in evaluating the biomass potential in Missouri, Black & Veatch performed a high-level siting task to identify leading candidate sites for both co-firing and standalone options. Because of the logistics and cost of transportation associated with biomass collection and delivery, biomass facilities rarely obtain fuel from suppliers outside of a 75 mile radius of the facility site. Therefore, Black & Veatch identified three regions of study to be centered on potential facility sites and conducted detailed assessments of existing resources for each of these regions.

In general, the most efficient and least capital intensive utilization of biomass is co-firing in existing solid-fuel generation facilities. Ameren Missouri has four coal-fired generation facilities concentrated relatively near the St. Louis metropolitan area (Labadie, Meramec, Rush Island, and Sioux Plants). Therefore, the St. Louis metropolitan area was the center of one region of study for the detailed biomass assessment.

Following a review of the available data and based on the established criteria, Ellington, Missouri, and Monett, Missouri, were selected as study centers for the detailed biomass assessment. Figure 6.1 shows a map of Missouri with the identified study regions.

Figure 6.1 Selected Biomass Study Regions



6.2.4.1 Assessment of Existing Biomass Resources

For each of the three selected regions, Black & Veatch assessed the biomass resources that are currently commercially available in Missouri. Within the study regions identified, potential suppliers were cataloged. Based on this assessment, the current and projected competing uses were identified, and resource supply curves depicting the cost and quantity of available biomass resources were created.

Assumptions

Black & Veatch used several assumptions to streamline the calculations required to tabulate the inventory data. Biomass has a higher heating value (HHV) of approximately 8,500 Btu/dry pound. This value will fluctuate somewhat, depending on specific materials, but for the most part it is a reasonable proxy at this stage of investigation. The other important fuel properties include moisture content and bulk density. These parameters affect shipping and other potential costs for use as a viable fuel. The assumed values are listed in Table 6.11.

Table 6.11 Biomass Fuel Property Assumptions

Fuel Type	Moisture Content (%)	Higher Heating Value (Btu/dry lb)	Bulk Density (lb/ft3)
Green wood chips	50	8,500	34
Green saw dust	50	8,500	23
Dry wood chips	10	8,500	25
Dry saw dust	10	8,500	17
Bark	50	8,500	34
Poultry litter	30	6,500	n/a

Transportation Cost

Based on hauling data from recent resource assessments, Black & Veatch used a conservative estimate of $4.50 per loaded mile for hauling cost. All charges are based on a 120 yard trailer size, which is capable of hauling 24 ton loads of ground or chipped material.

Supporting assumptions were made to determine the cost of hauling. Typically, the maximum load allowed on highways in the U.S. is approximately 24 tons. It was assumed that appropriately sized trailers could carry a 24 ton load for all of the fuels included in the study.

The transportation costs for each fuel are determined by the following equation:

$$\underset{(\$/\text{MBtu, HHV})}{\textbf{Cost}} = \frac{\underset{(\$/\text{load-mile})}{\textbf{Hauling Cost}} \times \underset{(\text{miles})}{\textbf{Distance}}}{\underset{(\text{MBtu/lb, LHV})}{\textbf{Heating value}} \times \underset{(48{,}000\ \text{lb/load})}{\textbf{Weight of load}}}$$

Biomass Fuel Supply Curves

Fuel supply curves are useful to illustrate the amount of fuel that can be obtained for a particular price in a given area. They can quickly point out "low hanging fruit" and provide direction for fuel procurement efforts. This section presents a fuel supply cost curve for each of the three areas selected. Supply curves for the promising individual fuel resources are provided in Figure 6.2 for the St. Louis region, Figure 6.3 for the Ellington region, and Figure 6.4 for the Monett region.

Figure 6.2 Biomass Fuel Supply Curve for St. Louis Region

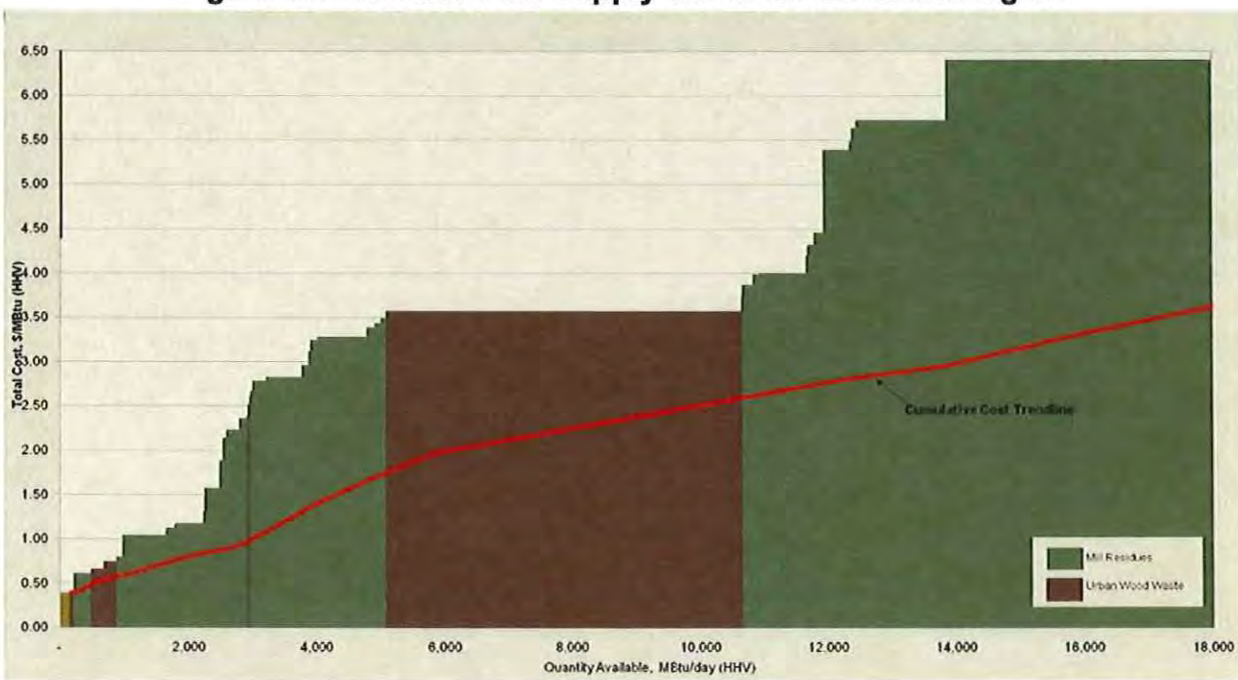


Figure 6.3 Biomass Fuel Supply Curve for Ellington Region

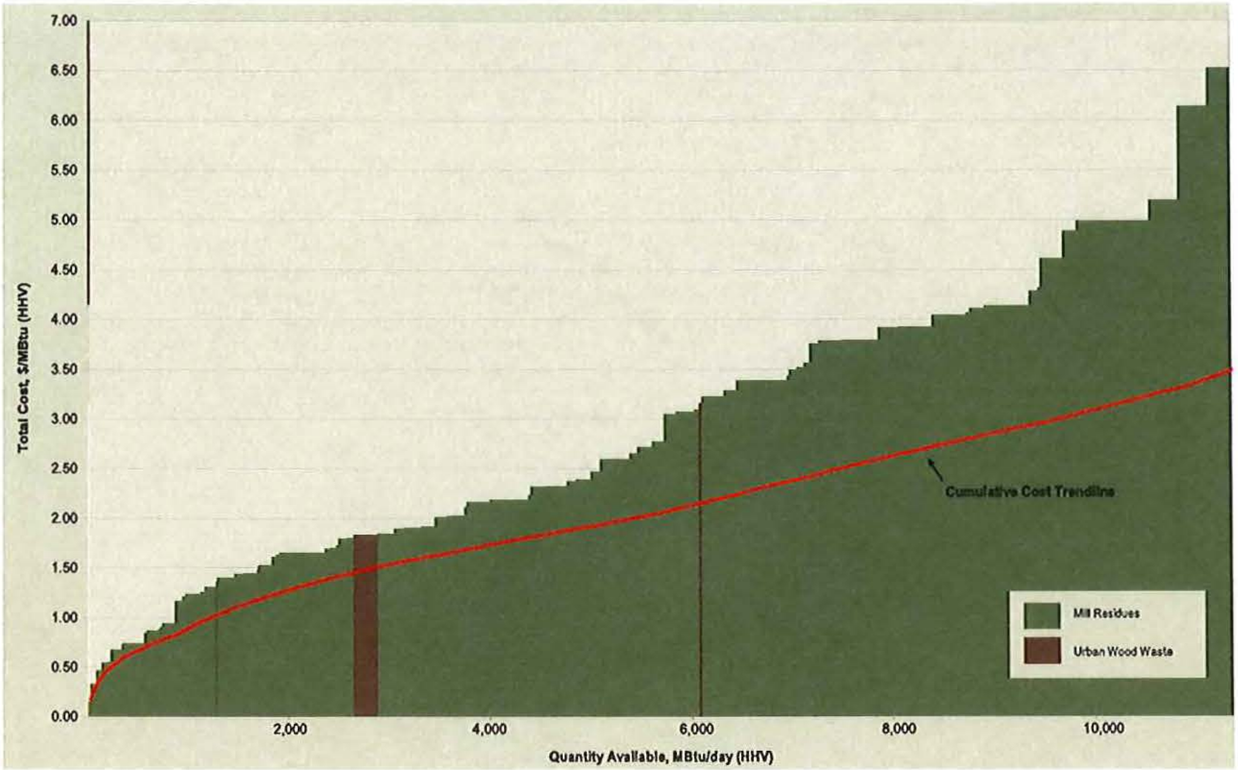
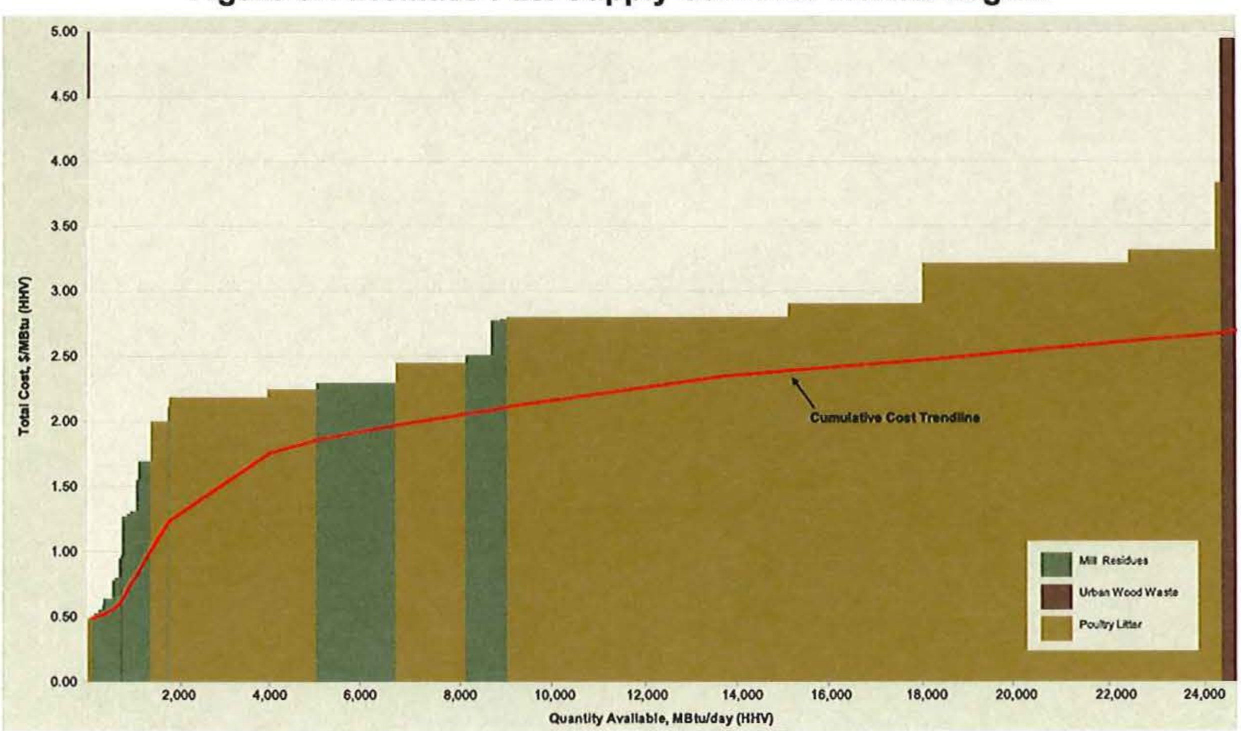


Figure 6.4 Biomass Fuel Supply Curve for Monett Region



Characterization of Identified Biomass Projects

Since biomass residual materials in the defined region have a high degree of utilization, it is not practical to assume that all the discovered resource would be available. Instead, it was assumed that only one third of the resource identified in the detailed assessment would be available for standalone biomass power facilities. The lower capital costs associated with co-firing projects, along with the ability to utilize coal to compensate for short term fuel supply interruptions, allow co-firing projects to be sized to take advantage of available resources. For the co-firing project, Ameren Missouri has identified the Sioux Energy Center as a candidate for biomass co-firing, and expects 5 percent co-firing to be the upper limit (approximately 42 MW).

A 28.8 MW co-firing project at the Sioux Energy Center in St. Louis has been identified which would utilize mill residues and urban wood waste. A 13.5 MW project has been identified in Ellington, the region that would rely primarily on mill residues. Finally a 29.5 MW plant utilizing primarily poultry litter with approximately 20 percent wood residual has been identified for the Monett area. Table 6.12 and Table 6.13 list primary characteristics of the identified projects. More detailed information can be found in Chapter 6 – Appendix C.

Table 6.12 Biomass Resource Fuel Requirements

Project Location	Net Capacity* (MW)	Fuel Supply Identified (MBtu/day)	Available Fuel Supply** (MBtu/day)	Net Plant Heat Rate (Btu/kWh)	Capacity Factor (%)
St. Louis (co-firing)	28.8	18,000	6,000	10,125	85%
Ellington (standalone)	13.5	11,300	3,770	14,500	80%
Monett (standalone)	29.5	24,700	8,230	14,500	80%

* Net Capacity estimated based on available fuel supply, net plant heat rate and capacity factor.

** Available fuel supply estimated as one-third of fuel supply identified.

Table 6.13 Potential Biomass Resources

Project Location	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Fuel Type/Source	First Year Fuel Cost, ($/Mbtu)	Forced Outage Rate (%)	LCOE (¢/kWh)
St. Louis (co-firing)	970	$48	$0	Wood	3.05	8%	5.73
Ellington (standalone)	9,030	$160	$12	Wood	3.16	10%	26.58
Monett (standalone)	6,560	$307	$16	Wood/Litter	2.85	10%	19.38

6.2.5 Potential Solar Resources

Based on a review of available solar technologies and Ameren Missouri's service territory, flat-plate solar photovoltaic (PV) is the most practical technology for implementation.

The solar resource has three primary components: direct, diffuse, and ground reflected. Often the sum of this resource is measured as Global Horizontal Incident (GHI), which is the sum of all irradiance observed by a flat plane over time. Solar PV technologies use GHI. Concentrating solar technologies, including parabolic through, power tower, dish engine, linear Fresnel and concentrating PV (CPV) all us direct component of insolation, called direct normal insolation (DNI).

Global Insolation

Solar PV works by converting sunlight directly into electricity. Unlike solar thermal and concentrating photovoltaics technologies which use DNI, flat plate PV uses global insolation, which is the vector sum of the diffuse and direct components of insolation. A map of the GHI for the U.S. is shown in Figure 6.5. Note that while the desert southwest has the best insolation, there is ample insolation across much of the U.S. for photovoltaic systems. St. Louis has an annual average GHI value of 4.24 kWh/m^2-day. Figure 6.6 shows the monthly average GHI for St. Louis.

Figure 6.5 U.S Global Horizontal Insolation Map

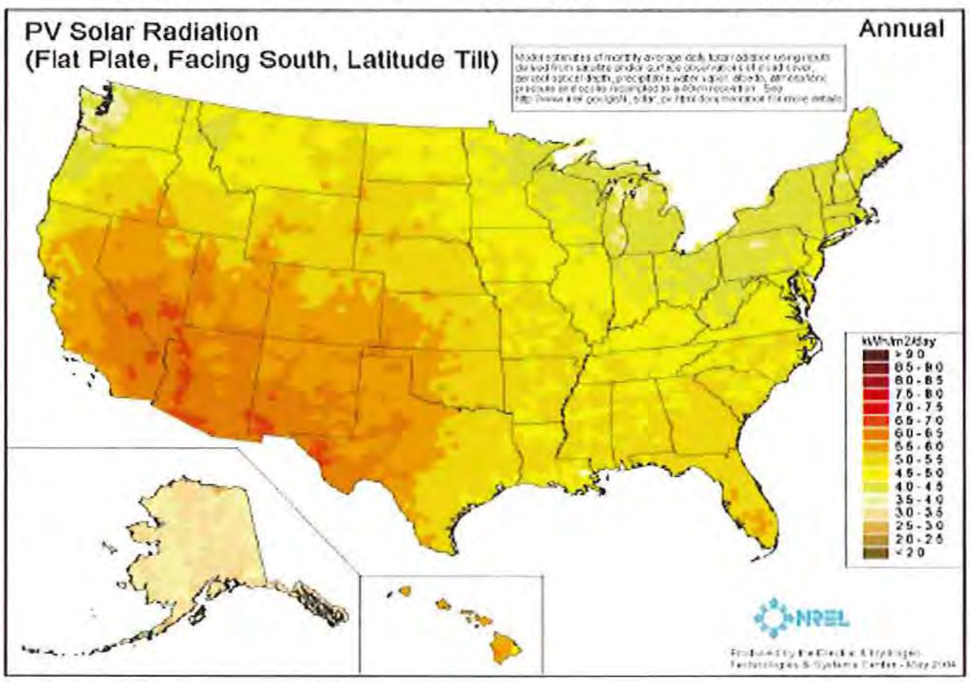
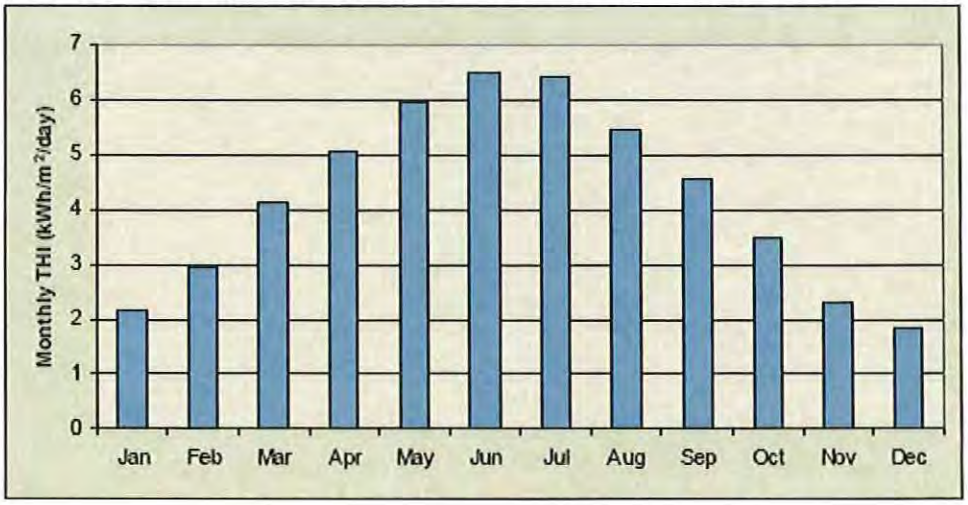


Figure 6.6 Monthly Average Global Horizontal Insolation for St. Louis



Flat Plate Photovoltaics

Traditional wisdom in the solar industry has been that solar PV systems are appropriate for small distributed applications, and that solar thermal systems are more cost effective for large, central station applications. Currently, the world's largest photovoltaic solar generating facility is the Agua Caliente Solar Project being built in Yuma County, Arizona. The Agua Caliente Solar Project is approximately 250 MW [Alternating Current (AC)]. In the U.S., there are over 1,000 operating utility – scale PV installations totaling 2,666 MW AC. Furthermore, central station PV systems are being bid in response to utility requests for proposals.

Ameren Missouri will install 5.7 MW [Direct Current, (DC)] of solar photovoltaic generation next to the Ameren Missouri Belleau substation in St. Charles County. The solar center, O'Fallon Renewable Energy Center (OREC), will feature approximately 19,000 solar panels covering approximately 20 acres on land owned by Ameren Missouri. Construction is anticipated to begin in spring 2014. The installation is scheduled to be in service by 2015 with a total capital cost ranging from $10-$20 million in 2014.

Table 6.14 list primary characteristics of solar. Cost assumptions from were reviewed with internal subject matter experts and revised as appropriate. Chapter 6 – Appendix C contains more detailed information.

Table 6.14 Potential Solar Resource

Resource Option	Plant Output (MW)	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	Forced Outage Rate (%)	LCOE without Incentives (¢/kWh)
Solar	1	$3,777	$25	$0	17.5%	1%	30.51

6.2.5.1 Utility-Scale vs. Customer-Owned Solar

To provide a reference point in our analysis on the economics of Utility vs Customer Owned solar installations a straight-forward comparison is provided to help frame the choices made in our IRP assumptions with regard to meeting RES solar requirements. The framework of this comparison is based on a comparative analysis of the present value of revenue requirements (PVRR). In order to make this comparison for a customer-owned project we assume the entire capital cost is incurred at the beginning of the first year and is not financed by the customer. We assume the customer will receive the same investment tax credit that the utility will receive, and while this changes the capital fixed charge rate for the utility, it simply lowers the expected capital costs in the first year for the customer.

From a cost perspective, we make the assumption that the utility scale project costs will reflect the economies of scale that present themselves to larger projects like those a utility would pursue, which is consistent with assumptions typically found in public sources. Operationally we also assume that a utility will have greater flexibility during installation of solar to maximize the capacity factor that would be available at the installation location. This compares to the assumption provided in PV Watts, which reflects a generic St. Louis region capacity factor that attempts to take into consideration that roof angles and shading will not be optimal on average for a customer-owned installation. Lastly, we assume slightly higher fixed O&M costs for the customer-owned installation since they will typically be contracting this work out on an as needed basis and generally unable to take advantage of the expertise and workforce efficiencies available to a utility owner. Additionally, with regard to fixed O&M, we assume that the size and scale of inverters used in a utility scale project could be rebuilt compared to full replacement for customer-owned solar facilities.

Given this set of assumptions, the analysis demonstrates that the least cost solution for meeting solar requirements is for the utility to own the generation resource, regardless of whether and to what degree tax incentives are available.

Table 6.15 Utility-Scale vs. Customer-Owned Solar Analysis

Assumptions	Utility-Scale	Customer-Owned
Size (kW-DC)	5,745	5,745
(kW-AC)	4,500	4,500
Capacity Factor (%)	15.5%	14.4%
Annual Output Degradation Factor (%)	0.7%	0.7%
Fixed O&M ($/kW-AC)	$25	$29
Economic Life (Years)	20	20
Installed Price ($/W-DC)	$2.96	$4.00
Installed Price ($/W-AC)	$3.78	$5.11
Direct Project Cost	$16,996,500	$22,980,000
RESULTS		
With 30% ITC		
NPV Cost ($)	$15,528,289	$16,792,684
NPV Output (MWh)	86,224	76,067
LCOE with 30% ITC ($/MWh)	$180	$221
With 10% ITC		
NPV Cost ($)	$20,154,189	$21,109,798
NPV Output (MWh)	86,224	76,067
LCOE with 10% ITC ($/MWh)	$234	$278
Without ITC		
NPV Cost ($)	$23,352,222	$26,150,807
NPV Output (MWh)	86,224	76,067
LCOE without ITC ($/MWh)	$271	$344

In addition to the cost advantage, utility-scale solar projects offer benefits that are shared by all customers, rather than just those customers whose premises are favorable to the installation of solar generation and are able to afford the significant up-front costs.

6.2.6 Potential Wind Resources[8]

Black & Veatch performed a high level wind project siting analysis to identify priority multi-county development areas in a study region consisting of the following states: Montana, North Dakota, South Dakota, Kansas, Nebraska, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Michigan, Illinois, Indiana and Kentucky. Analysis was based on a Geographic Information Systems (GIS) siting model developed to estimate the LCOE for wind projects across these states. The GIS model estimates project capital cost and net capacity factor for three representative 100 MW wind project configurations. The three wind project types were identified, as follows:

- Type 1: A moderate to high wind speed, conventional wind project using proven wind turbine technology at the current industry normal 80 meter hub height.

[8] EO-2007-0409 14

- Type 2: A low wind speed project using newer technology built on a well-proven wind turbine platform at the increasingly common 100 meter hub height.
- Type 3: A low to medium wind speed project at a 120 meter hub height, using newer wind turbine technology in the early stages of commercialization.

Based on the LCOE results, Black & Veatch identified a set of 23 promising high-value development areas. Black & Veatch identified potential wind development areas by overlaying maps of wind energy potential with the existing and planned transmission system. Identifying development areas near existing or planned transmission lines minimizes the expected cost of interconnection. A discussion of the transmission system build out that supports expanded renewable energy, and associated cost allocation methods, is included in Chapter 7. At least one high value area was identified in each state, and two or three areas were identified in several states. Each identified area consists of several contiguous counties with low estimated LCOE, significant land available for additional development and no known major environmental barriers. Figure 6.7 shows the entire study area with the lowest calculated LCOE of the three project types. Table 6.16 shows the results for the 80 meter hub height Black & Veatch analysis. Table 6.17 shows the results for the 100 meter hub height Black & Veatch analysis. Table 6.18 shows the results for the 120 meter hub height Black & Veatch analysis.

Figure 6.7 Wind Analysis Identified Development Areas and LCOE

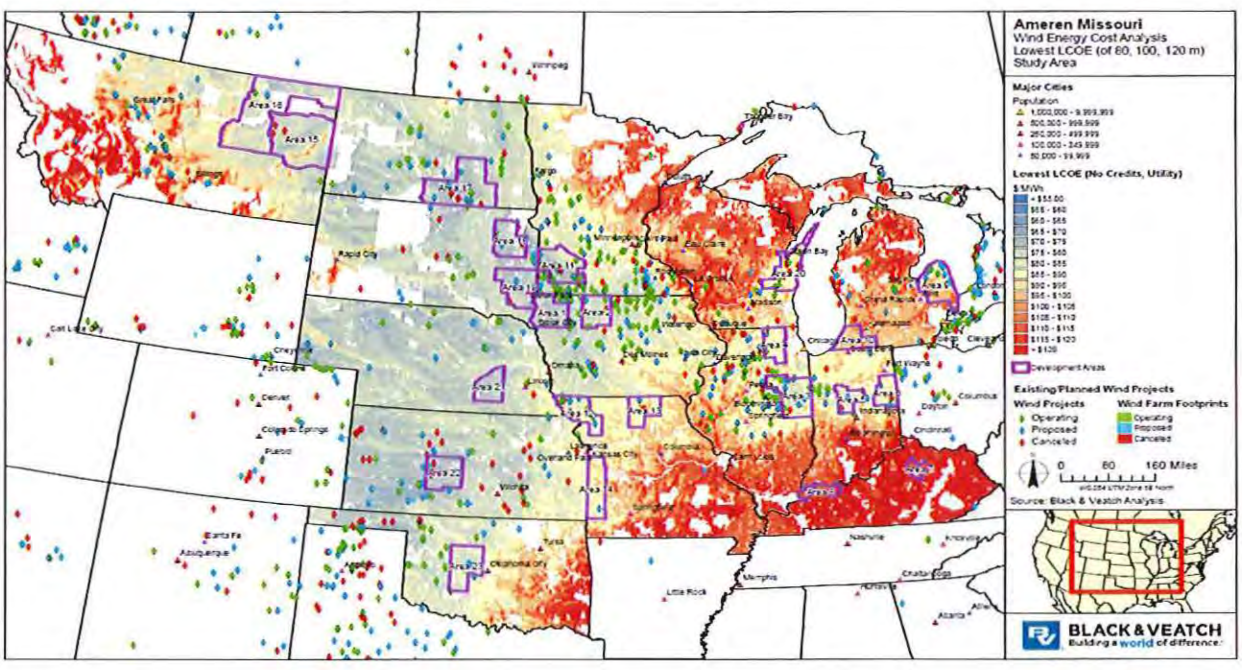


Table 6.16 Priority Development Areas, 80 Meter Results

Area	State	Capital Cost, ($/kW)	Capacity Factor (%)	LCOE without Incentives (¢/kWh)
1	IA	$2,030	40.0%	7.30
2	IA	$2,029	37.9%	7.70
3	IL	$2,025	33.4%	8.80
4	IL	$2,020	31.3%	9.30
5	IN	$2,024	33.3%	8.80
6	IN	$2,021	30.7%	9.50
7	KY	$2,021	21.9%	13.50
8	KY	$2,019	21.7%	13.60
9	MI	$2,020	28.9%	10.20
10	MI	$2,020	27.0%	10.90
11	MN	$2,030	39.3%	7.50
12	MO	$2,022	33.5%	8.70
13	MO	$2,032	30.9%	9.50
14	MO	$2,024	30.4%	9.60
15	MT	$2,039	36.6%	8.10
16	MT	$2,091	37.1%	8.10
17	ND	$2,031	40.0%	7.30
18	SD	$2,031	40.3%	7.30
19	SD	$2,031	39.8%	7.40
20	WI	$2,020	31.3%	9.30
21	NE	$2,021	40.1%	7.30
22	KS	$2,023	40.9%	7.10
23	OK	$2,023	36.2%	8.10

Table 6.17 Priority Development Areas, 100 Meter Results

Area	State	Capital Cost, ($/kW)	Capacity Factor (%)	LCOE without Incentives (¢/kWh)
1	IA	$2,385	41.0%	8.10
2	IA	$2,370	41.1%	8.10
3	IL	$2,370	40.0%	8.30
4	IL	$2,365	37.9%	8.70
5	IN	$2,369	39.8%	8.30
6	IN	$2,366	37.3%	8.90
7	KY	$2,366	28.4%	11.70
8	KY	$2,364	28.3%	11.80
9	MI	$2,365	35.5%	9.40
10	MI	$2,365	33.6%	9.90
11	MN	$2,371	41.0%	8.10
12	MO	$2,368	39.8%	8.30
13	MO	$2,377	37.5%	8.90
14	MO	$2,369	37.0%	9.00
15	MT	$2,381	38.9%	8.60
16	MT	$2,424	39.5%	8.60
17	ND	$2,375	40.9%	8.10
18	SD**	-	-	-
19	SD	$2,373	41.0%	8.10
20	WI	$2,365	37.9%	8.80
21	NE	$2,366	41.0%	8.00
22	KS**	-	-	-
23	OK	$,2367	40.5%	8.20

Note: ** The wind turbines used in the 100 and 120 meter cases are intended for low wind sites. All land in these identified areas is predicted to be above design conditions for these machines.

Table 6.18 Priority Development Areas, 120 Meter Results

Area	State	Capital Cost, ($/kW)	Capacity Factor (%)	LCOE without Incentives (¢/kWh)
1	IA	$2,791	37.6%	10.10
2	IA	$2,772	37.7%	10.00
3	IL	$2,773	36.5%	10.40
4	IL	$2,768	34.5%	10.90
5	IN	$2,772	36.4%	10.40
6	IN	$2,769	34.0%	11.10
7	KY	$2,769	25.2%	15.20
8	KY	$2,767	25.0%	15.20
9	MI	$2,768	32.2%	11.80
10	MI	$2,768	30.3%	12.50
11	MN	$2,773	37.6%	10.00
12	MO	$2,771	36.4%	10.40
13	MO	$2,779	34.1%	11.10
14	MO	$2,772	33.7%	11.20
15	MT	$2,786	35.5%	10.70
16	MT	$2,828	36.1%	10.70
17	ND	$2,778	37.4%	10.10
18	SD**	-	-	-
19	SD	$2,777	37.6%	10.10
20	WI	$2,767	34.5%	10.90
21	NE	$2,769	37.5%	10.00
22	KS**	-	-	-
23	OK	$2,770	37.0%	10.20

Note: ** The wind turbines used in the 100 and 120 meter cases are intended for low wind sites. All land in these identified areas is predicted to be above design conditions for these machines.

Based on the Black & Veatch analysis, cost assumptions were developed for Missouri Wind and Regional Wind for compliance with the Missouri RES. Missouri Wind cost and performance characteristics assumptions are based on the average 100 meter results for Priority Development Areas 12 and 13 located in Missouri. Regional Wind cost and performance characteristics are based on the average 80 meter results for Iowa, Illinois, Minnesota, and South Dakota (i.e., Priority Development Areas 1, 2, 3, 11, 18, and 19) and were selected based on deliverability to MISO, expected cost performance, and relative geographic proximity. Approximately 500 MW of Missouri Wind is assumed to be available for RES Compliance and additional wind for RES compliance or for other resource needs could be supplied by Regional Wind.

Cost assumptions were reviewed with internal subject matter experts and revised as appropriate. Table 6.19 list primary characteristics for potential wind resources. Chapter 6 – Appendix C contains more detailed information.

Table 6.19 Potential Wind Resources

Resource Option	Plant Output (MW)	Total Project Cost Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	LCOE without Incentives (¢/kWh)
Missouri Wind 100 meter Hub Height	100	$2,197	$29	$0	38.7%	8.75
Regional Wind 80 meter Hub Height	101	$1,879	$29	$0	38.5%	7.67

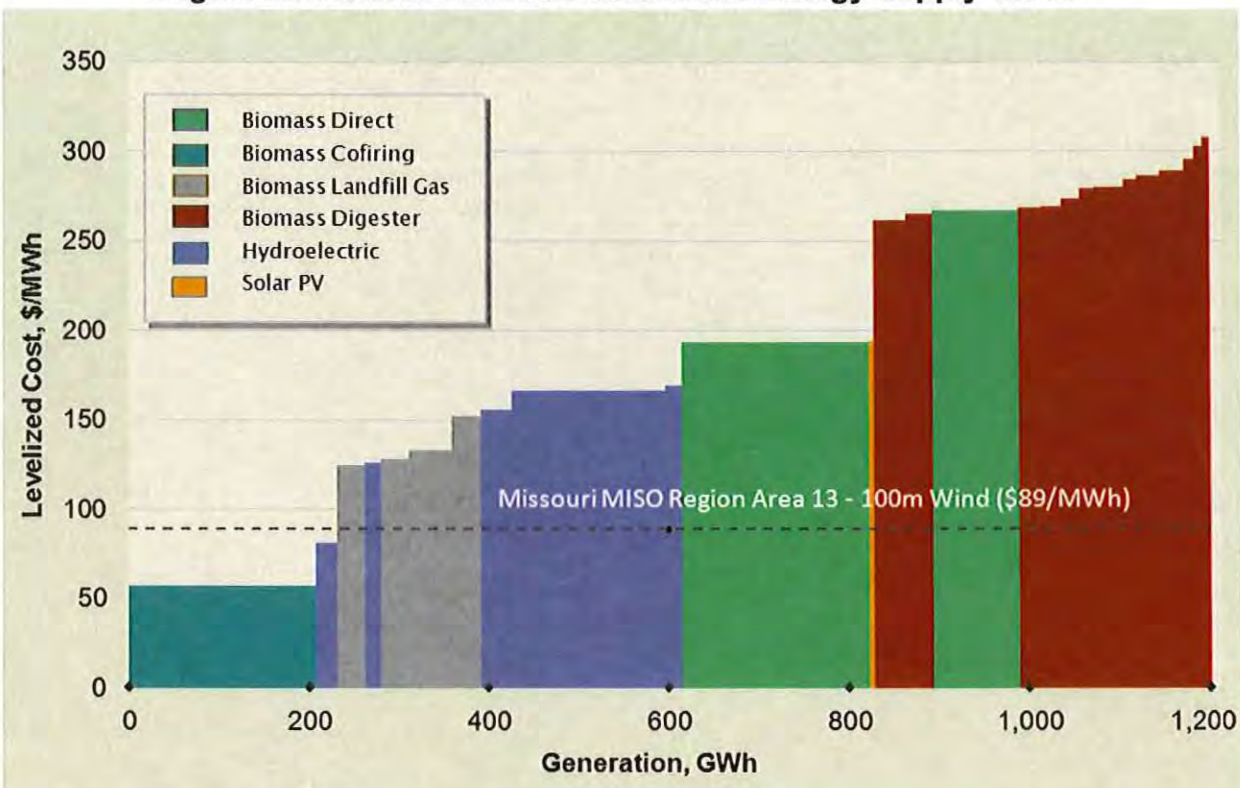
6.2.7 Renewable Supply

Black & Veatch developed a supply curve for the aggregate mix of renewable energy projects considered in the Ameren Missouri service territory. Supply curves are used in economic analyses to determine the quantity of a product that is available for a particular price (e.g., the amount of renewable energy that can be generated within a utility system for under $150/MWh).

The supply curve in Figure 6.8 was constructed by plotting the amount of generation added by each project against its corresponding levelized cost. For this study, the renewable generation added by each project class is plotted against its levelized cost of electricity in ascending order. In this case, generation (GWh/yr) is on the x-axis and levelized cost ($/MWh) is shown on the y-axis. Every "step" on the graph represents an individual project color-coded by its technology type. The curve compares the quantities and costs for the renewable resources and shows which products can be brought to market at the lowest cost (resources toward the left side). Note: the LCOE of wind in the Missouri MISO region (development area 13), with no incentives included, is indicated by a dashed line on the supply curve. Because potential available wind energy is much greater than that from other resources, it has not been incorporated into the supply curve. By comparing the cost of other resources to the cost of wind resources, we can get an idea of their relative competitiveness as a renewable energy resource. With so much potential, it was assumed that enough wind would be available to meet Ameren Missouri's renewable energy requirements.

Biomass co-firing appears to be a cost-effective renewable resource compared to other renewable resources in Figure 6.8. However, the potential for co-firing is much smaller when considering the fuel supply constraints. Although the region is flush with biomass materials, their use as feedstock for power plant operations is highly dependent on the emergence of sustainable fuel supply. It is important to note that biomass co-firing is a fuel substitute and therefore adds no additional energy or capacity benefits. Incorporating the expected energy and capacity benefits would indicate wind, hydroelectric, and landfill gas are more cost-effective resources than biomass co-firing to meet renewable requirements. At this time, Ameren Missouri is not actively considering biomass co-firing as a potential new supply side resource.

Figure 6.8 Ameren Missouri Renewable Energy Supply Curve



6.3 Potential Storage Resources[9]

Ameren Missouri identified a universe of storage resource options, including pumped hydro storage, compressed air energy storage (CAES), and a number of battery technologies. A high-level fatal flaw analysis was conducted as part of the first stage of the supply-side selection analysis for storage resources. Options that did not pass the high-level fatal flaw analysis consist of those that could not be reasonably developed or implemented by Ameren Missouri. The universe of storage options and fatal flaw analysis are included in Chapter 6 – Appendix D. Three options passed the initial screen: pumped hydroelectric energy storage, compressed air energy storage, and sodium-sulfur (NaS) battery energy storage.

Pumped Hydroelectric Energy Storage

Pumped hydroelectric energy storage is a large-scale, mature, commercial utility-scale technology used at many locations in the United States and worldwide. Conventional

[9] 4 CSR 240-22.040(1); 4 CSR 240-22.040(2); 4 CSR 240-22.040(4)(A)

pumped hydroelectric energy storage uses two water reservoirs, separated vertically. During off peak hours water is pumped from the lower reservoir to the upper reservoir. During intermediate and peak-demand periods the water is released from the upper reservoir to generate electricity. Church Mountain, located about midway between Taum Sauk State Park and Johnson Shut-ins State Park, was identified as the potential site for a new 600 MW pumped hydro plant. For this IRP, Ameren Missouri has updated the capital costs based on recent construction experience at its Taum Sauk facility.

Compressed Air Energy Storage

CAES is the only commercial utility-scale energy storage technology available today, other than pumped hydroelectric energy storage. There are two commercial operating CAES facilities in the world---one in Alabama and one in Germany. A CAES facility consists of an energy production and energy storage system. The energy production facilities operate using off-peak electricity available at night and on weekends to compress air into the storage vessel. During intermediate and peak-demand periods, compressed air is released from the pressurized energy storage system, heated by combustion of natural gas, and used to drive high efficiency turbines to produce electricity. Using electric powered compressors, air is injected through dedicated wells and used to charge the storage vessel. According to the U.S. Department of Energy (DOE)/EPRI 2013 Electricity Storage Handbook in Collaboration with National Rural Electric Cooperative Association (NRECA)---(Sandia National Laboratories, July 2013), future designs may include a natural gas fired combustion turbine (CT) which is used to generate heat during the expansion process for second-generation CAES plants.

Compressed Air Storage System

Compressed air for a CAES plant may be stored in aboveground pipes or vessels (e.g., high-pressure pipes or tanks), man-made excavations in salt or rock formations or in naturally occurring porous rock aquifers and gas reservoirs. Site selection depends upon suitable geological characteristics that include:

- Location of a suitable formation at a depth of 1,000 to 3,000 feet.
- Formation tightness (absence of significant air leakage).
- Stability under daily pressure changes.

Performance and cost estimates were based on the 441 MW CT-CAES (below ground) technology provided in the DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA (Sandia National Laboratories, July 2013). The storage capacity was based on 8 hrs. While CAES technology has been in use for decades, it's very limited deployment (only one CAES plant in the U.S.) prevents it from being considered a mature technology like pumped hydro storage.

Sodium-Sulfur Battery Energy Storage

Sodium-sulfur (NaS) batteries are a commercial energy storage technology finding applications in electric utility distribution grid support and power integration with renewables resources. NaS battery technology has potential use in grid support due to its long discharge period (approximately 6 hours). NaS batteries can be installed at power generating facilities, substations, and renewable energy generation facilities where they are charged during off peak hours and discharged when needed. The battery modules contain arrays of NaS cells, a heating element, and dry sand. The NaS batteries are constructed of airtight, double-walled stainless-steel enclosures as a safety feature due to the module materials (i.e., hazardous material including metallic sodium).

NaS batteries are only available in multiples of 1 MW units with installations typically ranging in size from 2 to 10 MW. Currently, NaS battery storage systems have been installed at 221 sites worldwide totaling 316 MW. According to the DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA (Sandia National Laboratories, July 2013), the largest single NaS battery energy storage installation is the 34 MW wind-stabilization project in Japan.

Performance and cost estimates were based on the 50 MW NaS bulk storage system provided in the DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA (Sandia National Laboratories, July 2013). The estimated life of a NaS battery is approximately 15 years based on 4,500 cycles at rated discharge.
Table 6.20 shows the energy storage technologies that were evaluated. Chapter 6 – Appendix D contains more information.

Table 6.20 Potential Energy Storage Resources

Resource Option	Operations Mode	Plant Output, MW	Total Project Cost-Includes Owners Cost, ($/kW)	First Year Fixed O&M Cost ($/kW)	First Year Variable O&M Cost ($/MWh)	Heat Rate HHV, Btu/kWh	Annual Capacity Factor, Percentage	LCOE (¢/kWh)
Pumped Hydroelectric Storage	Peaking	600	$1,739	$3.4	$3.4	n/a	22%	16.00
Compressed Air Energy Storage (CAES) with Combustion Tubrine	Peaking	441	$687	$3.1	$3.1	4,170	30%	10.41
Sodium Sulfur (NaS) Battery (Bulk Storage)	Peaking	50	$3,259	$4.8	$0.5	n/a	25%	23.63

Pumped hydroelectric storage was selected as the energy storage resource to be evaluated in the remaining resource planning process as a major supply-side resource. Pumped hydroelectric energy storage is a large-scale, mature, commercial utility-scale technology used at many locations in the United States and worldwide compared to CAES, with only two commercial operating facilities in the world. In addition, a potential pumped storage site owned by Ameren Missouri exists at Church Mountain.

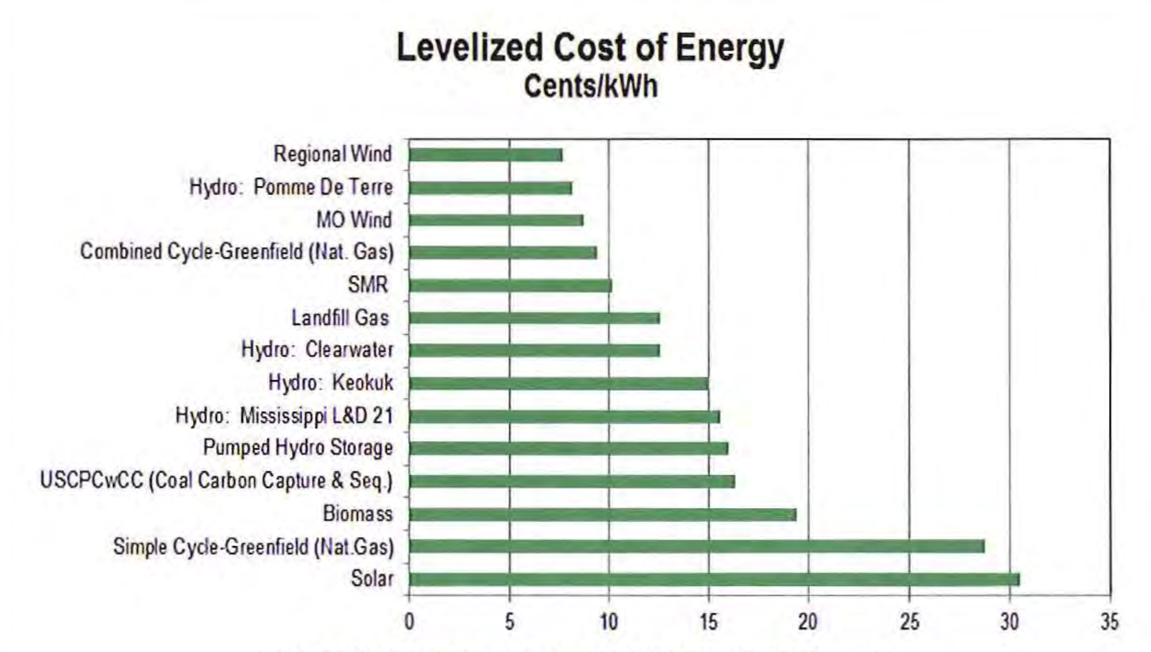
6.4 Power Purchase Agreements

After discussions with Ameren Missouri's Asset Management and Trading organization it was determined that there were no pending potential long-term power purchases for consideration at the time of the analysis. Furthermore, Ameren Missouri learned from its experience in developing the 2008 and 2011 IRPs that soliciting the market for long-term power purchases or sales is not productive for bidders given the data at this stage of the analysis is generic, and potential respondents are reluctant to share information on potential agreements without a high expectation for an executed contract. Evaluation of generic power purchase agreements would not be expected to yield different results in terms of relative performance of resource types, as the only reasonable assumption that could be made absent specific information would be that such an agreement would be cost-based.

6.5 Final Candidate Resource Options[10]

Figure 6.9 shows the LCOE without incentives (e.g., Investment Tax Credits or Production Tax Credits) for a range of potential supply side resources.

Figure 6.9 Levelized Cost of Energy



Note: Solar does not include Investment Tax Credits or Production Tax Credits.

It is important to note that levelized cost of energy figures, while useful for convenient comparisons of resource alternatives, do not fully capture all of the relative strengths

[10] 4 CSR 240-22.040(4); 4 CSR 240-22.040(4)(C)

and challenges of each resource type. For example, wind resources are intermittent resources and therefore cannot be counted on for meeting peak demand requirements in the same way a nuclear or gas-fired resource can. Similarly, using an energy cost measure to evaluate peaking resources such as simple cycle CTGs does not fully reflect their value as a capacity resource. The levelized cost of wind resources presented in Figure 6.9 also does not reflect the full cost of transmission infrastructure needed to integrate wind and other intermittent resources into the electric grid. Such costs are allocated to members of the MISO based on methods approved by the FERC. Based on the screening analysis, it was concluded that USCPC was selected to represent the coal resource type. However, USCPC was not considered further in the alternative resource plans because of its cost and the uncertainty of CCS technology.[11] Table 6.21 shows the component analysis for the levelized cost of energy figures.

Table 6.21 Levelized Cost of Energy Component Analysis[12]

Resource	Levelized Cost of Energy (¢/kWh)									
	Capital	Fixed O&M	Variable O&M	Fuel	Pump Cost	Decommission	CO2	SO2	NOx	Total Cost
New Resources										
Regional Wind	6.66	1.00	0.00	--	--	--	--	--	--	**7.67**
Hydro: Pomme De Terre	7.44	0.00	0.74	--	--	--	--	--	--	**8.18**
MO Wind	7.75	1.00	0.00	--	--	--	--	--	--	**8.75**
Combined Cycle	3.87	0.24	0.49	4.71	--	--	0.15	0.00	0.00	**9.45**
Nuclear: SMR	6.63	2.03	0.28	1.18	--	0.07	--	--	--	**10.18**
Landfill Gas	5.89	1.64	1.35	3.64	--	--	--	0.00	0.00	**12.53**
Hydro: Clearwater	11.85	0.00	0.74	--	--	--	--	--	--	**12.59**
Hydro: Keokuk Option 3	14.69	0.20	0.07	--	--	--	--	--	--	**14.96**
Hydro: Mississippi L&D 21	14.82	0.00	0.74	--	--	--	--	--	--	**15.56**
Storage: Pumped Storage	9.50	0.23	0.51	--	5.76	--	--	--	--	**16.00**
Coal (USCPC w CCS)	8.93	0.59	2.57	4.18	--	--	0.06	0.00	0.00	**16.33**
Biomass	10.39	2.66	1.40	4.92	--	--	--	0.00	0.00	**19.38**
Simple Cycle	19.94	2.11	1.72	5.34	--	--	0.17	0.00	0.00	**29.28**
Solar	28.61	1.90	0.00	--	--	--	--	--	--	**30.51**

The LCOE for future resource options is an important measure for assessing these options. However, it is not the only factor that must be considered in making resource decisions. Facts and conditions surrounding future environmental regulations, commodity market prices, economic conditions, economic development opportunities, and other factors must be considered as well. A robust range of uncertainty exists for many of these factors, all of which leads to one overriding conclusion – maintaining effective options to pursue alternative resource options in a timely fashion is a prudent course of action.

[11] 4 CSR 240-22.040(2)(C)2
[12] 4 CSR 240-22.040(2)(C)1

6.6 Compliance References

7. Transmission and Distribution

Highlights

- *Ameren Missouri will construct eight of the eleven transmission projects that have been approved by the Midcontinent Independent System Operator (MISO) Board of Directors in Missouri for completion before 2019.*
- *Ameren Missouri has initiated a Voltage Control Pilot Project to evaluate operational effectiveness and evaluate Conservation Voltage Reduction as an energy and demand conservation measure.*
- *New high-efficiency distribution line transformers may provide cost-effective energy savings beyond new efficiency standards.*
- *Ameren Missouri views the Smart Grid as more of a direction than a destination; this is evidenced by our continuous infusion of technology into the electric grid over the past 30 years – with plenty of work yet to be done.*

Ameren Missouri is continuously maintaining or replacing aging infrastructure in order to provide safe and reliable service. Rapid growth during the 1960s and 70s due to a housing boom and the advent of air conditioning resulted in a replacement of the previous vintage infrastructure and an even larger new system. As growth has slowed over time the infrastructure has not experienced appropriate turnover. This lack of asset turnover means our existing grid is heavily populated with 40-60 year old equipment that is at risk of failure, obsolete, and inefficient compared to modern equipment. Ameren Missouri has proactively begun to address this issue, and plans to make significant investments to replace its aging grid infrastructure to improve overall system reliability and efficiency. In doing so, Ameren Missouri will incorporate cost-effective advanced technologies on an opportunistic basis that provide enhanced energy services and mitigate future obsolescence.

Ameren Missouri has evaluated a range of transmission and distribution options as part of an End-to-End Efficiency Study performed with the assistance of Electric Power Research Institute (EPRI). The study helped identify some promising opportunities including Conservation Voltage Reduction, Reactive Power Optimization, and High-Efficiency Transformers. Many of the conclusions from the EPRI study were based on generic data and therefore need further analysis. In fact, Ameren Missouri has initiated a Voltage Control Pilot Project to evaluate operational effectiveness and evaluate Conservation Voltage Reduction as a demand and energy conservation measure.

A total of 11 transmission projects have been approved by the MISO Board of Directors for construction in Missouri for completion before 2019. Ameren Missouri will construct eight of these projects. The projects will address future reliability issues and provide for continued safe and reliable service to customers.

7.1 Transmission

7.1.1 Existing System[1]

Ameren Missouri owns and operates a 2,956 mile transmission system that operates at voltages from 345 kV to 138 kV. The system is composed of the following equipment:

- 1,295 miles of 138 kV transmission circuits
- 718 miles of 161 kV transmission circuits
- 943 miles of 345 kV transmission circuits
- 21 extra high voltage substations with a maximum voltage of 345 kV
- 44 substations with a maximum voltage of 161 kV
- 63 substations with a maximum voltage of 138 kV

7.1.2 Regional Transmission Organization Planning[2]

Ameren Missouri contracts with Ameren Services to provide transmission services including operations, planning, engineering, construction, and administrative services.

Since 2004, Ameren Missouri has been a member of the Midcontinent Independent System Operator (prior to April 26, 2013 it was called the Midwest Independent Transmission System Operator), or MISO, a Regional Transmission Organization (RTO). MISO was approved as the nation's first RTO in 2001 and is an independent nonprofit organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba.

A key responsibility of the MISO is the development of the annual MISO Transmission Expansion Plan (MTEP). Ameren Missouri is an active participant in the MISO MTEP development process. Participation in the MISO MTEP process is the method by which Ameren Missouri's transmission plan is incorporated into the annual MTEP document. The overall planning process can be described as a combination of "Bottom–Up" projects identified in the individual MISO Transmission Owners transmission plans which address issues more local in nature and are driven by the need to safely and reliably provide service to customers, and projects identified during MISO's "Top-Down" studies, which address issues more regional in nature and provide economic benefits or address public policy mandates or goals.[3]

[1] 4 CSR 240-22.045(1)
[2] 4 CSR 240-22.045(3)
[3] 4 CSR 240-22.045(3)(B)1

Through these MTEP related activities, Ameren Missouri works with MISO, adjacent MISO Transmission Owners and stakeholders to promote a robust and beneficial transmission system throughout the Midwest region. Ameren Missouri's participation helps ensure that opportunities for system expansion that would provide benefits to Ameren Missouri customers are thoroughly examined. This combination of Bottom-Up and Top-Down planning helps insure all issues are addressed in an effective and efficient manner.[4]

Guidance is provided to MISO on the assumptions, inputs, and system models that are used to perform the various analyses of the overall MISO transmission system. Ameren Missouri's participation in the MTEP development process includes: review of MISO and stakeholder developed material, comments and feedback, and working to insure the projects approved in the MTEP are in the interests of the Ameren Missouri customers. Ameren Missouri is regularly represented by attendance and participation in the MISO stakeholder organizations which are key components of the MTEP development process including the:

- Planning Advisory Committee (PAC) – The PAC provides input to the MISO planning staff related to the process, adequacy, integrity and fairness of the MISO wide transmission expansion plan.
- Planning Subcommittee (PSC) – The PSC provides advice, guidance, and recommendations to MISO staff with the goal of enabling MISO to efficiently and timely execute its planning responsibilities, as set forth in the MISO Tariff, MISO/Transmission Owner Agreement, FERC Orders applicable to planning and other applicable documents.
- Interconnection Process Task Force (IPTF) – The IPTF has the goal of reducing study time and increasing certainty associated with new requests to connect to the transmission grid within MISO
- Subregional Planning Meetings (SPM) – The SPMs are hosted by MISO in accordance with FERC Order 890, to encourage an open and transparent planning process. Stakeholders are encouraged to participate in discussions of planning issues and proposals on a more local basis and discuss projects, issues and concepts that are potentially driving the need for new transmission expansions.
- Loss Of Load Expectation Working Group (LOLEWG) – The LOLEWG works with MISO staff to perform Loss of Load Expectation (LOLE) analysis that calculates the congestion free Planning Reserve Margin (PRM) requirements as defined in the Module E-1 of the Tariff.

[4] 4 CSR 240-22.045(3)(B)2; 4 CSR 240-22.045(3)(B)3; 4 CSR 240-22.045(3)(B)4

- Regional Expansion Criteria and Benefits Task Force (RECBTF) – The RECBTF is a forum for stakeholders to provide input in the various processes used in the MISO tariff to allocate the cost of transmission system upgrades and improvements to the appropriate beneficiaries.
- Other Committees, Task Forces and Working Groups as appropriate.

The result of the MTEP process is a compilation of transmission projects that are needed to address system reliability requirements, improve market efficiency, and/or provide specific system benefits as delineated in the MISO Tariff. The MTEP identifies solutions to meet regional transmission needs and to create value opportunities through the implementation of a comprehensive planning approach.

Each MTEP document is identified by the year in which it was completed. Appendix A of each MTEP lists and briefly describes the transmission projects that have been evaluated, determined to be needed and subsequently approved by the MISO Board of Directors (BOD). The MTEP13 document is the culmination of more than 18 months of collaboration between MISO planning staff, MISO Transmission Owners, and stakeholders. Each MTEP cycle focuses upon identifying system issues and improvement opportunities, developing alternatives for consideration, evaluating those options to determine the most effective solutions and finally identifying the preferred solution. As described in more detail in the MISO Tariff, the primary purposes of the MTEP process are to identify transmission projects that:

- Ensure the transmission system supports the customer's needs in a continued safe and reliable manner.
- Provide economic benefits such as increased market efficiency and resultant overall lower energy cost.
- Facilitate public policy objectives such as integrating renewable energy resources.
- Address other issues or goals identified through the stakeholder process.

The interconnection of new generation resources to the transmission system under MISO's control is also an important part of the overall transmission planning effort. Ameren Missouri actively participates in regional generation interconnection studies for proposed generation interconnections inside and outside of the Ameren Missouri area. Participation in these transmission studies ensures that they are performed on a consistent basis and that the proposed connections and any system upgrades needed on the Ameren Missouri transmission system are properly integrated and scheduled to maintain system reliability.

With the approval of MTEP13, a total of 11 transmission projects have been approved by the MISO Board of Directors for construction in Missouri before 2019. A summary of the projects is shown in the table below. Table 7.1 also includes the proportion of transmission service charges arising from the projects that Ameren MO Load is expected to pay.[5] The costs of these projects are not impacted by whether the project is constructed by Ameren Missouri or an affiliate.

Table 7.1 MTEP Transmission Projects in Missouri - Summary

Transmission Projects with a Portion in Missouri in MTEP13 or Prior MTEPs in Service in Late 2013 or Not Yet in Service			
Project Type	**Number of Projects**	**Estimated Total Project Cost ($Million)**	**Estimated Percentage of Transmission Service Charges Arising From the Projects to be Paid by Ameren Missouri Load**
Baseline Reliability or Reliability/Other Projects Not Cost Shared	7	46.3	100%
Baseline Reliability Projects - Cost Shared	1	30.8	86.90%
MVPs 7, 8, & 9	3	784.9	Approximately 8.9%

A brief description of the 11 transmission projects can be found in Appendix A.

A key component of fulfilling Ameren Missouri's obligation of continuing to provide safe and reliable service is the identification of potential future needed transmission upgrades. A list of projects that are under consideration by Ameren and MISO and that are located totally or partially in Missouri is provided in Appendix A in Table 7A.2.[6]

Current and previous transmission system expansion plans can be found on MISO's website: https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx[7]

[5] 4 CSR 240-22.045(3)(A)4
[6] 4 CSR 240-22.045(6)
[7] 4 CSR 240-22.045(3)(C)

Revenue Credits from Previously Constructed Regional Transmission Upgrades[8]

Regional transmission upgrades, such as Multi-Value Projects and Market Efficiency Projects, are eligible for cost sharing under Attachment GG or MM of the MISO Tariff. Ameren Missouri does not have any such projects which receive revenue credits through this process.

7.1.3 Ameren Missouri Transmission Planning[9]

Ameren Missouri's transmission strategy is centered upon meeting the evolving needs of its customers for safe and reliable energy. Each year the Ameren Missouri transmission system is thoroughly examined and studied to verify it will continue to provide Missouri customers with reliable and safe service through compliance with all applicable North American Electric Reliability Corporation (NERC) standards as well as Ameren's Transmission Planning Criteria and Guidelines.

The studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to evaluate all practical alternatives to determine what, where and when system upgrades are required to address the future reliability concern. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, the adequacy of the supply to new and existing substations to meet local load, the expected power flows on the bulk electric system (BES) and the resulting impacts on the reliability of the Ameren Missouri transmission system.

In order to successfully achieve the goal of a safe and reliable transmission system, Ameren Missouri participates in a multitude of transmission planning activities including:

- MISO Transmission Expansion Plan (MTEP) development
- MISO regional generation interconnection studies
- NERC reliability standards development,
- Participation in SERC regional planning and assessment activities,
- Participation in the Eastern Interconnection Planning Collaborative (EIPC)

This high level of involvement affords the opportunity to supply comments and provide input to these many transmission planning processes which supports the goal of

[8] 4 CSR 240-22.045(3)(A)5

[9] 4 CSR 240-22.045(3)(B)1; 4 CSR 240-22.045(3)(B)2; 4 CSR 240-22.045(3)(B)3; 4 CSR 240-22.045(3)(B)4; 4 CSR 240-22.045(4)(A)

maintaining a reliable and safe transmission system which will meet the current and future needs of our Missouri customers.

As part of the Ameren Missouri Transmission Planning Process the ability of transmission system improvements to reduce transmission system losses is considered. A major aspect of Ameren Missouri's focus of providing continued safe and reliable service to our customers is maintaining transmission equipment and replacing aging infrastructure when it approaches the end of its operational life. The Ameren Missouri area experienced rapid economic growth and substantial investment in transmission infrastructure during the 1960s and 70s. Considerable portions of the transmission system are now over forty years old and are reaching the end of their operational life with a commensurate increased risk of failure and higher maintenance expense. The existing equipment is also less efficient than comparable modern equipment. Ameren Missouri is working to address the most critical issues by making targeted investments to replace its aging grid infrastructure to maintain system reliability.

7.1.4 Avoided Transmission Cost Calculation Methodology[10]

The methodology that was used during the development of the previous Integrated Resource Plan was again used in the 2014 Plan. Avoided transmission costs are based upon integrated system effects and are difficult to quantify, as opposed to energy and capacity costs where there are markets that provide specific prices. As part of integration modeling, Ameren Missouri estimated the MW impacts of DSM programs and a corresponding reduction in transmission capital expenditures.

The first step is to identify the transmission projects that are related to serving customer load and their associated cost. An estimated generic marginal cost of system transmission capacity is then calculated and adjusted by applying the following factors:

- Usage Growth-Related Factor - This factor captures the effect that some of the transmission projects cannot be deferred by DSM because they are not driven by usage growth but rather by load relocating to different areas with Ameren Missouri. This causes a local load increase but not a net system load increase.
- Location-specific Factor/Deferrable Factor - This factor accounts for the fact that Ameren analyzes the transmission system in aggregate and it is not possible to determine with certainty which load increase will be deferred by DSM programs. DSM programs are not being designed to avoid or offset specific transmission projects; therefore it is not possible to identify the specific transmission projects which would be deferred.

[10] 4 CSR 240-22.045(2); 4 CSR 240-22.045(3)(A)3

- Condition/Reliability Replacement Factor - This factor approximates the effect that projects constructed to serve increased load will result in turnover of transmission assets. If Ameren Missouri does not upgrade or replace transmission equipment because of DSM, then Ameren Missouri will be required to spend additional funds on maintenance or reliability projects that would have been avoided if the older equipment had been replaced with new equipment as part of the project that was deferred. For example, choosing 70% for this factor says that for every $1 saved from DSM, $0.30 is needed to support the equipment that would have been replaced with new equipment.

The results of the analysis are provided in Appendix A.

7.1.5 Transmission Impacts of Potential Ameren Missouri Generation Resource Additions/Retirements & Power Purchases/Sales[11]

As part of the determination of the proper combination of resources needed to serve the Ameren Missouri load, the size and location of potential future generation resources are estimated. Transmission's role in this process is to assess the transmission system enhancements necessary to safely and reliably deliver the energy from these potential future resources. Table 7.2 provides a high level assessment of interconnection costs for the listed potential future generation resources. These estimates may be impacted by other new resources connecting to the grid, revisions to resource timing, new transmission projects and other factors.

Table 7.2 Transmission Project Costs for New Generation[12] **NP**

[redacted] **

[11] 4 CSR 240-22.045(1)(B); 4 CSR 240-22.045(1)(C); 4 CSR 240-22.040(3); 4 CSR 240-22.040(3)(A)

[12] A list of the transmission upgrades needed to physically interconnect the new resources, their associated costs and amount that would be allocated to Ameren Missouri are provided in workpapers. 4 CSR 240-22.045(3)(D)1; 4 CSR 240-22.045(3)(D)5; 4 CSR 240-22.045(3)(D)6

As part of the determination of the proper combination of resources needed to serve the Ameren Missouri load, the need for continued operation of existing resources is examined. Transmission's role in this process is to determine the overall impact of retiring existing generation resources on the transmission system and identify any system upgrades necessary to maintain safe and reliable service after the resource is no longer available. Table 7.3 contains the results of a high level assessment of the cost of transmission system upgrades needed to provide continued safe and reliable service if the indicated Ameren Missouri generators retire within the planning period. The impact of retiring each generating station was determined separately. If multiple generating stations retired within the planning period the cost of needed transmission upgrades would potentially be greater. These estimates may be impacted by new resources connecting to the grid, revision of the shutdown timeframe, new transmission projects and other factors.

Table 7.3 Estimated Transmission Project Costs for Retirements[13] **NP**

[redacted] **

The Ameren Missouri transmission system was also examined to determine if additional transmission system upgrades would be justified to facilitate power purchases and sales by Ameren Missouri. The analysis indicates an Ameren Missouri import or export capability of 1200 MW, which exceeds the 300 MW import or export minimum requirements. For IRP analysis purposes, Ameren Missouri has used a limit of 300 MW as the maximum allowed shortfall of resources to load and reserve requirements. Because resources would be added to prevent a shortfall greater than 300 MW this represents the minimum import capability requirement to ensure reliable operation of the system. The transmission system analysis indicates no additional transmission system upgrades are justified based upon this requirement.[14]

[13] EO-2014-0062 i
[14] 4 CSR 240-22.040(3)(B)

Transmission Impacts due to New Generation Resource Connections within the MISO Footprint or Point-to-Point Transfers of Energy within the MISO Footprint to Ameren Missouri

Ameren Missouri participates in regional generation interconnection studies for proposed generation interconnections inside the MISO footprint. Participation in these activities ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the Ameren Missouri system to maintain system reliability. Power flow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, additional studies are performed to refine the limitations and develop alternative solutions.

New Generation Resources - Future generation resources within the MISO footprint seeking to connect to the transmission system will be subject to the interconnection requirements described in the MISO Tariff and applicable MISO Business Practice Manuals. In order to interconnect to the transmission system, the resource owner must provide project details including location, resource size, type of service requested, when it wants to connect, etc. After this information has been received, the impacted Transmission Owner and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably interconnect the generation resource to the transmission system.

Point to Point Transactions - The MISO Tariff and applicable MISO Business Practice Manuals describe the process by which transmission service requests can be made to have firm point-to-point transmission service within the MISO footprint. The entity requesting service would provide details including: source and delivery locations, quantity of energy to be transmitted, timing and duration of delivery, etc. After this information has been received, the impacted Transmission Owner(s) and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably support the requested transmission service. The transmission upgrades needed to support a transmission service request will not be determined until the completion of the system study and analysis. The MISO Tariff and MISO Business Practice Manuals that are in effect at the time when the point-to-point transmission service request is submitted will describe the process by which Financial Transmission Rights (FTRs) are allocated and can be obtained by entities.

The total cost of any necessary transmission upgrades cannot be determined until a resource interconnection request and/or a transmission service request has been submitted to MISO via the process described in the MISO Tariff and applicable Business Practice Manuals and the necessary transmission system studies have been performed. The result of the studies will identify the transmission system upgrades necessary to safely and reliably fulfill the transmission service request or generation interconnection request. The studies will include a description of the needed transmission system reinforcements, their location, in service date and estimated total cost. Therefore the cost of any needed system upgrades will not be known until the system study and analysis is complete.

Transmission Impacts due to New Generation Resources outside the MISO Footprint Connecting to the MISO Transmission System or Point-to-Point Transfers of Energy from Outside the MISO Footprint to Ameren Missouri

Ameren Missouri participates in generation interconnection studies for proposed generation interconnections from generators located outside of the MISO footprint. Participation in these activities ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the Ameren Missouri system to maintain system reliability. Power flow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, additional studies are performed to refine the limitations and develop alternative solutions.

New Generation Resources - Future generation resources external to the MISO footprint seeking to connect to the transmission system within the MISO footprint will be subject to the interconnection requirements described in the MISO Tariff and applicable MISO Business Practice Manuals. In order to interconnect to the transmission system, the resource owner must provide project details including location, resource size, type of service requested, when it wants to connect, etc. After this information has been received, the impacted Transmission Owner and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably interconnect the generation resource to the transmission system. The transmission upgrades needed to physically interconnect a generator source within the RTO footprint will not be determined until the completion of the system study and analysis.

Point to Point Transactions - The MISO Tariff and applicable MISO Business Practice Manuals describe the process by which transmission service requests can be made to have firm point-to-point transmission service into the MISO footprint from a generation resource located outside the MISO footprint. The entity requesting service would provide details including: source and delivery locations, quantity of energy to be transmitted, timing and duration of delivery, etc. After this information has been received, the impacted TO(s) and MISO will perform the system study and analysis necessary to determine the transmission upgrades needed to safely and reliably support the requested transmission service. The transmission upgrades needed to support a transmission service request will not be determined until the completion of the system study and analysis. The MISO Tariff and MISO Business Practice Manuals that are in effect at the time when the point-to-point transmission service request is submitted will describe the process by which Financial Transmission Rights (FTRs) are allocated and can be obtained by entities.

The total cost of any necessary transmission upgrades cannot be determined until a resource interconnection request and/or a transmission service request has been submitted to MISO via the process described in the MISO Tariff and applicable Business Practice Manuals and the necessary transmission system studies have been performed. The results of the studies will identify the transmission system upgrades necessary to safely and reliably fulfill the transmission service request or generation interconnection request. The studies will include a description of the needed transmission system reinforcements, their location, in service date and estimated total cost. Therefore the cost of any needed system upgrades will not be known until the system study and analysis is complete.

7.1.6 Cost Allocation Assumptions for Modeling[15]

The MISO Tariff allocates 100% of the BRP revenue requirements to the local zone where the project is located. The MVP revenue requirements are collected under MISO Tariff Schedule 26-A, which is charged to Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules (excluding Exports and Through schedules from MISO to PJM). In addition to MISO estimated charges based on MVP projects approved through January 2014, Ameren Missouri assumed there would be $1Billion per year MVP build-out between 2018 and 2022. Ameren Missouri also assumed approximately 8.9% of the MVP costs to be assigned to its customers.

7.1.7 Advanced Transmission System Technologies[16]

Ameren Missouri views the concept of Smart Grid as an ongoing process rather than a final condition. There has been a steady growth in the development of new advanced transmission system technologies that surpass the capabilities of currently installed equipment. Ameren Missouri's vision is to use advanced technologies as tools in the ongoing pursuit of service reliability, operating efficiency, asset optimization, and a secure energy delivery infrastructure. Ameren Missouri's current focus on advanced transmission system technologies is driven by the benefits associated with these technologies.

[15] 4 CSR 240-22.045(3)(A)4

[16] 4 CSR 240-22.045(3)(A)2; 4 CSR 240-22.045(3)(B); 4 CSR 240-22.045(1)(D); 4 CSR 240-22.045(4)(A) 4 CSR 240-22.045(4)(C); 4 CSR 240-22.045(4)(D); 4 CSR 240-22.045(4)(E)1; 4 CSR 240-22.070(1)(B)

Advanced technologies are examined and considered for implementation in association with the MISO and as part of the MTEP development process and as part of the Ameren Missouri transmission planning and operating activities. Three of the major advanced transmission technologies that have been implemented are briefly described below:

- Synchrophasor (Phasor Measurement Unit - PMU) technology deployment
  Ameren Missouri has been participating in a project with MISO under a DOE grant to increase the number of PMU installations in the Ameren Missouri system. Under the DOE grants, Ameren Missouri has installed these high speed time-synchronized monitoring devices at Labadie, Meramec, and Sioux Power Plants, and Montgomery, Kelso, Loose Creek, and Overton transmission substations. These devices capture high-resolution voltage, current, and frequency data and send the information to a central data gathering facility that is maintained by MISO. Combined PMU measurements will provide a precise, comprehensive view of the entire interconnection and enable advanced monitoring and analysis to identify changes in grid conditions, including the amount and nature of stress on the system. PMU data will feed applications that allow grid operators to understand real-time grid conditions; see early evidence of changing conditions and emerging grid problems; and better diagnose, implement and evaluate remedial actions to protect system reliability. This information is also vital for the development and eventual implementation of predictive software systems to identify potential areas of system weakness before an incident actually occurs.

- Installation of Fiber Optic Ground Wires (OPGW) on all new or rebuilt transmission circuits.
  As part of selected new transmission line projects or rebuilding of an existing transmission line when cost justified, Ameren Missouri is installing OPGW in place of standard steel or aluminum ground wire. OPGW combines the functions of providing a protective ground and a high speed communications path. A typical OPGW cable consists of a tubular structure with one or more optical fibers in it which is then surrounded by layers of steel or aluminum wire. The OPGW cable is installed between the tops of transmission line structures where the steel or aluminum wire connects the adjacent towers to earth ground and shields the transmission line conductors from lightning strikes. The optical fiber communications path has several advantages over traditional metal wire technology including immunity from outside electrical interference (caused by power transmission lines or lightning) and cross-talk from communications on parallel circuits. These advantages make OPGW an ideal choice for Ameren Missouri to use to provide a high-speed data communications path for modern

digital protective relay systems. Ameren Missouri also specifies additional optical fibers be included within the cable for future use by new advanced technologies.

- Purchase and installation of high efficiency EHV transformers[17]
  Ameren Missouri routinely specifies EHV transformers with a higher efficiency than the transformers most commonly purchased by other utilities throughout the US. Ameren Missouri's transformer specifications require the purchase of EHV transformers with very high no-load loss efficiency.

In a study conducted in collaboration with EPRI, Ameren Missouri identified eight types of transmission efficiency or loss reduction measures which are listed in Table 7.4.

Table 7.4 Potential Transmission Efficiency or Loss Reduction Measures[18]

Transmission Efficiency Option	Pass Screen?	Rationale for Exclusion
Reconductoring / Bundling Phase Conductor	Pass	
Shield Wire Segmentation	Pass	
Voltage Upgrade of AC Lines	No	Ameren Missouri has 138 kV and 345 kV lines, but not intermediate 230 kV lines Voltage upgrade would require major system changes
Coordinated Voltage Control	No	Ameren Missouri provides constant voltage schedule to power plants Schedules are intended to maximize both MW output and transient stability margins Not much room for further improvement
Energy-Efficient Transformer	No	Ameren Missouri transformers are large (530 MVA – 760 MVA) Transformers are replaced if diagnostics suggest pending failure or upon failure Specification for new transformers consider capacity and energy losses Ameren Missouri currently uses high-efficiency transformers
Power Flow Control	No	Already considered in conjunction with recent transmission capacity additions. The reliability benefits derived from additional parallel transmission were superior to regulating power flows
Insulation Losses	No	Impact on losses is minimal Insulator maintenance performed for reliability
Conversion from AC to DC	No	Established in principle as a loss-reduction technique but never implemented in a commercial application EPRI demonstration project

[17] 4 CSR 240-22.045(1)(A)
[18] 4 CSR 240-22.045(1)(A)

As shown above, two of these measures passed the qualitative screening: Reconductoring / Bundling Phase Conductor, and Shield Wire Segmentation.

Reconductoring / Bundling Phase Conductor

The thermal capacity of a transmission line can be increased significantly by either: (a) using a larger cross sectional conductor; (b) using an advanced conductor with lower resistance; or (c) by bundling the existing conductor with another of the same characteristics.

If the power flowing over the upgraded line remains the same as for the original conductor then transmission losses can be reduced. The same current magnitude will flow through a lower resistance conductor. Conversely, if the upgraded line is loaded to its updated maximum capacity transmission losses will not be reduced. Reconductoring costs can be reduced through the use of advanced conductors with lower resistance for the same diameter, since that minimizes structural modifications. Restricting reconductoring options to conductors of the same diameter limits the range of line resistance reduction to 20% to 25%. Two different types of same diameter conductors can be applied:

- ACSR/TW: Conventional ACSR conductors with trapezoidal aluminum strands
- HTLS conductors: ACSS, ACSS/TW, ACCR, ACCR/TW, ACCC/TW, others

Depending on how current flow is applied, HTLS conductors can serve various objectives, including: increasing capacity, improving reliability, or reducing line losses. If the primary objective of reconductoring is to reduce losses, then the natural choice for replacement conductor is trapezoidal wire conductor (ACSR/TW), which yields almost the same amount of loss reduction (for the same current) as the HTLS counterparts at much lower price. As the need for transmission expansion is identified through Planning studies and screenings, the use of these specialty conductors can be one of the options considered for analysis, and ultimately selection if determined to be efficacious.

Shield Wire Segmentation

Shield wires are generally steel cables that are coupled to phase conductors to protect AC transmission lines from lightning strikes. Shield wires have relatively high resistance compared to conventional phase conductors such as ACSR (Aluminum Conductor Steel Reinforced). On selected projects Ameren Missouri is installing OPGW in place of standard steel or aluminum ground wire. OPGW combines the functions of providing a protective ground and a high speed communications path. A typical OPGW cable consists of a tubular structure with one or more optical fibers in it which is then surrounded by layers of steel or aluminum wire. A common problem with all ground wires is that power loss occurs in shield wires of AC transmission lines through mutual coupling from the phase conductors of the transmission line. In addition, any induced currents in the shield wires can circulate through the towers to ground, with losses accumulating in the tower footing resistance and ground.

Shield wire losses can be reduced by breaking the conductive path in shield wires, or by reducing the mutual coupling with the phase conductors. Breaking the conductive path in shield wires is known as shield wire segmentation. The shield wires are also insulated from the tower to avoid loop paths. By segmenting the shield wire there is no circulating path for fundamental frequency current induced from the mutual coupling with phase conductors, therefore there is little if any ohmic losses in the shield wire when it is segmented. Because the mutual coupling of the line currents in the phase conductors is the significant factor, losses in an un-segmented shield wire increase with line loading. Ameren Missouri currently has no available capital to deploy in this area.

Since the EPRI study was completed a few years ago, Ameren Missouri requested ABB to review its EHV transformer specification to determine if new EHV transformers it purchases are still considered high-efficiency compared to EHV transformers typically purchased by other utilities. As documented in the ABB report provided in Appendix B, the EHV transformers that Ameren Missouri would purchase in the future will be significantly more efficient than those that other utilities typically purchase. Ameren Missouri's EHV transformer overvoltage operating requirements and monetary loss evaluation value drive a very high no-load loss efficiency. The economic factors that drive the monetary load-loss evaluation value would have to more than triple before a 5% improvement in load-losses would be achieved. As indicated in the report, a 20% increase in purchase price would only gain a 0.0484% increase in efficiency.

7.1.8 Ameren Missouri Affiliates Relationship[19]

Ameren Missouri's focus is upon continuing to provide safe and reliable service to its customers. Ameren Missouri has prioritized its capital investments to address local issues including: improvements to its aging distribution and transmission infrastructure and energy centers, accomplish mandated environmental investments, implement mandated transmission upgrades (e.g., for NERC compliance), and to comply with other state and federal mandates (such as the Missouri RES). These kinds of investments must be made to deliver safe and reliable service to Ameren Missouri's customers.

[19] 4 CSR 240-22.045(3)(B)5; 4 CSR 240-22.045(5)

As mentioned previously, in MTEP11, the MISO approved a portfolio of 17 transmission projects called Multi-Value Projects (MVPs), which stretch across the MISO footprint. This set of MVPs are premised on the integration of local and regional needs into a transmission solution that, when combined with the existing transmission system, provides the least cost delivered energy to customers. Specific projects were included in the portfolio based upon their benefits to the regional transmission system.

A section of this MVP portfolio will traverse a portion of the Ameren Missouri territory. These transmission projects are identified in MTEP11 as MVPs 7, 8 and 9.

An Ameren Missouri affiliate, Ameren Transmission Company of Illinois (ATXi), plans to build the MVP projects. Ameren Missouri's relationship with ATXi is that Ameren Missouri, like ATXi, is a wholly-owned subsidiary of Ameren Corporation. Ameren Missouri does not plan to construct these projects because it is in the best interests of its Missouri customers that it invest its limited capital only in generation, distribution and transmission investments needed to safely and reliably serve its load including the transmission improvements needed to connect an Ameren Missouri generating unit to the grid. Because of its limited capital, Ameren Missouri has concluded that it should not invest its limited capital in other transmission projects, such as MVPs because investing in regional transmission would undermine Ameren Missouri's ability to deliver safe and reliable service. The building of the MVPs by Ameren Transmission Company of Illinois will not impact the cost of the project relative to construction by Ameren Missouri.

7.2 Distribution

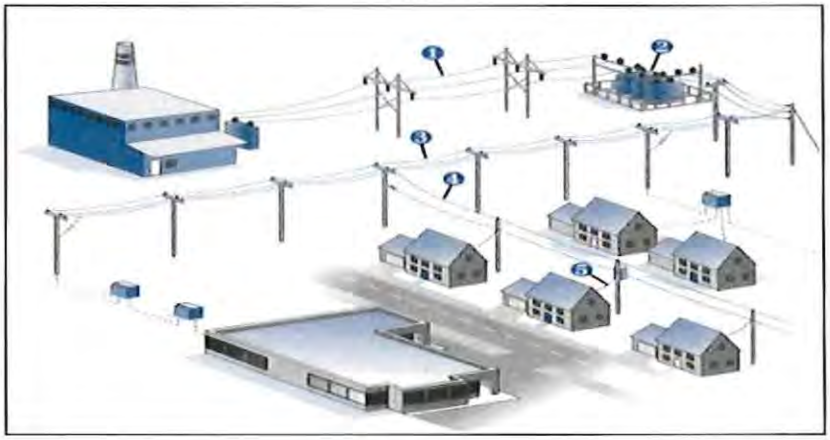
7.2.1 Existing System[20]

Ameren Missouri delivers electricity to approximately 1.2 million customers across central and eastern Missouri, including the greater St. Louis area, through distribution system power lines that operate at voltage levels ranging from 2,400 volts (V) through 69,000 V. Ameren Missouri has 33,000 circuit miles of electric distribution lines, which move electricity into the 63 counties and more than 500 communities where businesses operate and people live.

Approximately 70% of Ameren Missouri's distribution system operates at 12,470 V, 12% operates at 4,160 V and 11% operates at 34,500 V. The remainder operates at other nominal voltage levels. (See Figure 7.1 for further information.)

[20] 4 CSR 240-22.045(1)

Figure 7.1



Here's how the power flows from a power plant to an electric customer:

1. Electricity travels from the power plant over high-voltage transmission lines.
2. At a substation, the electricity's voltage is lowered so that it can travel over the distribution system.
3. Main distribution power lines, typically 3-phase circuits, bring electricity into communities.
4. Local distribution power lines serve neighborhoods and individual customers.
5. Service drops carry electricity from pole-mounted or pad-mounted transformers - which lowers the voltage again - to customer premises.

Much of the distribution system in rural areas is supplied via single substations operating in radial configurations. Long distribution feeders are usually required to serve multiple isolated communities. Long feeders are usually equipped with automatic reclosers to interrupt fault currents and isolate damaged sections, thereby restoring service to upstream portions of the feeder. Where possible, normally open tie switches are installed in downstream sections of feeders to provide emergency service from another source during upstream forced outages. The company installs capacitors and/or voltage regulators, as necessary, to counteract voltage drop and maintain proper voltage levels along lengthy circuits.

A more interconnected distribution system is justified to serve densely populated urban areas. Although substations operate in radial configurations, two or more supply circuits are normally available on the primary side of substation transformers. Each customer is served by a single power source at any given time, but the company can re-configure the interconnected system to maintain service to customers via alternate sources when portions of the system must be de-energized to perform maintenance or complete repairs. Although voltage levels tend to be less of an issue in closely coupled, interconnected systems, the company does employ capacitors to maintain power factor within prescribed limits.

Finally, a portion of the distribution system is networked, which means customers are continuously connected to more than one source. Examples include the 208Y/120 V underground distribution network in downtown St. Louis and the 69,000 V network that supplies communities throughout central Missouri, including Jefferson City, Kirksville, Moberly and Montgomery City. Networked systems offer the advantage of supplying customers from more than one source, so they are not as susceptible to a total loss of power; but, since the system is networked, disturbances in the distribution system tend to affect a larger number of customers. Automatic isolation of faulted equipment and control of power flow in networked systems are more difficult than in radial systems. For these and other reasons, the company employs networked systems on a limited basis in Missouri.

Ameren Missouri's distribution system includes both overhead and underground power lines at the low and medium voltage distribution levels. Underground lines (22% of the total) are more aesthetically pleasing and less vulnerable to weather-caused damage, but they take longer to repair upon failure and are significantly more expensive to install and replace.

Ameren Missouri's distribution system adequately fulfills its fundamental objective of providing service to all customers under peak load conditions. In addition, the vast majority of the system can adequately serve peak load under single contingency conditions. Over the past three years, Ameren Missouri's System Average Interruption Frequency Index (SAIFI) has outperformed the company's target value (SAIFI is below the 2013 target value of 0.96).

7.2.2 System Inspection[21]

Ameren Missouri assesses the age and condition of distribution system equipment with regular inspection, testing and equipment replacement programs, as described below.

Circuit and Device Inspections

Ameren Missouri inspects distribution circuits (4,160 V to 69,000 V) at least every four years in urban areas and six years in rural areas, in compliance with Missouri PSC Rule 4 CSR 240-23.020, to protect public and worker safety and to proactively address problems that could diminish system reliability. The program includes follow-up actions required to address noted deficiencies. Inspections include all overhead and underground hardware, equipment and attachments, including poles. Infrared inspections are performed on overhead facilities, underground-fed transformers and

[21] 4 CSR 240-22.045(1)(A)

switchgear to detect any abnormalities in equipment. Wooden poles are treated every 12 years as appropriate for purposes of life extension. Inspectors may also measure impedance of the static-protected grounding system. Through this program, Ameren Missouri also inspects all line capacitors and voltage regulators on an annual basis. Reclosers and sectionalizers are inspected on a 4-year cycle. Any inoperable capacitor cells are repaired or replaced, helping to ensure optimal power factor system-wide. Ameren Missouri also replaces a number of transformers each year with higher efficiency units when corrosion, oil leaks or other visually detectable issues occur.

Underground Cable Replacements

Sections of single phase or three phase direct buried cable are replaced when the failure history of the cable or cable section is excessive. Once a cable qualifies for replacement, a local engineer studies its performance, as well as the performance of the lateral on the other side of the "normal open" if it is looped, in order to determine how much cable (if any) will be replaced.

Cables that have failed but do not satisfy any of the criteria also may be replaced based on local engineering judgment, with Ameren Missouri personnel making the case for replacement based on field observations and other necessary investigations.

Substation Asset Management

Ameren Missouri schedules substation maintenance to maximize reliability of equipment, and selectively performs various diagnostic tests to obtain meaningful data to predict and prevent failures. Many tests, such as infra-red scanning to detect abnormal equipment heating, can be performed with the equipment in-service. Corrective maintenance is scheduled largely on the basis of diagnostic data, with the intent of restoring equipment to full functionality. When it is no longer practical to make repairs, old equipment is replaced by new with an emphasis on system automation, efficiency and reduction of losses.

Conversion of Dusk-to-Dawn and Municipal Street Lighting

Ameren Missouri has replaced all mercury vapor lights with more efficient high-pressure sodium lights (or metal halide for color sensitive applications). The company continually monitors the development of more efficient lighting technology, with an emphasis on cost/benefit assessment, for potential application on the Ameren Missouri system.