6. New Supply Side Resources

Highlights

- *Ameren Missouri selected two natural gas and one coal technology as final candidate resource options – Gas Combined Cycle, Gas Simple Cycle Combustion Turbine, and Ultra-super-critical Pulverized Coal with carbon capture. 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 without tax incentives. Ameren Missouri has evaluated options for development of wind resources both within Missouri and across the broader region.*
- *Westinghouse's AP1000 technology, which is currently being implemented in projects under construction in the U.S., was selected as the nuclear resource option.*
- *Pumped Hydro was selected as the candidate storage option due to its cost advantage over other options and relative maturity of the technology.*
- *Solar was included among the candidate resource options due to its continued cost improvements and its recognized ability to provide substantial capacity benefits in MISO.*

The supply-side screening analysis of various coal and gas power generation technologies used in the 2014 IRP was reviewed by Ameren Missouri subject matter experts and updated as needed for use in the 2017 IRP. Three technologies 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 selected the Westinghouse AP1000 as the nuclear resource to be evaluated in integration analysis to generally represent new nuclear technology. This technology is currently being implemented through projects under construction in state of Georgia and in China.

Ameren Missouri subject matter experts reviewed and updated the renewable energy potential study conducted by Black and Veatch for use in our 2014 IRP. The study considered solar, wind, landfill gas, hydroelectric, anaerobic digestion, and biomass resources. It should be noted that a new renewable potential study was not conducted because 1) the results of the 2013 study were substantially similar to those of the 2009 study, also performed by Black and Veatch, and 2) there was no expectation, based on a review of publicly available sources, that other renewable technologies would be determined to be more cost effective than those previously identified: wind, solar, hydro and biomass co-firing.

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. While battery storage technologies have not been selected for integration analysis, it is important to note that the use cases for such technologies continue to develop, as does the consideration of appropriate market treatment for the services that these technologies can provide. Such ongoing developments will continue to be considered as part of our ongoing resource planning, including consideration of technologies and services provided by and to the transmission and distribution systems.

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]

6.1 New Thermal Resources[2]

6.1.1 Potential Coal and Gas Options

Ameren Missouri selected two base load, two intermediate load and three peaking load technologies that had passed fatal flaw screening and had been included in the preliminary screening of its 2014 IRP as preliminary candidate resources. Only one of these options represents coal-fired technology, and they are listed below in Table 6.1.

The cost, performance and operational characteristics of these technologies were reviewed and updated by Ameren Missouri subject matter experts and these options were subjected to a preliminary screening. The purpose of the Preliminary Screening was to provide an initial ranking of the evaluated resource options. A scoring methodology was developed with the intent of 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.

[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)

Table 6.1 Preliminary Candidate Options[3]

Fuel Type	Base Load Technologies
Coal	Greenfield - USCPC w/ Carbon Capture
Gas	Greenfield - Molten Carbonate Fuel Cell
	Intermediate Load Technologies
Gas	Greenfield - 2x1 Wartsila 20V34SG
Gas	Greenfield - 7FA (Profile 2)
	Peaking Load Technologies
Gas	Greenfield - Twelve Wartsila Recip. Engines
Gas	Mexico - One LM6000 Sprint
Gas	Greenfield - Two 501Fs (5% CF)

Numerical scores were assigned according to how each option met each 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 A. It is important to note that the coal option with carbon capture did not include any sequestration costs. Ameren Missouri estimated the sequestration costs per MWh generated using estimates from a National Energy Technology Laboratory report[4]. The report estimated CO_2 transportation and storage cost at $10.95/ton in 2011 dollars, which equates to a total of $12.07/ton in 2016 dollars using a 2% escalation rate.

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.

Table 6.2 Candidate Coal and Gas Options

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

Based on the screening analysis, it was concluded that USCPC with carbon capture and sequestration (CCS) 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

[3] 4 CSR 240-22.040(2)(C)
[4] https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev3_20140514.pdf, page 28

option if this resource option were to be selected for implementation. Gas Combined Cycle exhibits the lowest cost on a levelized cost of energy basis among conventional generation resources. The potential candidate resource options with selected operating and cost characteristics, including the LCOE, are listed in Table 6.3. The preliminary screening analysis and technology characterization can be found in Chapter 6 – Appendix A.

Table 6.3 Candidate Coal & Gas Resources

Resource Option	Technology Description	Plant Output (MW)	Total Project Cost Including Owners Cost,Excluding AFUDC ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capacity Factor	Forced Outage Rate	LCOE (¢/kWh)
Greenfield - USCPC w/ Carbon Capture	Coal	679	$5,786	$36.0	19.6*	85%	8%	15.30
Greenfield - Combined Cycle	Gas	600	$1,282	$8.1	$4.2	45%	2%	7.64
Greenfield - Simple Cycle	Gas	352	$702	$7.9	$17.5	5%	5%	24.89

* Includes carbon transportation and storage cost

6.1.2 Potential Nuclear Resources[5]

Ameren Missouri reviewed the state of new nuclear generation candidates currently available and selected the Westinghouse AP1000 to represent potential new nuclear resource options. This was based upon the AP1000 being the only candidate to have a current approved U.S. Nuclear Regulatory Commission (NRC) Design Certification and being the only Generation III+ reactor design that is under construction within the United States. The nuclear technology characterization can be found in Chapter 6 – Appendix A.

AP1000

The AP1000 is a Generation III+ reactor that is rated at 1,110 MWe. This design is an evolution of earlier Westinghouse Pressurized Water Reactor (PWR) designs. This design is modular in nature and has fewer active components than previous designs, which should reduce construction, maintenance, staging, testing and inspection requirements.

Currently, there are six AP1000 reactors under construction worldwide. The plant designer, Westinghouse has incurred financial difficulties and declared bankruptcy in March 2017. Due to the loss of fixed price options that were invalidated with bankruptcy, the owners of the Summer 2-3 plants stopped construction in July 2017. Table 6.4 lists the currently active AP1000 projects and expected in-service dates.

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

Table 6.4 AP1000 Projects Worldwide

Project	Country	Expected In-Service Date
Sanmen 1	China	2018
Sanmen 2	China	2018
Haiyang 1	China	2018
Haiyang 2	China	2018
Vogtle 3	United States	2019
Vogtle 4	United States	2020

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 U.S. AP1000 projects that were current prior to the Westinghouse bankruptcy declaration and may be subject to revision as this financial situation proceeds through the court system.

Table 6.5 U.S. AP1000 Capital Costs

<table>
<tr><th>Project</th><th>Construction Start</th><th>Cost* /Source</th><th colspan="2">Summary 2016 Costs</th></tr>
<tr><td>Summer 2 and 3
2 x AP1000
2200 MW</td><td>2013</td><td>$7.2B for SCE&G 55% share --> $13.1B
VC Summer Quarterly Report 3-31-16</td><td rowspan="2">With AFUDC

$6,000-$7,800 per kW</td><td rowspan="2">Without AFUDC

$5,400-$6,000 per kW</td></tr>
<tr><td>Vogtle 2 and 3
2 x AP1000
2200 MW</td><td>2013</td><td>$7.9B for GPC 45.7% share --> $17.1B
15th VCM Report 8-31-16</td></tr>
</table>

* Costs include AFUDC.

The capital and operational costs for the potential nuclear candidate resource option to be used in the 2017 IRP are listed in Table 6.6. The nuclear LCOE calculations are based on a 40 year economic life.

Table 6.6 Candidate Nuclear Resource

Resource Option	Plant Output (MW)	Project Cost with Owner's Cost, Excluding AFUDC ($/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	$6,134	$13,975	$149	$2.3	94%	2%	12.34

Generation IV Reactors

While the current generation of available nuclear resource options consists of Generation III+ light water reactors, in the next 15 to 20 years there is a high likelihood that Generation IV reactors will become an available option. These reactors differ from their Generation III counterparts by using different coolants, fuel, and plant designs. The prominent leaders in this field include the General Electric Prism design (sodium cooled fast reactor), Westinghouse Lead Cooled reactor (lead cooled fast reactor), and the Terrestrial Energy Integral Molten Salt Reactor (uranium fueled molten salt reactor). Development of these reactor designs is currently on a path that they could lead to commercial deployment in the early 2030's. These innovations in reactor design and plant construction could lead to highly improved economics that could make nuclear power an attractive future resource option.[6]

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. The information gathered through this analysis was reviewed by Ameren Missouri subject matter experts and updated as needed for use in the 2017 IRP. A detailed characterization of the potential projects can be found in Chapter 6 – Appendix B.

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 landfill gas (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.

[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)

Landfill Gas Overview

Landfill gas 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.

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.

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.

During the 2013 study, 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. 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) each of LFG-fired generation capacity:

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

Ameren Missouri subject matter experts reviewed the information and, based on the experts' judgment, determined it was appropriate to use for the 2017 IRP. 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 MHREC 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 B contains more detailed information.

Table 6.7 Potential Landfill Gas Resources

Resource Option	Technology Description	Plant Output (MW)	First Year Fuel Cost, ($/Mbtu)	Project Cost with Owner's Cost, Excluding AFUDC ($/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	$2.65	$4,659	$118	$12.3	90%	8%	13.10
Maple Hill	RICE	4	$2.65	$4,563	$118	$12.3	90%	8%	13.45
Timber Ridge	RICE	3	$2.65	$4,966	$127	$11.1	90%	8%	13.98
Lemons East	RICE	3	$2.65	$4,966	$127	$11.1	90%	8%	13.98
Eagle Ridge	RICE	2	$2.65	$5,614	$191	$12.6	90%	8%	15.94
Missouri Pass	RICE	2	$2.65	$5,614	$191	$12.6	90%	8%	15.94

6.2.2 Potential Hydroelectric Projects

Ameren Missouri subject matter experts utilized the 2013 Black & Veatch Renewable Potential Study, a report prepared by Oak Ridge national Laboratory for the U.S. Department of Energy Wind and Power program (Oak Ridge report)[8], a report prepared by the Hydropower Analysis Center for the USACE Headquarters (USACE report)[9], and EIA's 2017 Annual Energy Outlook[10] to identify and characterize hydroelectric projects.

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.

Developable renewable hydropower resources are constrained by several factors, including the following:

[8] An Assessment of Energy Potential at Non-Powered Dams in the United States, April 2012
[9] Hydropower Resource Assessment at Non-Powered USACE Sites, July 2013
[10] EIA AEO 2017 - Capital Cost Estimates for Utility Scale Electricity Generating Plants

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

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.”

According to several studies[11] conducted since 2012, significant growth in hydroelectric generation capability exists within the United States. The vast majority of this growth is expected to be achieved by adding electric generation capability to existing dams, referred to as non-powered dams. There are around 83,000 dams in the U.S. and less than 3,000 of these dams have existing generation structures.

Candidate Hydroelectric Project Identification and Characterization

Both the Oak Ridge and USACE reports identified potential hydropower sites and prioritized them based on different criteria. Oak Ridge report indicates five of the top 26 non-powered dams with hydropower potential are Mississippi River dams owned by the USACE in or near Ameren Missouri’s service territory, along the Illinois/Missouri border between Quincy, Illinois and St. Louis. The USACE report excluded some sites and used a Benefit Cost Ratio (BCR) to prioritize the Corps dams, which showed two of the top 20 dams in the country were the Clearwater Dam and the Melvin Price (L&D 26, Alton) dams in or near Ameren Missouri’s service territory.

Table 6.8 contains details of the potential hydroelectric projects. These projects were evaluated assuming a 60-yr economic life. Chapter 6 – Appendix B 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,

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[11] The Oak Ridge report.
The USACE report
Hydropower Vision, A New Chapter for America’s 1st Renewable Electricity Source, U.S. Department of Energy Wind and Waterpower Technologies Office, October 26, 2016
World Energy Resources, World Energy Council, October, 2016

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)	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capacity Factor (%)	Forced Outage Rate (%)	Current FERC Permit	LCOE (¢/kWh)
L&D 21, Quincy	6	$5,285	$25	$0.0	62%	3%	No	10.31
L&D 22, Saverton	8	$4,500	$25	$0.0	56%	3%	Yes	9.81
L&D 24, Clarksville	30	$3,123	$25	$0.0	58%	3%	Yes	6.84
L&D 25, Winfield	30	$3,123	$25	$0.0	52%	3%	Yes	7.64
L&D 26, Mel Price	75	$3,123	$25	$0.0	55%	3%	Yes	7.14
Clearwater	5	$4,224	$25	$0.0	52%	3%	No	12.98
Pomme de Terre	5	$3,990	$25	$0.0	55%	3%	No	8.21

As can be seen from Table 6.8, four of the potential sites have preliminary FERC permits. It is common today for hydro development companies to apply for and receive FERC permits to evaluate development at sites; however, the developers are not always able to follow through with development of the site. If they are not ready to start construction and pursue a full FERC license at the end of the permit period, they surrender the permit and the sites would be open for other developers. Therefore, Ameren Missouri will be following the developments in these sites; however, the three projects that don't have existing FERC licenses passed as candidate hydro resources for further evaluation in the 2017 IRP.

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. There are 242 operational anaerobic digestion projects as of May 2016 in the U.S. generating 981,000 MWh of electricity in 2015.[12]

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 B contains more detailed information.

Table 6.9 Potential Anaerobic Digestion Resources

Resource Option	Livestock Type	Plant Output (MW)	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	Forced Outage Rate (%)	LCOE (¢/kWh)
Newton County 1	Layers	4.5	$8,288	$1,029	$0	90%	8%	27.14
Mercer County 1	Swine	3.9	$8,373	$1,051	$0	90%	8%	27.54
Putnam County 2	Swine	3.2	$8,522	$1,061	$0	90%	8%	27.93
Mercer County 2	Swine	3.1	$8,575	$1,061	$0	90%	8%	28.01
Putman County 1	Swine	2.5	$8,744	$1,072	$0	90%	8%	28.45
Gentry County 1	Swine	2.1	$8,935	$1,093	$0	90%	8%	28.97
Gentry County 2	Swine	2.1	$8,999	$1,093	$0	90%	8%	29.10
Sullivan County 4	Swine	2.1	$8,999	$1,093	$0	90%	8%	29.10
Sullivan County 2	Swine	1.8	$9,148	$1,104	$0	90%	8%	29.47
Lewis County 1	Dairy	1.7	$9,222	$1,114	$0	90%	8%	29.70
Vernon County	Swine	1.7	$9,222	$1,114	$0	90%	8%	29.70
Harrison County	Layers	1.6	$9,317	$1,125	$0	90%	8%	30.04
Sullivan County 3	Swine	1.6	$9,317	$1,125	$0	90%	8%	30.04
Lincoln County 1	Layers	1.4	$9,551	$1,146	$0	90%	8%	30.68
Mercer County 3	Swine	1.2	$9,859	$1,167	$0	90%	8%	31.45
Mercer County 4	Swine	1.1	$10,050	$1,178	$0	90%	8%	31.82

[12] https://www.epa.gov/agstar/agstar-data-and-trends

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 dispersed 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.

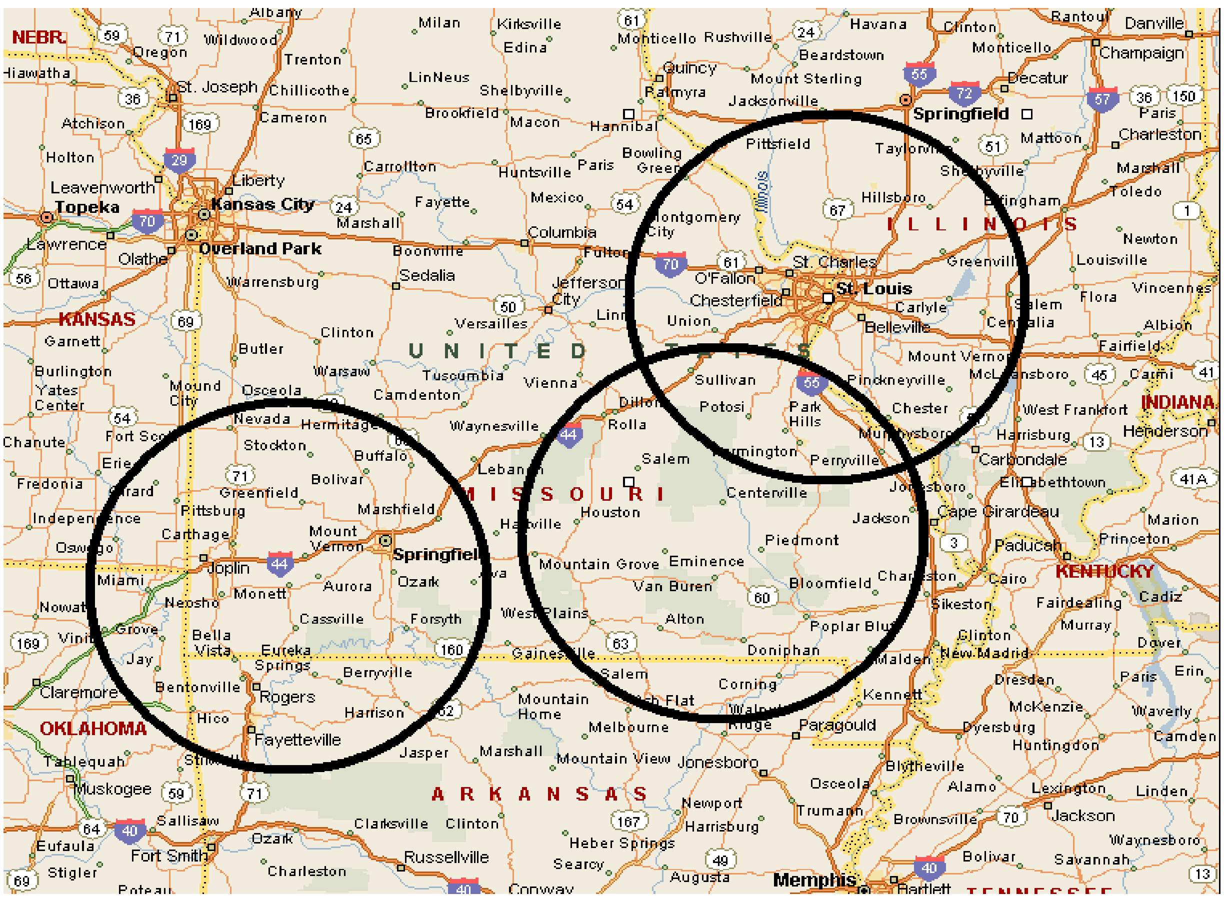
There are several methods of biomass co-firing that could be employed for a project. The most appropriate system is a function of the biomass fuel properties and the coal boiler technology. Provided they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require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

Figure 6.1 Selected Biomass Study Regions



The purpose of the Preliminary Screening was to provide an initial ranking of the evaluated resource options. A scoring methodology was developed with the intent of 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.

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 ($4.78/loaded mile in 2016$) 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:

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

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 B.

Table 6.12 Biomass Resource Fuel Requirements

Project Location	Net Capacity* (MW)	Fuel Supply Identified (MMBtu/day)	Available Fuel Supply** (MMBtu/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

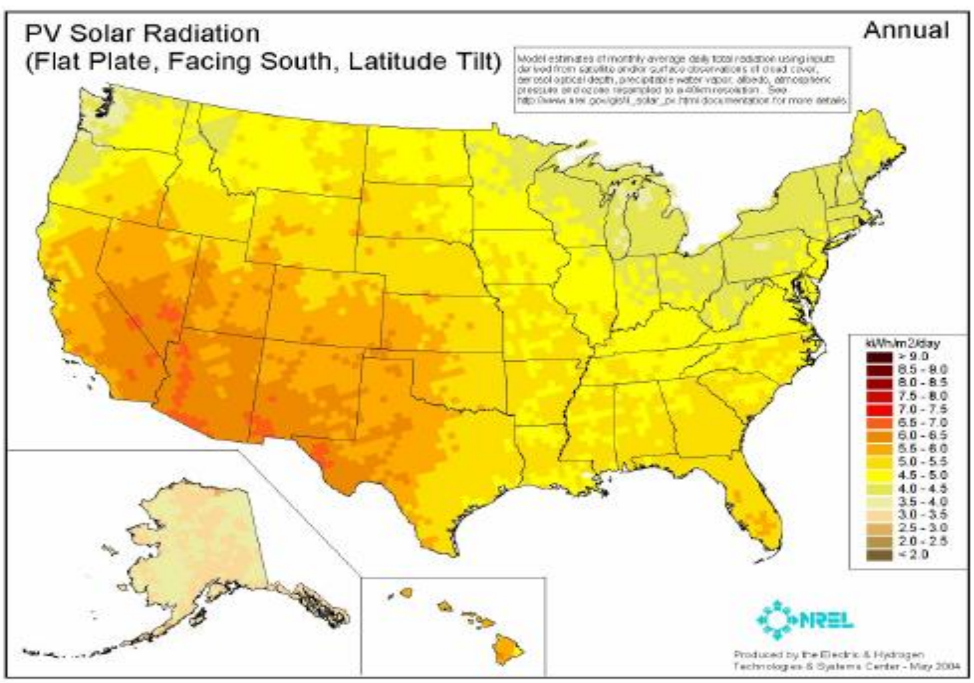
Project Location	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Fuel Type/Source	First Year Fuel Cost, ($/MMbtu)	Forced Outage Rate (%)	LCOE (¢/kWh)
St. Louis (co-firing)	1,029	$51	$0	Wood	3.24	8%	6.02
Ellington (standalone)	9,583	$326	$17	Wood	3.35	10%	27.57
Monett (standalone)	6,962	$170	$13	Wood/Litter	3.02	10%	19.96

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 use a direct component of insolation, called direct normal insolation (DNI). Given Missouri's low DNI resource, currently, PV is the most cost effective form of solar technology.

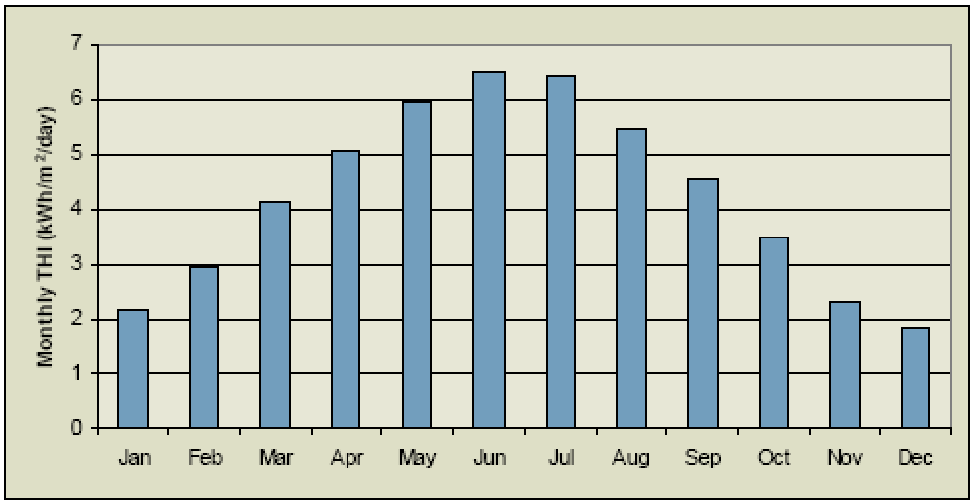
Figure 6.2 U.S. Global Horizontal Insolation Map



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 6.2. 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 6.3 shows the monthly average GHI for St. Louis.

Figure 6.3 Monthly Average Global Horizontal Insolation for St. Louis



Flat Plate Photovoltaics

Currently, the United States' largest photovoltaic solar generating facility is the Solar Star photovoltaic power station near Rosamond, CA. Completed in 2015, it is a 579 MW (AC) facility with approximately 1.7 million panels. In 2016, SEIA reported there was over 13,382 MW of large-scale PV solar (>1MW) operating in the U.S., 9,160 MW under construction, and 32,990 MW under development. Of the combined 2016 PV and CPV capacity in U.S., PV made up 89% of the total operating capacity, 99.5% of the solar under construction, and 98% of the solar under development. The cost decreases that PV technology has realized over the last 3 years, has quickly made it the technology of choice for large-scale solar deployment.

Ameren Missouri Photovoltaics

Ameren Missouri owns approximately 100 kW (AC) of various PV solar technologies at its headquarters office building and 4.8 MW (AC) fixed-tilt solar photovoltaic generation facility, O'Fallon Renewable Energy Center (OREC), in St. Charles County.
The company also plans to build a solar facility along the I-70 corridor in Montgomery County almost 4 times the size of OREC on approximately 90 acres by 2020. This

facility would meet the total kWh load requirements of nearly half of the homes within the county.

Table 6.14 lists the primary characteristics of solar resources. Cost assumptions from the 2013 Black and Veatch study were reviewed with internal subject matter experts and revised as appropriate. Chapter 6 – Appendix B contains more detailed information.

Table 6.14 Potential Solar Resource

Resource Option	Plant Output (MW)	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	Forced Outage Rate (%)	LCOE without Incentives (¢/kWh)
Solar	13.2	$1,863	$16	$0	19.0%	1%	11.34

Table 6.15 shows U.S. average cost breakdowns for various fixed tilt sizes and large single axis tracking. The table is from a report prepared by GTM Research- PV Balance of Systems 2015: Technology Trends and Markets. Ameren expects that on average the cost of solar will continue to decline, by approximately 4 to 5% over the next 5 years- at a much slower pace than what the industry has experienced over the last 8 years.

Table 6.15 U.S. PV System Installed Cost by System Type ($/W) **

CONFIDENTIAL

**

PUBLIC

Innovative Photovoltaic Deployment

Ameren Missouri is exploring various methods to incorporate and deploy more solar generation throughout its service territory. Two of these methods are the Subscription Solar Pilot and the Solar Partnership Pilot.

The Subscription Solar Pilot will install additional solar capacity once enough customers have subscribed to a minimum amount of output from a proposed solar facility. Once the facility is completed, these customers will be billed for the kilowatt-hours they subscribe to under a separate tariff. The pilot would provide interested customers an opportunity to support additional solar and fix the price of the solar generation they pay for under the program to meet a portion of their load. The initial pilot, should it receive full subscription, will provide approximately 1MW of solar generation to Ameren Missouri customers.

The Solar Partnership Pilot seeks to explore opportunities between Ameren Missouri and its customers in regards to siting utility-owned solar generation on customer property, and the potential benefits and challenges with siting smaller distributed generation closer to major load centers. This approach will attempt to minimize the distance from production to consumption, while maximizing the use of existing developed or underdeveloped space that could also serve as a solar generation facility. These opportunities could come in many forms, from rooftops, covered parking lots, or land that has building restrictions and limited development opportunities. Under the pilot, the company would limit its spend on each site to no more than $2.20/watt of the total plant installation cost. In any project, where the scope of the installation causes the total cost to exceed this cap, a contribution in excess of the cap would be required from the customer partner prior to Ameren Missouri proceeding with the build. If successful, the pilot is projected to add an aggregate of approximately 5 to 6 MWs of solar generation to the Ameren Missouri portfolio.

6.2.6 Potential Wind Resources

In December, 2015, Ameren Missouri issued a wind RFP to a group of experienced Midwest wind developers for wind projects located in Missouri, Illinois, and Iowa. The Company's preference was for projects located within the MISO footprint, with an even higher preference for projects located in Missouri that are within the MISO footprint, both for RES compliance and economic development purposes in the state of Missouri.

The developers were asked to provide both a Purchase Power Agreement (PPA) option and a build-own-transfer option; most of the developers provided both. Project capacity ranged from 50-200 MW built in the 2017-2019 timeframe. The goal was to identify and potentially reach an agreement with a developer or developers on one or more projects to help meet the company's Missouri RES obligation.

In early 2016, Ameren Missouri received responses from 7 developers representing 13 unique projects. All projects were at varying stages of development. Ameren Missouri is currently in negotiations and anticipates a contract will be executed in 2017.

All of the proposals were based on a 96 meter hub height, which has become more prevalent in recent years. The ranges of prices have significantly dropped since the previous filing of our 2014 IRP, which relied heavily on analysis done by Black & Veatch. In that analysis, capital cost estimates for 100 meter hub height turbines in the Midwest ranged from $2,300 to $2,400/kW. Using the wind developer responses to the Company's RFP request, Ameren Missouri subject matter experts revised the cost and operational characteristics of wind resources to be used in the 2017 IRP. Table 6.16 lists primary characteristics for potential wind resources. Chapter 6 – Appendix B contains more detailed information.

Table 6.16 Potential Wind Resources

Resource Option	Plant Output (MW)	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost, ($/kW)	First Year Variable O&M Cost, ($/MWh)	Assumed Annual Capcity Factor (%)	LCOE without Incentives (¢/kWh)
Missouri Wind	700	$1,859	$26	$0	40.0%	5.80
Regional Wind	1000	$1,866	$26	$0	45.0%	5.17

6.3 Potential Storage Resources[13]

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 C. Four options passed the initial screen: pumped hydroelectric energy storage, compressed air energy storage, and sodium-sulfur (NaS) battery energy storage.

[13] 4 CSR 240-22.040(1); 4 CSR 240-22.040(2); 4 CSR 240-22.040(4)(A)

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 pumped hydroelectric energy storage uses two water reservoirs, separated vertically. During lower priced hours (historically off-peak periods), water is pumped from the lower reservoir to the upper reservoir. During high priced periods, (typically on-peak hours), 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)

The 2015 DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA (Storage Handbook) continues to characterize CAES as the only commercial utility-scale energy storage plant available today, other than pumped hydroelectric energy storage. There are two commercially operating utility scale CAES facilities in the world---one in Alabama and one in Germany. There are three such facilities under consideration in the United States: PGE's Kern County, CA project, Iberdrola's Watkins Glen, NY project and Apex's Anderson County, TX project.

A CAES facility consists of an energy production and energy storage system. The energy production facilities compress air into the storage vessel where it is stored until the plant is deployed. When deployed, 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 Storage Handbook, 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. In such a design, 1/3 of the electrical output of the plant would come from the combustion turbine and the remaining two thirds from the CAES expansion turbine.

The storage vessel for a CAES plant may take various forms, including 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 Storage Handbook. The storage capacity was based on 8 hrs. While CAES technology has been in use for decades, it's very limited deployment (only one operating CAES plant in the U.S.) prevents it from being considered a mature technology like pumped hydro storage.

Battery Energy Storage Systems[14]

The analysis of battery energy storage systems presents unique challenges compared to the analysis of pumped hydro and compressed air storage. The latter resources generally have long discharge times and are larger facilities, potentially reaching a gigawatt in size. Their value is predominantly concentrated in the bulk power management components of capacity and energy, though they are capable of providing certain ancillary services (in particular supplemental reserve service). The potential value of battery energy storage systems, which tend to be of smaller size and shorter discharge durations, is spread across a much greater range of services. There is a question, however, as to whether the MISO market tariffs and rules currently provide a means for owners to realize value for these services.

Indianapolis Power & Light filed a complaint before FERC during October 2016 alleging that the MISO market design does not adequately compensate their Harding Street Station energy storage system for the primary frequency response it provides, and that the MISO tariff and business practice requirements are unfair. These tariff and business practices regarding what services storage resources are allowed to provide, minimum sustainable output levels required to qualify for capacity credits, and other terms and conditions are seen as requiring battery system owners to operate their systems in a suboptimal manner which degrades battery life and frustrates or complicates the analysis of potential value for these resources.

In February 2017, FERC found MISO's tariff to be unjust, unreasonable, and unduly discriminatory or preferential because it unnecessarily restricts competition by preventing electric storage resources from providing all the services that they are technically capable of providing. FERC directed MISO to submit a compliance filing proposing Tariff revisions that accommodate the participation of all electric storage resources, regardless of technology, in all MISO capacity, energy, and ancillary service markets that they are technically capable of participating in, in a way that acknowledges their unique physical and operational characteristics. As a result, MISO proposed very limited Tariff changes including the establishment a new resource type, Stored Energy Resource – Type II or SER – Type II, and provisions to address market offers and settlements. Both IPL and MISO filed requests for rehearing in EL17-8. FERC granted

[14] EO-2017-0073 1.L

the rehearing requests in March 2017 but the outcome will not be determined until a quorum is established again at FERC.

FERC is also addressing electric storage in several other proceedings:

- RM16-6: On November 17, 2016, FERC issued a Notice of Proposed Rulemaking (NOPR) in Docket No. RM16-6 regarding primary frequency response, stating that "(t)he proposed changes are designed to address the increasing impact of the evolving generation resource mix and to ensure that the relevant provisions of the pro forma LGIA and pro forma SGIA are just, reasonable, and not unduly discriminatory or preferential. The Commission also seeks comment on whether its proposals in this Notice of Proposed Rulemaking are sufficient at this time to ensure adequate levels of primary frequency response, or whether additional reforms are needed."
- AD16-20: In April 2016, FERC staff in docket AD16-20, issued data requests to the staffs of various RTO's seeking, "information on rules that affect the participation of electric storage resources in the MISO markets, including, but not limited to, the eligibility of electric storage resources to participate in the MISO markets, the qualification and performance requirements for market participants, required bid parameters, and the treatment of electric storage resources when they are receiving electricity for later injection to the grid." MISO staff indicated that these data requests were issued as they were, "interested in examining whether barriers exist to the participation of electric storage resources in the capacity, energy, and ancillary service markets in the RTOs and ISOs potentially leading to unjust and unreasonable wholesale rates." Staff also expects to examine, if potential barriers exist, whether any tariff changes are warranted. In the attached data request, staff seeks information on rules that affect the participation of electric storage resources in the MISO markets, including, but not limited to, the eligibility of electric storage resources to participate in the MISO markets, the qualification and performance requirements for market participants, required bid parameters, and the treatment of electric storage resources when they are receiving electricity for later injection to the grid."
- AD16-25: In another administrative docket AD16-25, the Commission convened a technical conference in November 2016, "to explore the circumstances under which it may be appropriate for electric storage resources to provide multiple services, whether the RTO/ISO tariffs need to include provisions to accommodate these business models, and how the Commission may ensure just and reasonable compensation for these resources in the RTO/ISO markets."
- PL17-2: FERC issued a policy statement in January 2017 under docket PL17-2 to address cost recovery issues related to electric storage resources. The Commission issued the policy statement to clarify its precedent and provide guidance on the ability of electric storage resources to provide services at and

seek to recover costs through both cost-based and market-based rates concurrently. The Commission previously considered similar issues in *Nevada Hydro*[15] and *Western Grid*[16].

At the time of writing, these issues before FERC remained unresolved.

MISO has initiated a stakeholder process to review existing tariff and business practices governing markets, operations, technology, and transmission planning to determine if changes should be made to facilitate integration of ESR in MISO. The stakeholder process is expected to conclude in Q4 2018.

Ameren Missouri is monitoring technology and cost improvements in the electric storage sector, evaluating system needs for potential battery solutions, participating in MISO stakeholder efforts to revise tariff and business practices, while waiting for FERC to act on ESR-related proceedings. We expect that greater certainty and guidance will be available for the next IRP, allowing the Company to perform a more complete, meaningful analysis of battery systems.

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 Storage Handbook, which also continues to describe the 34 MW Rokkasho wind-stabilization project in northern Japan as the largest single NaS battery installation.

Performance and cost estimates were based on the 50 MW/6 hours NaS bulk storage system provided in the Storage Handbook. The estimated life of a NaS battery is approximately 15 years based on the assumption that the battery is cycled daily.

[15] *The Nev. Hydro Co. Inc.,* 122 FERC ¶ 61,272 (2008) (*Nevada Hydro*)
[16] *Western Grid Dev., LLC,* 130 FERC ¶ 61,056 (*Western Grid*), *reh'g denied,* 133 FERC ¶ 61,029 (2010)

Lithium-ion Batteries

In addition to electric vehicle and backup systems for residential and commercial applications, Li-ion systems have emerged as the preferred choice for new grid- scale storage systems in the United States. AES Energy Storage LLC , has deployed more than 50 MW of systems as an independent power producer (IPP) for frequency regulation and spinning reserve services.

Indianapolis Power and Light's Li-ion Advancion Energy Storage Array was put into commercial operation in May of 2016. This 20 MW/20 MWh facility was the first grid-scale energy storage array in MISO. Currently providing primary frequency response to the MISO grid, IP&L stated that the facility will also enhance grid reliability and deliver ancillary services and peak energy supply.

Unlike other storage systems detailed in the EPRI report, the cost and performance characteristic data for Li-Ion systems were segregated by the intended use of the system; 1) frequency regulation and renewables, 2) Utility T&D Grid Support, 3) Distributed Energy Storage, and 4) Commercial and Residential Applications. Given the focus of the 2017 IRP on capacity and energy, the performance and cost estimates for the 50kW/4hr Advanced Li-Ion system for distributed energy storage provided in the Storage Handbook were utilized. The estimated life of this advanced Li-ion system is approximately 15 years based on the assumption that the system is cycled daily.

Table 6.17 shows the energy storage technologies that were evaluated. Chapter 6 – Appendix C contains more information.

Table 6.17 Potential Energy Storage Resources

Resource Option	Operations Mode	Plant Output, MW	Project Cost with Owner's Cost, Excluding AFUDC ($/kW)	First Year Fixed O&M Cost ($/kW)	First Year Variable O&M Cost ($/MWh)	Heat Rate HHV, Btu/kWh	Annual Capacity Factor, Percentage	LCOE (¢/kWh)
Pumped Hydroelectric Storage	Peaking	600	$1,647	$3.6	$3.6	n/a	25%	12.02
Compressed Air Energy Storage (CAES) with Combustion Tubrine	Peaking	441	$889	$3.3	$3.3	3,760	33%	12.06
Sodium Sulfur (NaS) Battery	Peaking	50	$3,458	$5.1	$0.6	n/a	25%	23.46
Lithium-Ion (Li-Ion)) Battery	Peaking	0.5	$5,393	$30.2	$3.0	n/a	17%	60.19

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.

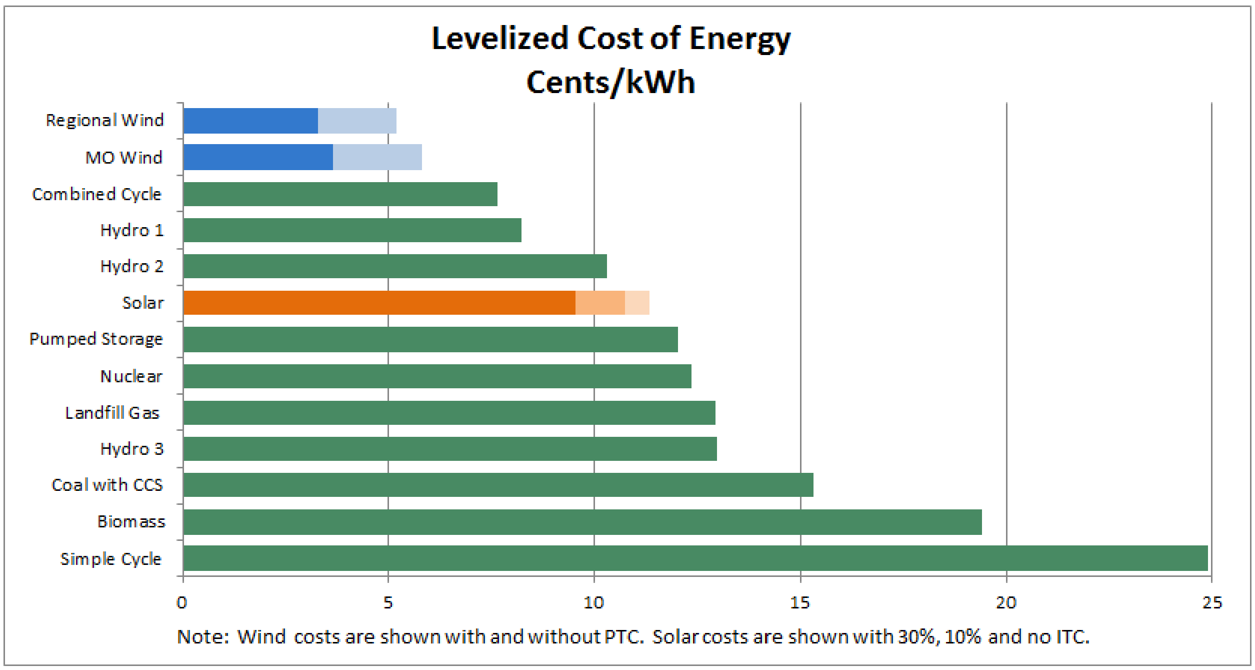
6.4 Power Purchase Agreements

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 reasonable 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 effectively cost-based.

6.5 Final Candidate Resource Options[17]

Figure 6.4 shows the LCOE with incentives (e.g., Investment Tax Credits or Production Tax Credits, if applicable) for a range of potential supply side resources.

Figure 6.4 Levelized Cost of Energy



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 of each resource type. For example, wind resources are intermittent resources and

[17] 4 CSR 240-22.040(4); 4 CSR 240-22.040(4)(C)

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 or their quick-start capability. The levelized cost of wind resources presented in Figure 6.16 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 relatively high cost and the uncertainty of CCS technology.[18] Table 6.18 shows the component analysis for the levelized cost of energy figures.

Table 6.18 Levelized Cost of Energy Component Analysis[19]

Resource	Levelized Cost of Energy (¢/kWh)									
	Capital	Fixed O&M	Variable O&M	Fuel	Pump Cost	Decommission	CO_2	SO_2	NO_X	Total Cost
New Resources										
Regional Wind	4.35	0.83	0.00	--	--	--	--	--	--	**5.18**
MO Wind	4.87	0.94	0.00	--	--	--	--	--	--	**5.80**
Combined Cycle	3.46	0.26	0.52	3.26	--	--	0.14	0.00	0.00	**7.64**
Hydro: Pomme de Terre	7.56	0.65	--	--	--	--	--	--	--	**8.21**
Hydro: Mississippi L&D 21	9.67	0.63	--	--	--	--	--	--	--	**10.31**
Storage: Pumped Hydro	7.17	0.21	0.48	--	4.17	--	--	--	--	**12.02**
Nuclear	8.68	2.36	0.30	0.84	--	0.17	--	--	--	**12.36**
Landfill Gas	5.95	1.75	1.44	3.80	--	--	--	0.00	0.00	**12.94**
Solar	10.14	1.20	--	--	--	--	--	--	--	**11.34**
Hydro: Clearwater	12.00	0.98	--	--	--	--	--	--	--	**12.98**
Coal (USCPC with CCS)	9.08	0.63	2.56	2.97	--	--	0.06	0.00		**15.30**
Biomass	10.50	2.67	1.40	4.84	--	--	--	0.00	0.01	**19.42**
Simple Cycle	17.50	2.25	0.98	3.99	--	--	0.17	0.00	0.00	**24.89**

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 resources in a timely fashion is a prudent course of action.

[18] 4 CSR 240-22.040(2)(C)2
[19] 4 CSR 240-22.040(2)(C)1

6.6 Compliance References