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.

[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.

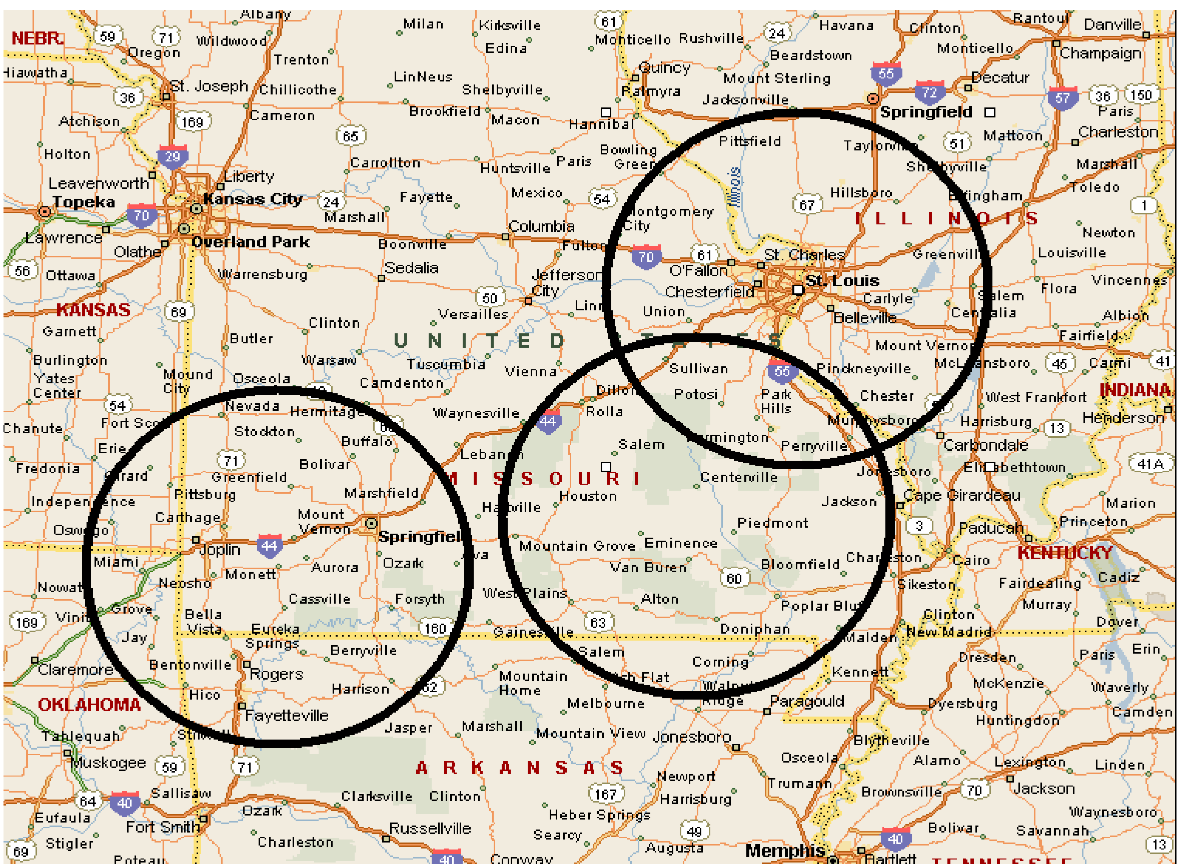
Selected Biomass Inventory Areas

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

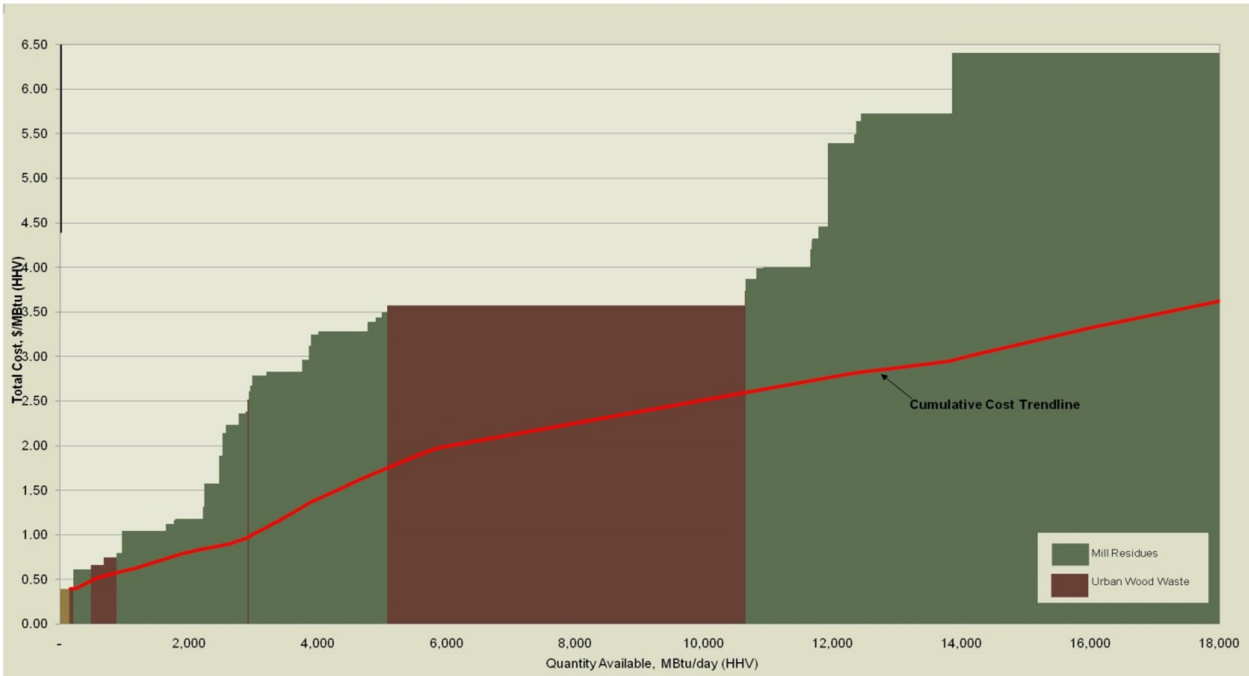


Figure 6.3 Biomass Fuel Supply Curve for Ellington Region

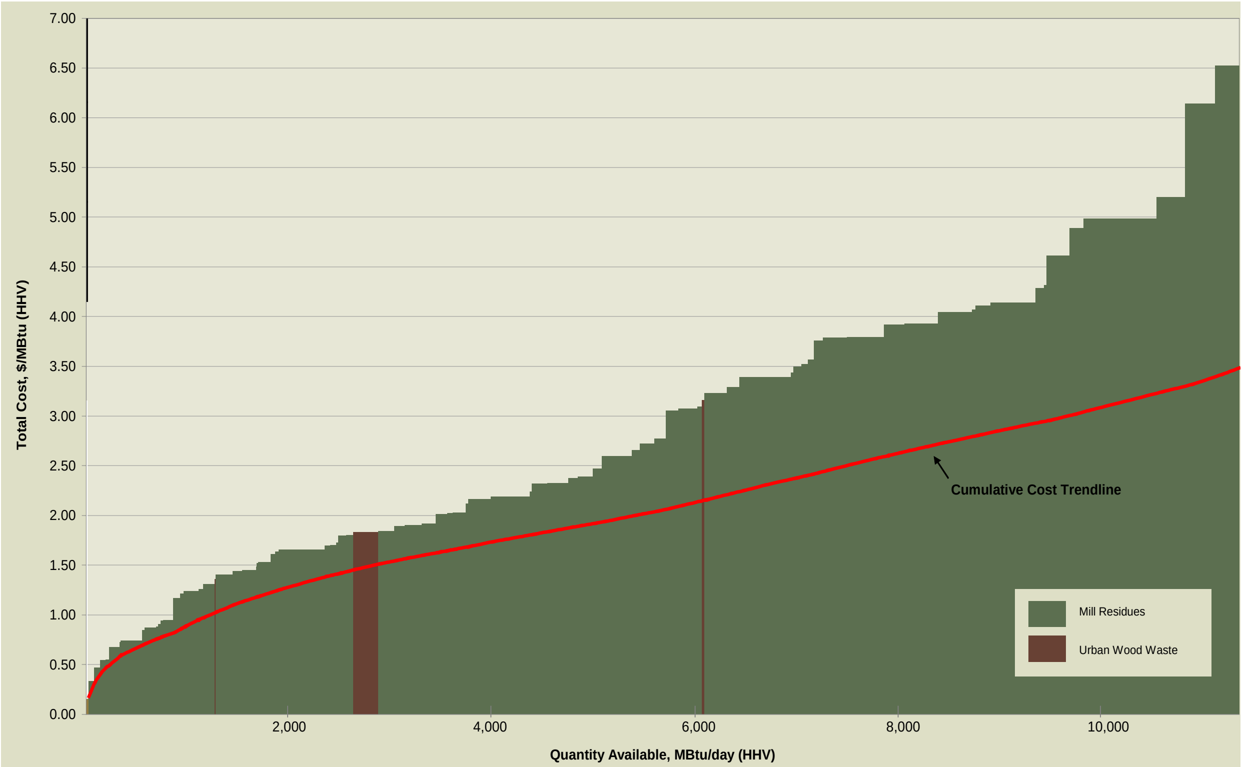
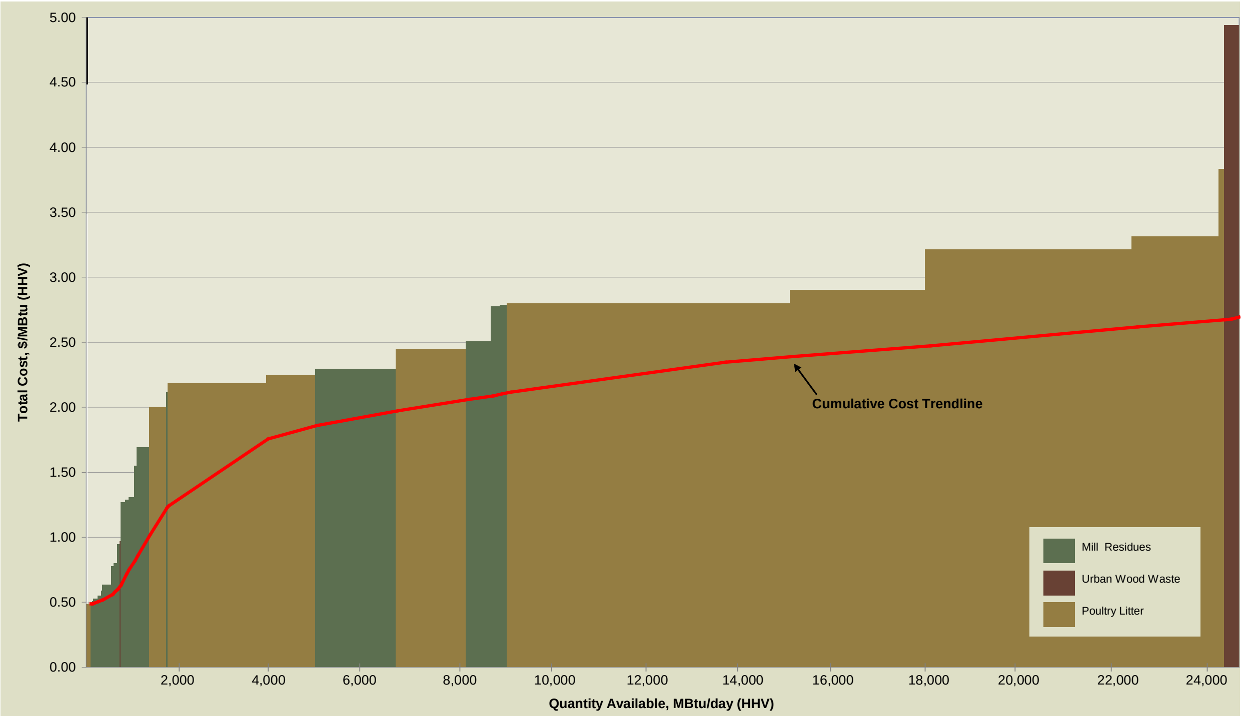


Figure 6.4 Biomass Fuel Supply Curve for Monett Region



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

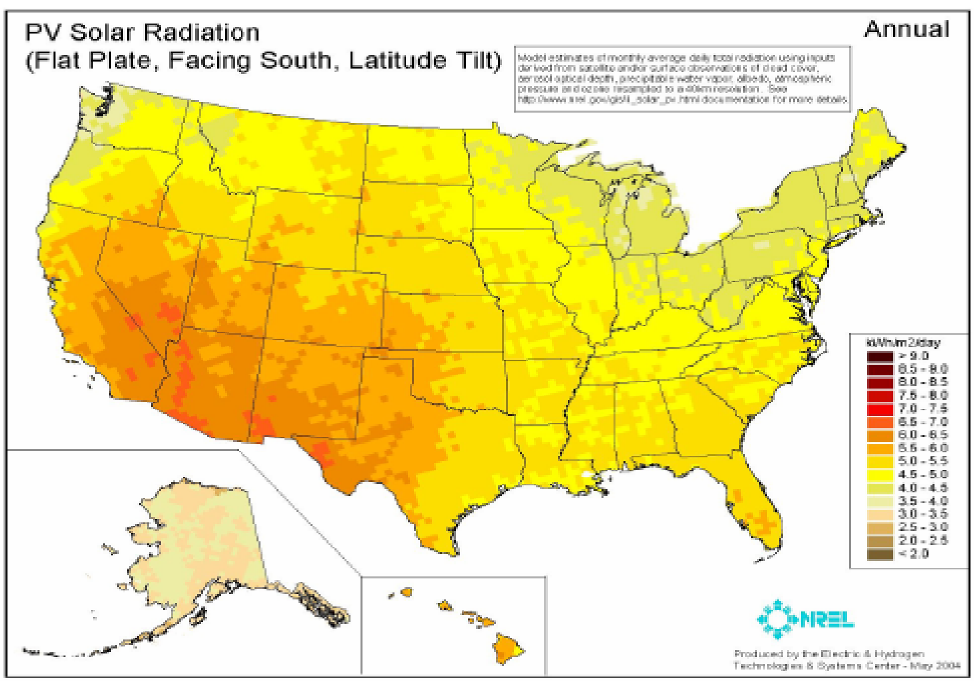
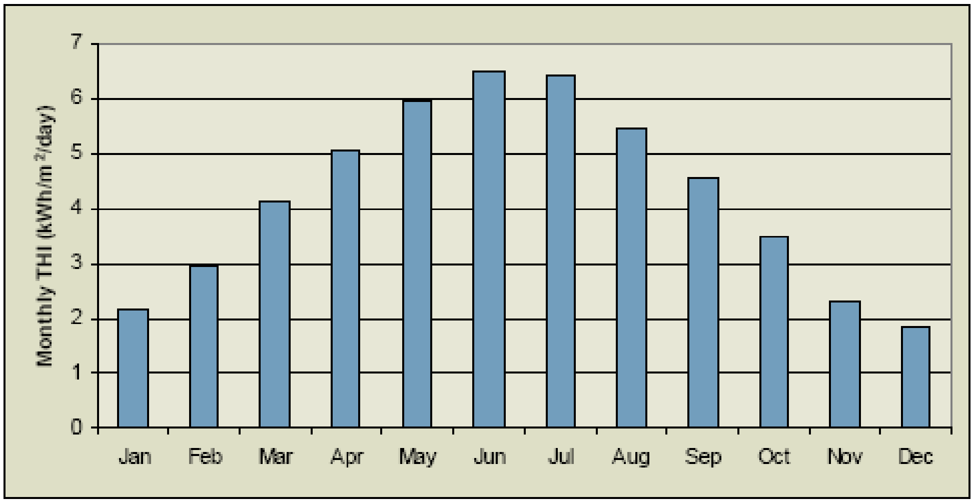


Figure 6.6 Monthly Average Global Horizontal Insolation for St. Louis



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

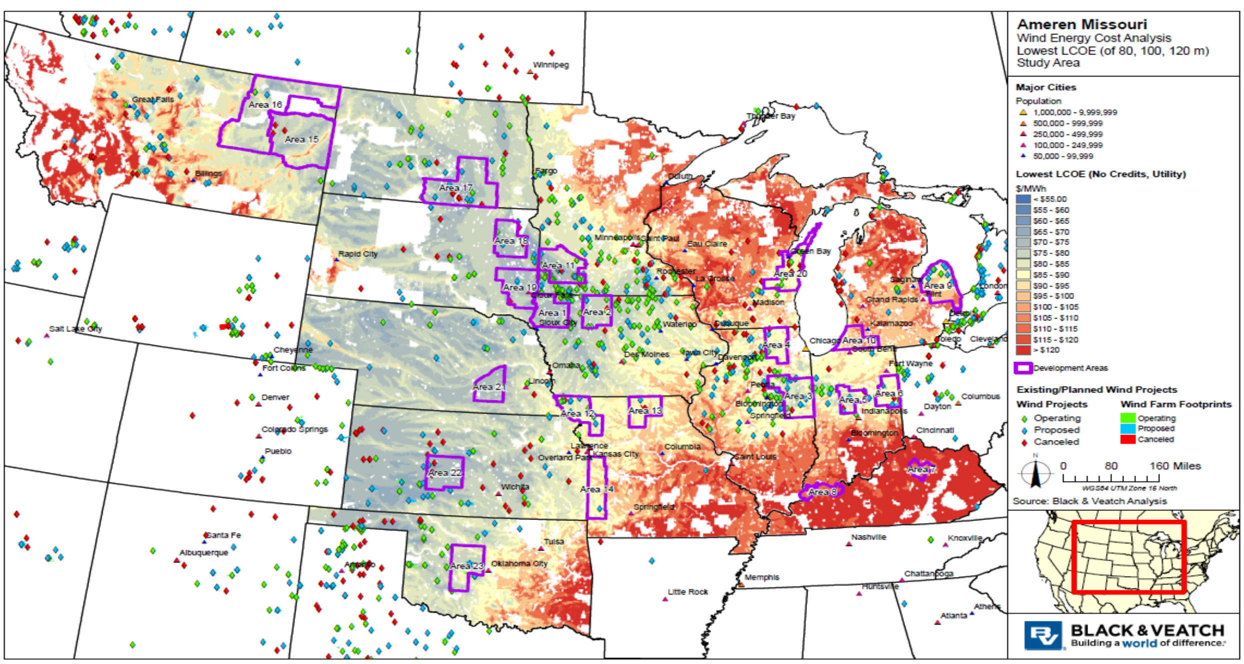


Table 6.16 Priority Development Areas, 80 Meter Results

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

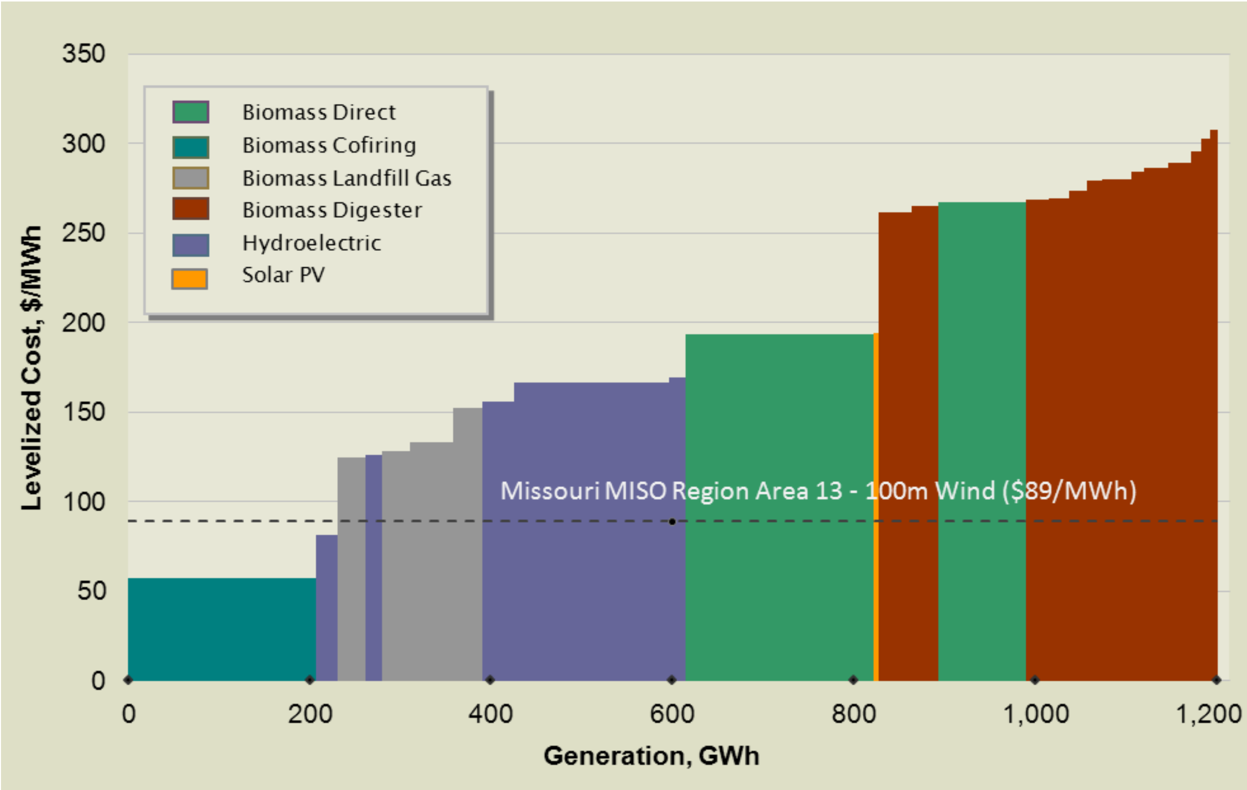
6.2.7 Renewable Supply

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.

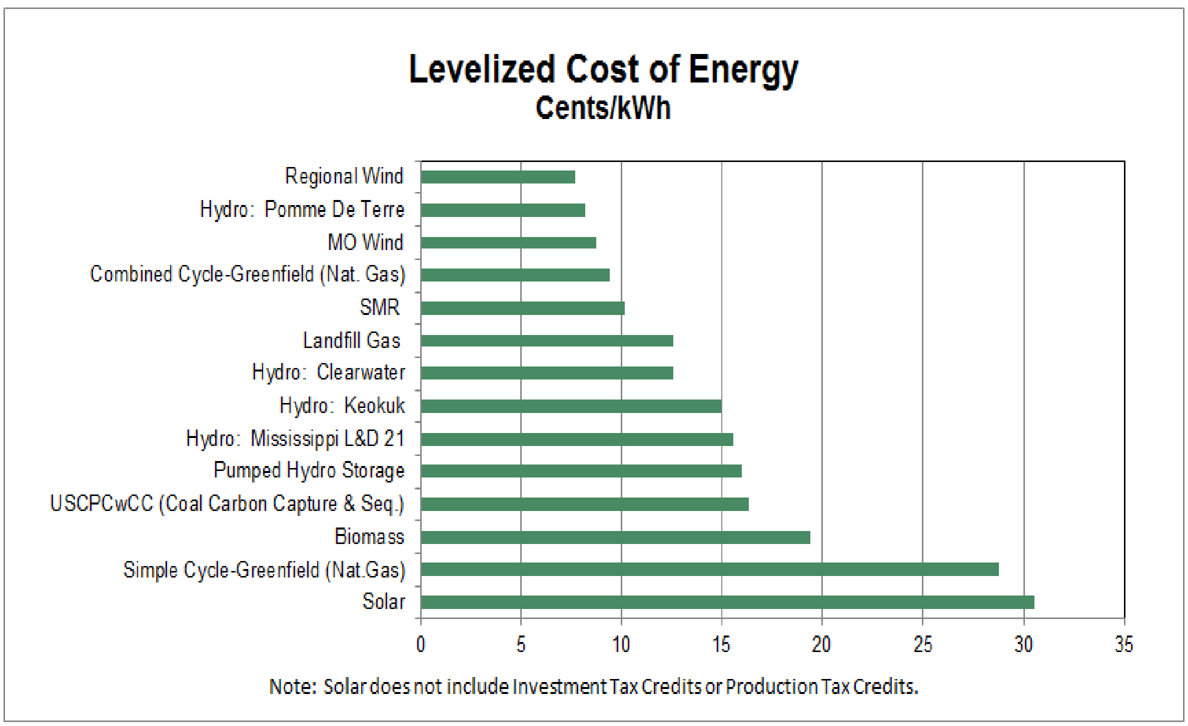
6.4 Power Purchase Agreements

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



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