characteristics were identified that may make the technology particularly appropriate as a contingency option under extreme outcomes.[12]

4.2 Preliminary Screening Analysis

Preliminary Screening Methodology

After each evaluated option was characterized, each was subjected to a preliminary screening analysis. The preliminary screening analysis provided an initial ranking of the technologies. A scoring methodology was developed to compare the different options within their fuel group by an overall weighted score. This score was developed for each option by comparing the following categories: levelized cost of energy, environmental cost, risk reduction, planning flexibility, and operability. Criteria within those categories were established, and numerical scores were assigned on the basis of the differentiating qualitative technology characteristics. Criteria were established on the basis of Black & Veatch's experience with consideration of Ameren Missouri's known planning requirements. Categories and criteria, along with their assigned weightings, are presented in Table 4.B.7.[13]

[12] 4 CSR 240-22.040(1)(J); 4 CSR 240-22.040(1)(K)4; 4 CSR 240-22.040(1)(L)
[13] 4 CSR 240-22.040(2)

Table 4.B.7 Scoring Criteria

Category/Criteria	Category/Criteria Weighting	Scoring Basis Guidelines
Utility Cost	**35**	
Levelized cost of energy	90	100 - Lower 5 percentile. 90 to 10 - 5 to 95 percentile, linearly scaled. 0 - Upper 5 percentile.
Specificity of location	10	100 - Within Ameren Missouri service territory. 50 - Within MISO 0 - Outside MISO
Environmental Cost	**20**	
Currently meets regulated emissions limits	60	100 - Produces no emissions. 85 - Ability to meet emissions limits. 0 - Inability to meet emissions limits.
Potential for future addition of more stringent control technologies and level of control	40	100 - Would not require any future controls for any major pollutants. 75 - May require controls for 2 major pollutants. 50 - May require controls for 3 major pollutants. 25 - May require controls for 4 major pollutants. 0 - May require controls for 5 or more major pollutants.
Risk Reduction	**15**	
Technology status	60	100 - Commercially proven. 50 - Demonstration. 25 - Developmental with positive trend. 0 - Developmental with negative trend.
Constructability	20	100 - Less labor, material and equipment risk. 50 - Moderate labor, material & equipment risk. 25 - More labor, material and equipment availability risk.
Safety training requirements	20	100 - Minimal requirement & hazards. 50 - Industry standard for baseload generation in safety training and hazards. 0 - Unique requirements and/or hazards.
Planning Flexibility	**15**	
Permitting	10	100 - Less extensive permitting. 50 - Moderate permitting. 25 - More extensive permitting.
Schedule Duration	10	100 - Lower 5 percentile. 90 to 10 - 5 to 95 percentile, linearly scaled. 0 - Upper 5 percentile.
Fuel Flexibility	25	100 - No fuel required. 50 - Multiple fuels, multiple sources. 25 - Multiple fuels and single source or single fuel and multiple sources. 0 - Single fuel, single source.
Scalability/Modularity/Resource Constrained	20	100 - Has no constraints. 75 - Has one constraint. 25 - Has two constraints. 0 - Is constrained by scalability, modularity, and resource availability.
Transmission Complexity	15	100 - Requires less redundancy, less planning. 50 - Require more redundancy, more planning.
Construction Schedule and Budget Risk	20	100 - Cost or schedule uncertainty. 75 - Cost and schedule uncertainty. 50 - Cost and schedule uncertainty with limited industry experience. 25 - Major cost and schedule uncertainty. 0 - Major cost and schedule uncertainty with limited industry experience.
Operability	**15**	
Availability	50	100 - Equivalent Availability factor ≥ 85% 50 - Equivalent Availability factor ≤ 85%
Technical Operability Training	15	100 - Minimal technical operability management (TOM). 50 - Moderate TOM 25 - Moderate TOM and advanced technology. 0 - Unique experience and management requirements for operation.
Load-Following/VAR Support	35	100 - Load-following and reactive power support capabilities. 50 - Load-following or reactive power support capabilities. 25 - Moderate load-following or reactive power support capabilities. 0 - Inability or constraints to load-following and reactive power support capabilies.

Risk Reduction – The scoring of the various options took the amount of risk associated with development and operations into account. An option's commercial status, constructability, and potential hazards were all evaluated.

Planning Flexibility – The time required to construct a resource option, the fuels an option could burn to produce electricity, and Ameren Missouri's ability to properly plan and integrate an option into its current service network were evaluated for this category.

Operability – An option's availability, load-following capability, and complexity of operation were reviewed and scored accordingly.

Environmental Cost[14] – A resource option's ability to meet current and potential future environmental regulations was incorporated into the ranking process. Emissions constituents considered for this category include, but are not limited to, CO_2, particulate matter, sulfur oxides (SO_x), NO_x, Hg, and CO. A schedule of emission costs used in the utility cost estimates for screening is presented in Table 4.B.8.

Table 4.B.8 Emissions Costs and Escalation Rates

	SO2	NOx	CO2
2009 $/ton	$25.59	$430.82	$17.17
Escalation	3.00%	3.00%	7.45%
Source	Chicago Climate Fund Exchange - issued 4/27/09		CRA Study 6/2/09

It was assumed that new resources would be required to meet more stringent environmental regulations and, therefore, would not incur any additional mitigation costs. For example, any new coal unit would include a scrubber for SO_2, an SCR for NO_x, activated carbon injection for mercury, and in some cases carbon capture and compression technology. Also, new natural gas units are assumed to include an SCR for NO_x control.

The scenarios described in Chapter 2 include alternative carbon regulation regimes, including: 'Cap-and-Trade', 'Federal Energy Bill', and 'Moderate EPA Regulation', with 33%, 57% and 10% probabilities, respectively, assigned in the probability tree. CAIR and CAMR were modeled in the scenarios developed in Chapter 2 for SO_2, NO_x, and Mercury regulations. It was assumed that new units would require Mercury reductions of 60% by 2015 and 90% by 2020. As described in Chapter 2, the NO_x and SO_2 prices vary by scenarios as they are sensitive to carbon policy and other aspects of the scenarios. All candidate resource options will be evaluated against the scenarios developed in Chapter 2.

[14] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(B)1; 4 CSR 240-22.040(2)(B)2; 4 CSR 240-22.040(2)(B)3; 4 CSR 240-22.040(2)(B)4; 4 CSR 240-22.040(9)(D)

At this point in the analysis Ameren Missouri is not screening any of its existing resources. However, Chapter 8 describes two additional environmental scenarios to better characterize the effects of more stringent environmental regulations on existing Ameren Missouri generation resources, namely its coal assets. Furthermore, those additional environmental scenarios facilitate the retirement analysis of Meramec plant.

Levelized Cost of Energy – One of the more significant criteria in the scoring was the levelized cost of energy (LCOE). Financial factors, such as fuel costs, tax life, economic life, escalation rates, present worth discount rate (PWDR), levelized fixed charge rate (LFCR) that were used in the LCOE estimates in the screening in addition to other costs presented earlier are listed in Table 4.B.9 and Table 4.B.10.

Table 4.B.9 Fuel Prices for LCOE Estimates

Location	Meramec/ Rush	Meramec/ Rush	Greenfield	Greenfield	Greenfield
Type	PRB Coal	IL Coal	PRB Coal	IL Coal	Natural Gas
2009 $/MMBtu	$2.10	$2.86	$2.47	$3.03	$6.09
Escalation	3.81%	3.21%	3.84%	3.26%	2.71%
Source	RI Scrubber Study/2009-2013 Fuel Budget				AFS Nat Gas Forecast 4/28/09

Table 4.B.10 Financial Inputs for LCOE Estimates

Technology	Tax Life Years	Economic Life Years	LFCR Percent	PWDR Percent
PC	20	40	11.83	7.67
CFB	20	40	11.83	7.67
IGCC	20	30	12.42	7.67
Gas Fired Boiler	20	40	12.42	7.67
Simple Cycle	15	30	12.03	7.67
Combined Cycle	20	30	12.42	7.67
Fuel Cells	15	20	13.62	7.67
Gas Reciprocating	15	30	12.03	7.67

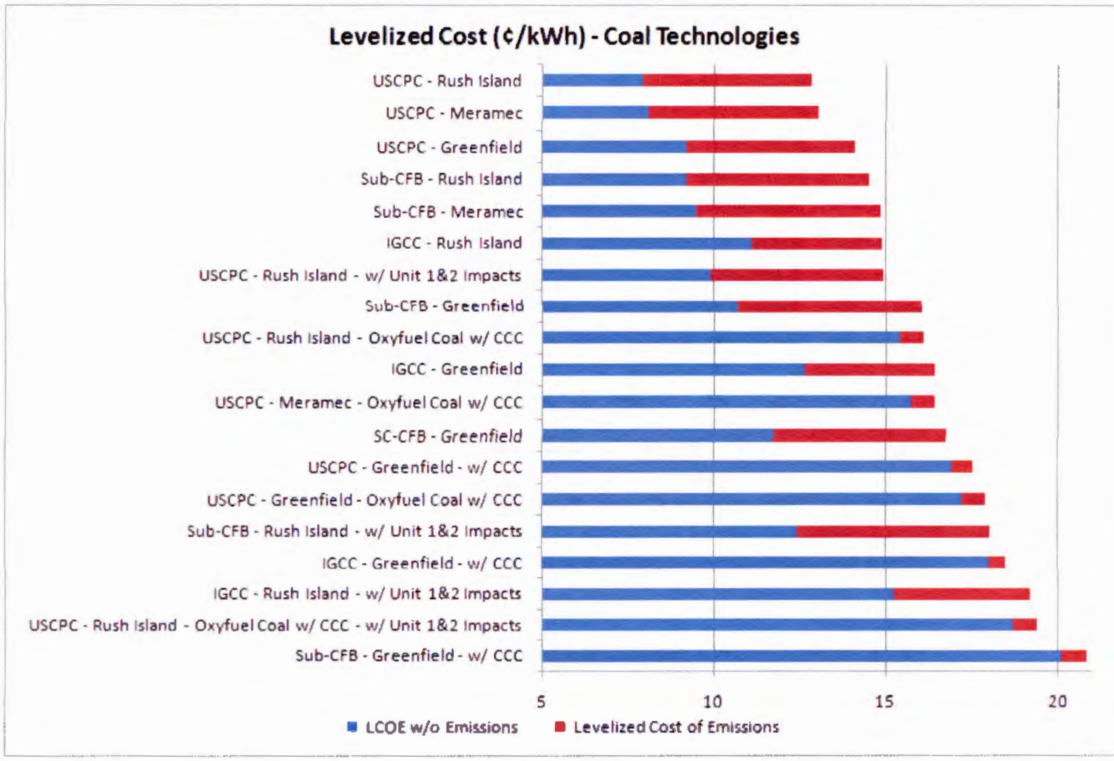
Annual costs for the LCOE estimates include levelized annual capital cost, fixed and variable O&M, fuel cost, and emissions allowances if applicable; LCOE estimates were developed in three different ways: without emission costs, with emissions costs for SO_2 and NO_x, and with emissions costs for SO_2, NO_x and CO_2.[15]

[15] 4 CSR 240-22.040(2)(A)

Preliminary Screening Results

The levelized costs of energy and overall scorings of the evaluated options are presented in Table 4.B.20a, Table 4.B.20b, Table 4.B.21a and Table 4.B.21b. All levelized costs of energy and overall scorings are presented with and without SO_2, NO_x, and CO_2 price forecasts included. The following figures show the LCOE and total screening scores.[16]

Figure 4.B.1 LCOE for Coal Options[17]



[16] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(B)1
[17] 4 CSR 240-22.040(2)

Figure 4.B.2 LCOE for Gas Options[18]

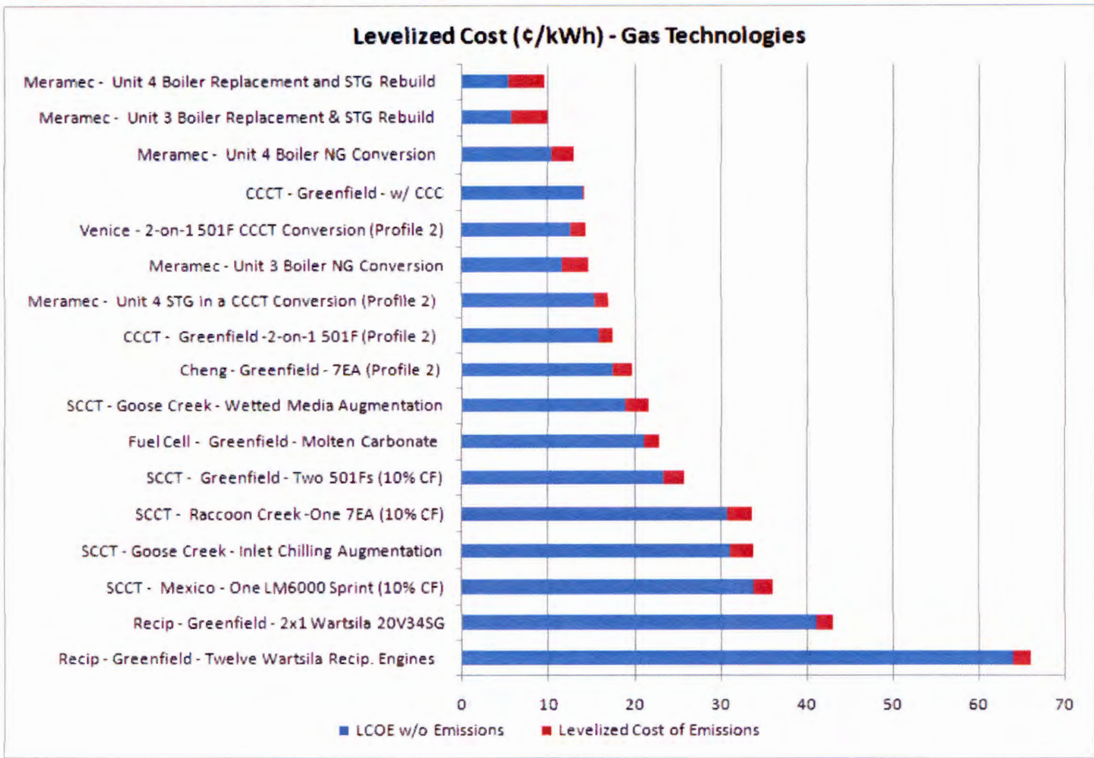
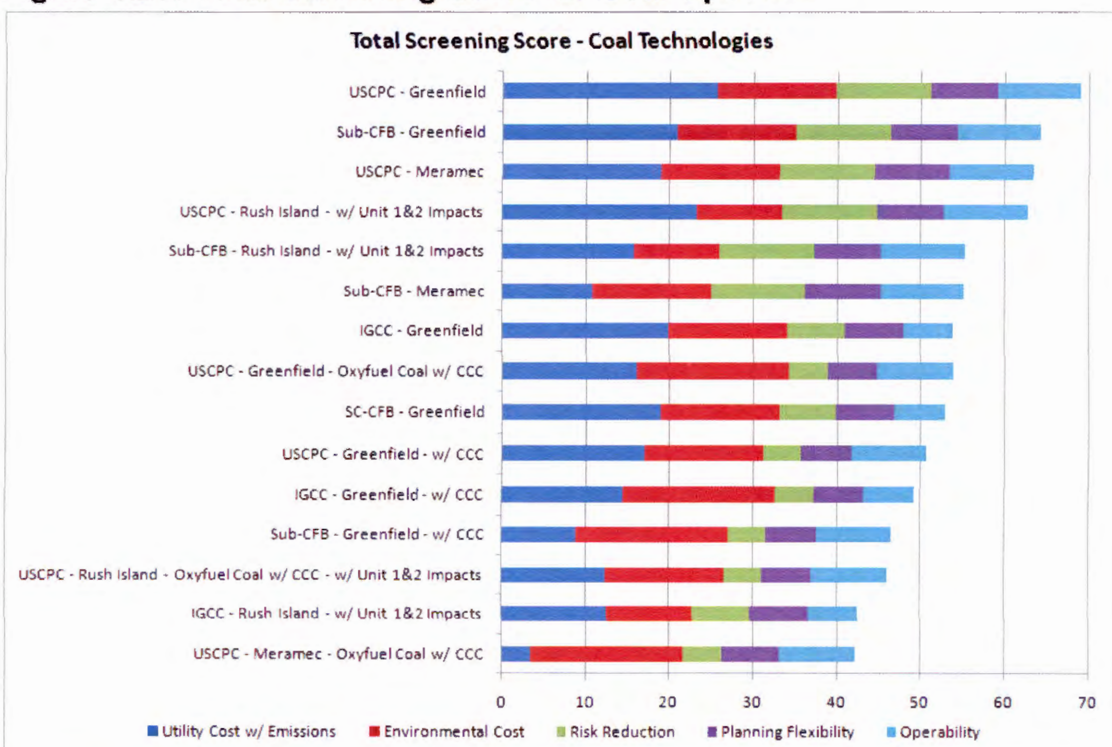
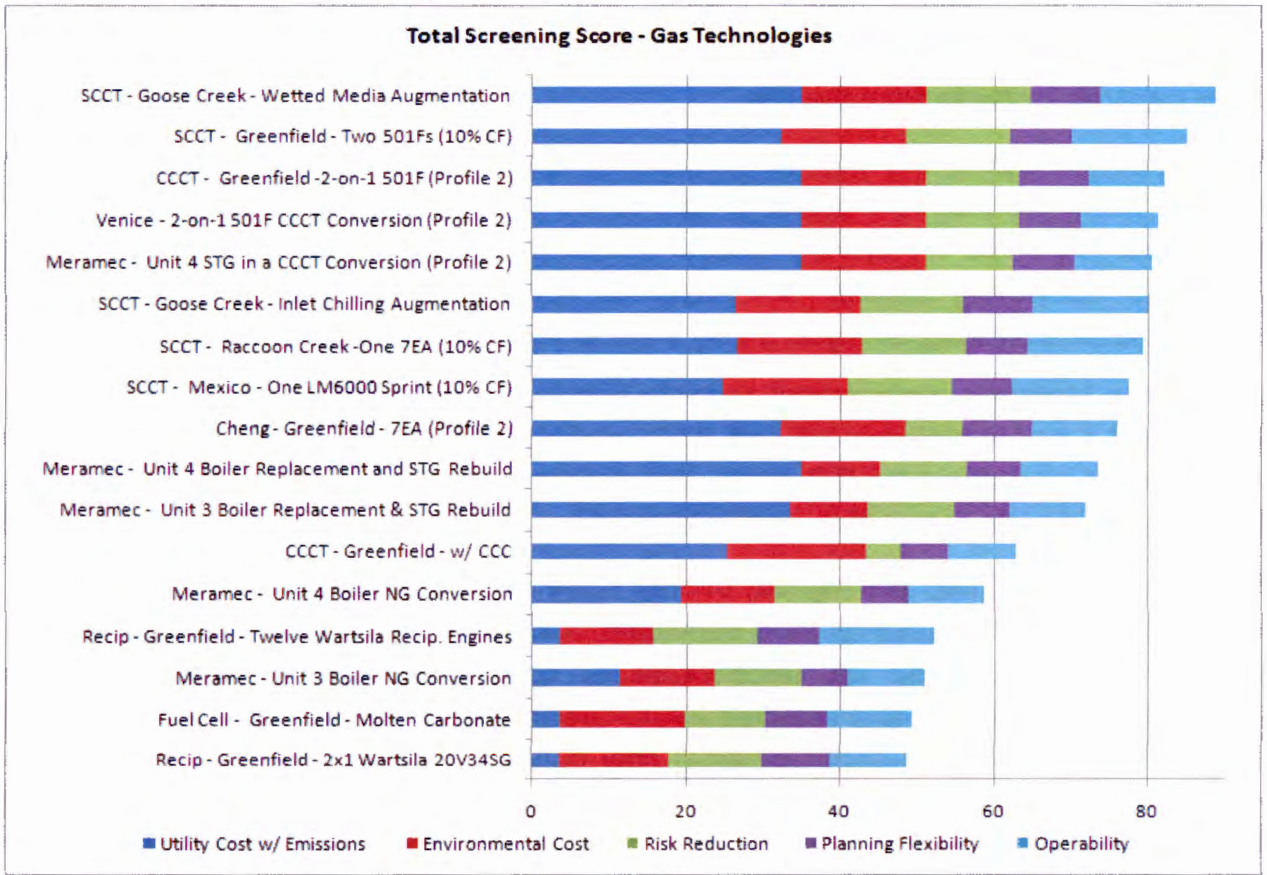


Figure 4.B.3 Total Screening Score for Coal Options[19]



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

Figure 4.B.4 Total Screening Score for Gas Options[20]



Based on the scoring results, Ameren Missouri selected 10 options to carry forward[21].

The 2-on-1 501F based combined cycle options scored highest among the new capacity options with intermediate dispatch load profiles. The Cheng cycle option ranked high in large part due to its comparatively low costs of electricity. However, operational and project development risks pushed their overall scores below that of the combined cycle. The peaking option rankings favored the larger, 501F combustion turbines over the 7EA combustion turbine, with the GE LM6000 and Wartsila 20V34SG reciprocating engines rounding out the list.

The Venice combined cycle conversion will replace CTG Units 3 and 4 from a dispatch perspective. Modeled as a 2-on-1 combined cycle, the Venice combined cycle conversion option scored well and appears to offer a low total cost of energy. However, the prerequisite retirement of Venice Unit 3 and 4 simple cycle units should weigh heavily when considering other expansion.

As with the Venice combined cycle conversion, the repowering of existing units or the addition of new units at Meramec will displace existing capacity. The repowering of the

[20] 4 CSR 240-22.040(2)(C)
[21] 4 CSR 240-22.040(2)(C); 4 CSR 240-22.040(9)(A)3

Unit 4 STG in a combined cycle or the addition of a new coal unit at Meramec is assumed to require the retirement of existing Units 1 through 4. Whether the option is to repower, build a new unit, or rebuild existing units, the result will not necessarily result in a net capacity increase from the site.

Environmental regulations and permitting strategies that are currently valid will likely change within the next few years. In light of the current regulatory landscape, natural gas fueled Meramec repowering options should be given preference over coal fueled Meramec repowering options. The Meramec options would be subject to extensive environmental permitting analysis if they were to be considered for further development.

Among the Meramec replacement capacity baseload dispatched options, the Meramec Unit 3 and 4 boiler replacement and STG rebuild options received the highest scores except when accounting for CO_2 costs. When accounting for CO_2 costs, the Unit 4 STG in a combined cycle conversion ranked highest.

USCPC-Greenfield had the highest overall score among the coal technology options, and therefore, was passed on as a candidate coal option. The Ameren Missouri team also wanted to include an unconventional coal technology in addition to the conventional technology and selected IGCC-Greenfield for further characterization as it was the highest scoring unconventional coal option. Technologies that incorporated carbon capture consistently lagged behind their non-carbon capture counterparts even when accounting for CO_2 costs. However, both USCPC and IGCC with carbon capture were also passed on to the next step in the analysis with their non-carbon capture counterparts. All other coal resource options were eliminated from further analysis to keep the options to a manageable size as the four technologies selected would be more than enough to represent coal supply side technologies.

Power augmentation options appear to score better than the other natural gas technologies; however, since the capacity addition is much smaller compared to the others, they were eliminated from further analysis for the purposes of this IRP. Furthermore, the natural gas resource options that had an overall score lower than that of the aero-derivative simple cycle (GE LM6000 SPRINT) were not considered for further analysis.

4.3 Candidate Options

Using the preliminary screening results as a tool, Ameren Missouri selected 10 technologies to be characterized further for modeling and planning efforts. Table 4.B.11 presents a listing of the preliminary candidate options.

Table 4.B.11 Preliminary Candidate Options[22]

Fuel Type	Base Load Technologies
Coal	Greenfield - USCPC
Coal	Greenfield - USCPC w/Carbon Capture
Coal	Greenfield - IGCC
Coal	Greenfield - IGCC w/Carbon Capture
	Intermediate Load Technologies
Gas	Venice - 2-on-1 501F Combined Cycle Conversion
Gas	Greenfield - 2-on-1 501F Combined Cycle
Gas	Meramec - Unit 4 STG in a Combined Cycle Conversion
	Peaking Load Technologies
Gas	Greenfield - Two Siemens 501Fs with SCR
Gas	Mexico - One GE LM6000 SPRINT with SCR
Gas	Raccoon Creek - One GE 7EA with SCR

[22] 4 CSR 240-22.040(2)(C); 4 CSR 240-22.040(9)(A)2

4.4 Supporting Tables

Table 4.B.12 Coal Options – Capacity and Performance

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Gross Plant Output, MW (20 F)	Full Load Auxiliary, MW (20 F)	Full Load Net Plant Output, MW (20 F)	Full Load Net Plant Heat Rate HHV, Btu/kWh (20 F)	Full Load Gross Plant Output, MW (95 F)	Full Load Auxiliary, MW (95 F)	Full Load Net Plant Output, MW (95 F)	Full Load Net Plant Heat Rate HHV, Btu/kWh (95 F)	Assumed Annual Capacity Factor, percentage	Forced Outage Rate, percentage
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	Sub-CFB	602	145	457	13,200	598	145	453	13,300	85%	11%
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	USCPC	860	174	686	12,200	852	173	679	12,300	85%	8%
CCC - Greenfield -IGCC Pre Combustion	Coal	Baseload	IGCC	722	214	508	12,000	713	220	493	11,800	80%	13%
CCC - Greenfield - Oxyfuel Coal	Coal	Baseload	USCPC	971	345	626	13,400	963	343	620	13,500	85%	8%
CCC - Meramec - Oxyfuel Coal	Coal	Baseload	USCPC	971	345	626	13,400	963	343	620	13,500	85%	8%
CCC - Rush Island - Oxyfuel Coal	Coal	Baseload	USCPC	971	345	626	13,400	963	343	620	13,500	85%	8%
CCC - Rush Island - Oxyfuel -Inc Unit 1 & 2 Impacts	Coal	Baseload	USCPC	971	377	594	14,100	963	375	588	14,200	85%	8%
Greenfield - Single Unit	Coal	Baseload	IGCC	727	148	579	9,060	718	156	562	9,010	80%	13%
Greenfield - Single Unit	Coal	Baseload	SC-CFB	684	79	605	9,500	679	79	600	9,600	80%	11%
Greenfield - Single Unit	Coal	Baseload	Sub-CFB	676	71	605	9,950	671	71	600	10,030	85%	11%
Greenfield - Single Unit	Coal	Baseload	USCPC	971	63	908	9,220	963	63	900	9,300	85%	8%
Meramec - New Unit	Coal	Baseload	Sub-CFB	676	71	605	9,950	671	71	600	10,030	85%	11%
Meramec - New Unit	Coal	Baseload	USCPC	971	63	908	9,220	963	63	900	9,300	85%	8%
Rush Island - New Unit	Coal	Baseload	IGCC	727	148	579	9,060	718	156	562	9,010	80%	13%
Rush Island - New Unit	Coal	Baseload	Sub-CFB	676	71	605	9,950	671	71	600	10,030	85%	11%
Rush Island - New Unit	Coal	Baseload	USCPC	971	63	908	9,220	963	63	900	9,300	85%	8%
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	IGCC	727	180	547	9,590	718	188	530	9,550	80%	13%
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	Sub-CFB	676	103	573	10,500	671	103	568	10,590	85%	11%
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	USCPC	971	95	876	9,550	963	95	868	9,600	85%	8%

Table 4.B.13 Gas Options – Capacity and Performance

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Gross Plant Output, MW (20 F)	Full Load Auxiliary, MW (20 F)	Full Load Net Plant Output, MW (20 F)	Full Load Net Plant Heat Rate HHV, Btu/kWh (20 F)	Full Load Gross Plant Output, MW (95 F)	Full Load Auxiliary, MW (95 F)	Full Load Net Plant Output, MW (95 F)	Full Load Net Plant Heat Rate HHV, Btu/kWh (95 F)	Assumed Annual Capacity Factor, percentage	Forced Outage Rate, percentage
CCC - Greenfield - CCCT Amine-Based Post Combustion	Gas	Baseload	CCCT	587	73	514	8,400	562	72	490	8,900	85%	2%
Goose Creek -Inlet Chilling Augmentation	Gas	Peaking	SCCT	N/A	N/A	N/A	N/A	78	24	54	12,170	5%	4%
Goose Creek -Wetted Media Augmentation	Gas	Peaking	SCCT	N/A	N/A	N/A	N/A	18	0	18	12,170	5%	4%
Greenfield - 2-on-1 501F	Gas	Baseload	CCCT	644	15.0	629	6,860	617	17.2	600	7,230	85%	2%
Greenfield - 2x1 Wartsila 20V34SG (Profile 1)	Gas	Intermediate	Recip	18.3	0.57	17.8	8,100	18.3	0.57	17.8	8,100	12%	2%
Greenfield - Molten Carbonate	Gas	Intermediate	Fuel Cell	N/A	N/A	100	8,450	N/A	N/A	100	8,450	85%	2%
Greenfield - Two 501Fs (10% CF)	Gas	Peaking	SCCT	441	11.4	429	10,170	356	10.0	346	10,700	10%	5%
Greenfield - Two 501Fs (5% CF)	Gas	Peaking	SCCT	443	7.1	436	10,020	358	5.7	352	10,530	5%	5%
Greenfield -2-on-1 501F (Profile 2)	Gas	Intermediate	CCCT	644	15.0	629	6,860	617	17.2	600	7,230	21%	2%
Meramec - 2-on-1 501F	Gas	Baseload	CCCT	644	15.0	629	6,860	617	17.2	600	7,230	85%	2%
Mexico - One LM6000 Sprint (10% CF)	Gas	Peaking	SCCT	48.3	1.4	46.9	9,260	40.5	1.2	39.3	9,780	10%	6%
Mexico - One LM6000 Sprint (5% CF)	Gas	Peaking	SCCT	48.5	1.2	47.3	9,180	40.7	1.0	39.7	9,690	5%	6%
Raccoon Creek - One 7EA (5% CF)	Gas	Peaking	SCCT	93.6	1.4	92.2	11,560	75.0	1.1	73.9	12,170	5%	4%
Raccoon Creek -One 7EA (10% CF)	Gas	Peaking	SCCT	93.2	1.8	91.4	11,660	74.7	1.5	73.2	12,280	10%	4%
Meramec Unit 3 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	300	21	279	9,500	297	21	276	9,600	85%	7%
Meramec Unit 4 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	356	22	335	11,100	353	22	332	11,200	85%	8%
Meramec Unit 4 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	396	24	372	9,400	393	24	369	9,500	85%	7%
Meramec Unit 4 STG in a CCCT Conversion	Gas	Baseload	CCCT	961	22	940	6,890	855	21	834	7,090	85%	4%
Meramec Unit 4 STG in a CCCT Conversion (Profile 2)	Gas	Intermediate	CCCT	961	22	940	6,890	855	21	834	7,090	21%	4%
Venice - 2-on-1 501F Conversion	Gas	Baseload	CCCT	179	8.6	171	7,180	264	10.0	254	7,300	85%	2%
Venice - 2-on-1 501F Conversion (Profile 1)	Gas	Intermediate	CCCT	179	8.6	171	7,180	264	10.0	254	7,300	12%	2%
Venice - 2-on-1 501F Conversion (Profile 2)	Gas	Intermediate	CCCT	179	8.6	171	7,180	264	10.0	254	7,300	21%	2%
Greenfield - 7EA (Profile 2)	Gas	Intermediate	Cheng	122	2.4	119	9,200	98	2.0	96	9,700	21%	6%
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	Recip	101.2	2.2	99.0	8,740	101.2	2.2	99.0	8,740	5%	4%
Unit 3 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	256	16	239	12,400	253	16	237	12,500	85%	8%

Table 4.B.14 Coal Options – Cost Estimates[23]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	EPC Capital Cost, $1,000	EPC Capital Cost, $/kW	Total Project Cost - Includes Assumed Owners Cost, $1,000	Total Project Cost - Includes Assumed Owners Cost, $/kW	First Year Fixed O&M Cost, $1,000/yr	First Year Fixed O&M Cost, $/kW-yr	First Year Variable O&M Cost, $1,000/yr	First Year Variable O&M Cost, $/MWh	First Year Total O&M Cost, $/MWh	First Year Fuel Cost, $/MBtu	Owner's Cost, percent	AFUDC Cost, percent	Total Owner's Cost, percent
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	USCPC	679	3,230,000	4,760	4,333,100	6,380	25,344	37.3	50,054	9.9	14.9	2.47	12.4%	22%	34%
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	Sub-CFB	453	2,550,000	5,630	3,444,300	7,600	22,980	50.7	40,713	12.1	18.9	2.47	12.5%	23%	35%
CCC - Greenfield -IGCC Pre Combustion	Coal	Baseload	IGCC	493	2,170,000	4,400	3,147,200	6,380	22,481	45.6	36,622	10.6	17.11	2.47	24%	21%	45%
CCC - Greenfield - Oxyfuel Coal	Coal	Baseload	USCPC	620	2,900,000	4,680	3,931,300	6,340	23,628	38.1	42,629	9.2	14.4	2.47	13.8%	22%	36%
CCC - Meramec - Oxyfuel Coal	Coal	Baseload	USCPC	620	2,810,000	4,530	3,649,800	5,890	23,650	38.1	42,629	9.2	14.4	2.10	8.1%	22%	30%
CCC - Rush Island - Oxyfuel Coal	Coal	Baseload	USCPC	620	2,780,000	4,480	3,583,200	5,780	18,610	30.0	42,629	9.2	13.3	2.10	7.1%	22%	29%
CCC - Rush Island - Oxyfuel -Inc Unit 1 & 2 Impacts	Coal	Baseload	USCPC	588	3,420,000	5,810	4,362,500	7,420	23,430	39.8	51,851	11.8	17.2	2.10	5.8%	22%	28%
Greenfield - Single Unit	Coal	Baseload	IGCC	562	1,670,000	2,970	2,485,100	4,420	18,321	32.6	24,025	6.10	10.75	2.47	30%	19%	49%
Greenfield - Single Unit	Coal	Baseload	SC-CFB	600	1,590,000	2,650	2,389,400	3,980	17,699	29.5	16,504	3.93	8.13	2.47	30%	20%	50%
Greenfield - Single Unit	Coal	Baseload	Sub-CFB	600	1,500,000	2,500	2,104,200	3,510	17,520	29.2	17,088	3.82	7.75	2.47	20%	20%	40%
Greenfield - Single Unit	Coal	Baseload	USCPC	900	1,900,000	2,110	2,651,300	2,950	18,428	20.5	20,129	3.00	5.75	2.47	20%	20%	40%
Meramec - New Unit	Coal	Baseload	Sub-CFB	600	1,430,000	2,380	1,884,400	3,140	17,520	29.2	17,088	3.82	7.75	2.10	11.5%	20%	32%
Meramec - New Unit	Coal	Baseload	USCPC	900	1,810,000	2,010	2,371,800	2,640	18,450	20.5	20,129	3.00	5.76	2.10	11.5%	20%	31%
Rush Island - New Unit	Coal	Baseload	IGCC	562	1,600,000	2,850	2,220,900	3,950	13,332	23.7	24,025	6.10	9.49	2.10	20%	19%	39%
Rush Island - New Unit	Coal	Baseload	Sub-CFB	600	1,420,000	2,370	1,850,000	3,080	12,540	20.9	17,088	3.82	6.63	2.10	10%	20%	30%
Rush Island - New Unit	Coal	Baseload	USCPC	900	1,780,000	1,980	2,305,800	2,560	13,410	14.9	20,129	3.00	5.00	2.10	10%	20%	30%
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	IGCC	530	2,240,000	4,220	3,109,300	5,860	18,152	34.2	33,247	8.95	13.83	2.10	20%	19%	39%
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	Sub-CFB	568	2,060,000	3,630	2,619,700	4,610	17,360	30.6	26,310	6.22	10.3	2.10	6.9%	20%	27%
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	USCPC	868	2,420,000	2,790	3,070,900	3,540	18,230	21.0	29,351	4.54	7.38	2.10	7.4%	20%	27%

[23] 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(F); 4 CSR 240-22.040(1)(G); 4 CSR 240-22.040(8)(B); 4 CSR 240-22.040(8)(C)

Table 4.B.15 Gas Options – Cost Estimates[24]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	EPC Capital Cost, $1,000	EPC Capital Cost, $/kW	Total Project Cost - Includes Assumed Owners Cost, $1,000	Total Project Cost - Includes Assumed Owners Cost, $/kW	First Year Fixed O&M Cost, $1,000/yr	First Year Fixed O&M Cost, $/kW-yr	First Year Variable O&M Cost, $1,000/yr	First Year Variable O&M Cost, $/MWh	First Year Total O&M Cost, $/MWh	First Year Fuel Cost, $/MBtu	Owner's Cost, percent	AFUDC Cost, percent	Total Owner's Cost, percent
CCC - Greenfield - CCCT Amine-Based Post Combustion	Gas	Baseload	CCCT	490	1,310,000	2,670	1,616,500	3,300	9,612	19.6	28,031	7.68	10.32	6.09	7.5%	16%	23%
Goose Creek -Inlet Chilling Augmentation	Gas	Peaking	SCCT	54	N/A	N/A	39,400	730	220	4.1	0	0	9.30	6.09	25%	3%	28%
Goose Creek -Wetted Media Augmentation	Gas	Peaking	SCCT	18	N/A	N/A	2,700	150	286	15.9	0	0	36.23	6.09	68%	2%	70%
Greenfield - 2-on-1 501F	Gas	Baseload	CCCT	600	650,000	1,080	808,600	1,350	6,180	10.3	13,181	2.95	4.33	6.09	12%	12%	24%
Greenfield - 2x1 Wartsila 20V34SG (Profile 1)	Gas	Intermediate	Recip	17.8	32,100	1,810	44,400	2,500	631	35.5	141	7.63	41.78	6.09	26%	12%	38%
Greenfield - Molten Carbonate	Gas	Intermediate	Fuel Cell	100	500,000	5,000	626,400	6,260	0	0	26,061	35.0	35.0	6.09	5%	20%	25%
Greenfield - Two 501Fs (10% CF)	Gas	Peaking	SCCT	346	244,000	700	301,700	870	2,386	6.89	3,891	12.8	20.69	6.09	15%	9%	24%
Greenfield - Two 501Fs (5% CF)	Gas	Peaking	SCCT	352	223,000	630	278,000	790	2,425	6.89	2,345	15.2	30.94	6.09	16%	9%	25%
Greenfield -2-on-1 501F (Profile 2)	Gas	Intermediate	SCCT	600	650,000	1,080	808,600	1,350	4,225	7.04	4,094	3.65	7.41	6.09	12%	12%	24%
Meramec - 2-on-1 501F	Gas	Baseload	SC-CFB	600	618,000	1,030	886,200	1,480	4,306	7.18	13,181	2.95	3.91	6.09	31%	12%	43%
Mexico - One LM6000 Sprint (10% CF)	Gas	Peaking	SCCT	39.3	45,400	1,150	59,800	1,520	1,084	27.6	224	6.50	37.95	6.09	23%	9%	32%
Mexico - One LM6000 Sprint (5% CF)	Gas	Peaking	SCCT	39.7	38,500	970	51,800	1,300	1,094	27.6	101	5.82	68.73	6.09	26%	9%	35%
Raccoon Creek - One 7EA (5% CF)	Gas	Peaking	SCCT	73.9	60,400	820	77,700	1,050	1,113	15.1	564	17.4	51.80	6.09	20%	9%	29%
Raccoon Creek -One 7EA (10% CF)	Gas	Peaking	SCCT	73.2	69,200	950	88,300	1,210	1,103	15.1	977	15.2	32.42	6.09	19%	9%	28%
Meramec Unit 3 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	276	290,000	1,050	344,400	1,250	9,502	34.4	1,810	0.88	5.50	2.10	15%	4%	19%
Meramec Unit 4 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	332	37,000	110	171,400	520	6,635	20.0	1,284	0.52	3.21	6.09	360%	3%	363%
Meramec Unit 4 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	369	362,000	980	429,900	1,170	9,657	26.2	2,278	0.83	4.35	2.10	15%	4%	19%
Meramec Unit 4 STG in a CCCT Conversion	Gas	Baseload	CCCT	834	742,000	890	1,098,600	1,320	7,391	8.86	14,063	2.26	3.45	6.09	36%	12%	48%
Meramec Unit 4 STG in a CCCT Conversion (Profile 2)	Gas	Intermediate	CCCT	834	742,000	890	1,098,600	1,320	5,314	6.37	4,740	3.04	6.44	6.09	36%	12%	48%
Venice - 2-on-1 501F Conversion	Gas	Baseload	CCCT	254	374,000	1,470	521,500	2,060	5,672	22.35	12,662	6.70	9.70	6.09	26%	13%	39%
Venice - 2-on-1 501F Conversion (Profile 1)	Gas	Intermediate	CCCT	254	374,000	1,470	521,500	2,060	4,077	16.07	4,457	16.89	32.3	6.09	26%	13%	39%
Venice - 2-on-1 501F Conversion (Profile 2)	Gas	Intermediate	CCCT	254	374,000	1,470	521,500	2,060	4,077	16.07	3,905	8.23	16.8	6.09	26%	13%	39%
Greenfield - 7EA (Profile 2)	Gas	Intermediate	Cheng	98	81,000	850	104,800	1,100	1,439	15.1	1,929	10.8	18.84	6.09	17%	12%	29%
Greenfield - Twelve Wartsila Recip Engines	Gas	Peaking	Recip	99.0	139,000	1,400	171,900	1,740	2,590	26.2	355	8.18	67.91	6.09	14%	10%	24%
Unit 3 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	237	29,000	120	163,300	690	6,241	26.3	1,007	0.57	4.10	6.09	460%	3%	463%

[24] 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(F); 4 CSR 240-22.040(1)(G); 4 CSR 240-22.040(8)(B); 4 CSR 240-22.040(8)(C)

Table 4.B.16 Coal Options – Commercial Status, Construction Duration and Environmental Characteristics[25]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Fuel Flexibility	Technology Maturity	Permitting & Development, months	NTP to COD, months	NOx, lbm/MBtu	SO2, lbm/MBtu	CO2, lbm/MBtu	CO, lbm/MBtu	PM10, lbm/MBtu	Hg, removal percentage	Water Usage, gal/min
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	USCPC	679	Yes	Developing	24 to 36	64	0.05	0.06	21	0.12	0.012	90%	8,300 to 15,400
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	Sub-CFB	453	Yes	Developing	24 to 36	66	0.08	0.08	21	0.13	0.012	90%	6,200 to 11,500
CCC - Greenfield -IGCC Pre Combustion	Coal	Baseload	IGCC	493	Limited	Developing	24 to 36	62	0.01	0.03	21	0.03	0.011	90%	3,300 to 6,200
CCC - Greenfield - Oxyfuel Coal	Coal	Baseload	USCPC	620	Yes	Developing	24 to 36	64	0.005	0.006	21	0.012	0.0012	90%	6,400 to 11,900
CCC - Meramec - Oxyfuel Coal	Coal	Baseload	USCPC	620	Yes	Developing	24 to 36	64	0.005	0.006	21	0.012	0.0012	90%	6,400 to 11,900
CCC - Rush Island - Oxyfuel Coal	Coal	Baseload	USCPC	620	Yes	Developing	24 to 36	64	0.005	0.006	21	0.012	0.0012	90%	6,400 to 11,900
CCC - Rush Island - Oxyfuel -Inc Unit 1 & 2 Impacts	Coal	Baseload	USCPC	588	Yes	Developing	24 to 36	64	0.005	0.006	21	0.012	0.0012	90%	7,500 to 13,000
Greenfield - Single Unit	Coal	Baseload	IGCC	562	Limited	Developing	24 to 36	56	0.01	0.03	212	0.03	0.011	90%	3,000 to 5,600
Greenfield - Single Unit	Coal	Baseload	SC-CFB	600	Yes	Developing	24 to 36	60	0.08	0.08	212	0.13	0.012	90%	4,800 to 8,900
Greenfield - Single Unit	Coal	Baseload	Sub-CFB	600	Yes	Mature	24 to 36	60	0.08	0.08	212	0.13	0.012	90%	4,800 to 8,900
Greenfield - Single Unit	Coal	Baseload	USCPC	900	Yes	Mature	24 to 36	58	0.05	0.06	212	0.12	0.012	90%	6,400 to 11,900
Meramec - New Unit	Coal	Baseload	Sub-CFB	600	Yes	Mature	24 to 36	60	0.08	0.08	212	0.13	0.012	90%	4,800 to 8,900
Meramec - New Unit	Coal	Baseload	USCPC	900	Yes	Mature	24 to 36	58	0.05	0.06	212	0.12	0.012	90%	6,400 to 11,900
Rush Island - New Unit	Coal	Baseload	IGCC	562	Limited	Developing	24 to 36	56	0.01	0.03	212	0.03	0.011	90%	3,000 to 5,600
Rush Island - New Unit	Coal	Baseload	Sub-CFB	600	Yes	Mature	24 to 36	60	0.08	0.08	212	0.13	0.012	90%	4,800 to 8,900
Rush Island - New Unit	Coal	Baseload	USCPC	900	Yes	Mature	24 to 36	58	0.05	0.06	212	0.12	0.012	90%	6,400 to 11,900
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	IGCC	530	Limited	Developing	24 to 36	56	0.01	0.03	212	0.03	0.011	90%	3,000 to 5,600
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	Sub-CFB	568	Yes	Mature	24 to 36	60	0.08	0.08	212	0.13	0.012	90%	5,900 to 10,000
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	USCPC	868	Yes	Mature	24 to 36	58	0.05	0.06	212	0.12	0.012	90%	7,500 to 13,000

[25] 4 CSR 240-22.040(1)(C); 4 CSR 240-22.040(1)(D); 4 CSR 240-22.040(1)(K)1; 4 CSR 240-22.040(1)(K)3

Table 4.B.17 Gas Options – Commercial Status, Construction Duration and Environmental Characteristics[26]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Fuel Flexibility	Technology Maturity	Permitting & Development, months	NTP to COD, months	NOx, lbm/MBtu	SO2, lbm/MBtu	CO2, lbm/MBtu	CO, lbm/MBtu	PM10, lbm/MBtu	Hg, removal percentage	Water Usage, gal/min
CCC - Greenfield - CCCT Amine-Based Post Combustion	Gas	Baseload	CCCT	490	Yes	Developing	14 to 18	48	0.0092	0.0006	12	0.009	0.0044	0%	3,400 to 6,200
Goose Creek -Inlet Chilling Augmentation	Gas	Peaking	SCCT	54	Yes	Mature	14 to 18	10	0.033	0.0006	117	0.06	0.006	0%	150
Goose Creek -Wetted Media Augmentation	Gas	Peaking	SCCT	18	Yes	Mature	14 to 18	6	0.033	0.0006	117	0.06	0.006	0%	16
Greenfield - 2-on-1 501F	Gas	Baseload	CCCT	600	Yes	Mature	14 to 18	38	0.0092	0.0006	117	0.009	0.0044	0%	2,500 to 4,600
Greenfield - 2x1 Wartsila 20V34SG (Profile 1)	Gas	Intermediate	Recip	17.8	Yes	Mature	14 to 18	38	0.032	0.0006	117	0.57	0.024	0%	10 to 100
Greenfield - Molten Carbonate	Gas	Intermediate	Fuel Cell	100	Limited	Developing	14 to 18	60	0.003	0.000014	136	0.005	0.000003	0%	300 to 1,100
Greenfield - Two 501Fs (10% CF)	Gas	Peaking	SCCT	346	Yes	Mature	14 to 18	27	0.010	0.0006	117	0.009	0.004	0%	25 to 46
Greenfield - Two 501Fs (5% CF)	Gas	Peaking	SCCT	352	Yes	Mature	14 to 18	27	0.033	0.0006	117	0.009	0.003	0%	25 to 46
Greenfield -2-on-1 501F (Profile 2)	Gas	Intermediate	SCCT	600	Yes	Mature	14 to 18	38	0.0092	0.0006	117	0.009	0.0044	0%	2,500 to 4,600
Meramec - 2-on-1 501F	Gas	Baseload	SC-CFB	600	Yes	Mature	14 to 18	38	0.0092	0.0006	117	0.009	0.0044	0%	2,500 to 4,600
Mexico - One LM6000 Sprint (10% CF)	Gas	Peaking	SCCT	39.3	Yes	Mature	14 to 18	27	0.016	0.0006	117	0.12	0.007	0%	15 to 29
Mexico - One LM6000 Sprint (5% CF)	Gas	Peaking	SCCT	39.7	Yes	Mature	14 to 18	27	0.054	0.0006	117	0.12	0.005	0%	15 to 29
Raccoon Creek - One 7EA (5% CF)	Gas	Peaking	SCCT	73.9	Yes	Mature	14 to 18	27	0.033	0.0006	117	0.06	0.006	0%	7 to 14
Raccoon Creek -One 7EA (10% CF)	Gas	Peaking	SCCT	73.2	Yes	Mature	14 to 18	27	0.010	0.0006	117	0.06	0.009	0%	7 to 14
Meramec Unit 3 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	276	Limited	Mature	18 to 24	12	0.18	0.95	212	N/A	N/A	N/A	200 to 400
Meramec Unit 4 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	332	Limited	Mature	18 to 24	10	0.1	0.0006	117	N/A	N/A	N/A	300 to 600
Meramec Unit 4 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	369	Limited	Mature	18 to 24	12	0.18	0.95	212	N/A	N/A	N/A	300 to 600
Meramec Unit 4 STG in a CCCT Conversion	Gas	Baseload	CCCT	834	Limited	Mature	18 to 24	37	0.0092	0.0006	117	0.009	0.0044	0%	300 to 500
Meramec Unit 4 STG in a CCCT Conversion (Profile 2)	Gas	Intermediate	CCCT	834	Limited	Mature	18 to 24	37	0.0092	0.0006	117	0.009	0.0044	0%	2,900 to 5,300
Venice - 2-on-1 501F Conversion	Gas	Baseload	CCCT	254	Yes	Mature	14 to 18	41	0.0075	0.0001	117	0.0029	0.0042	0%	2,500 to 4,600
Venice - 2-on-1 501F Conversion (Profile 1)	Gas	Intermediate	CCCT	254	Yes	Mature	14 to 18	41	0.0075	0.0001	117	0.0029	0.0042	0%	2,500 to 4,600
Venice - 2-on-1 501F Conversion (Profile 2)	Gas	Intermediate	CCCT	254	Yes	Mature	14 to 18	41	0.0075	0.0001	117	0.0029	0.0042	0%	2,500 to 4,600
Greenfield - 7EA (Profile 2)	Gas	Intermediate	Cheng	96	Yes	Developing	14 to 18	38	0.018	0.0006	117	0.009	0.006	0%	200 to 400
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	Recip	99.0	Yes	Mature	14 to 18	30	0.318	0.0006	117	0.57	0.018	0%	0 to 100
Unit 3 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	237	Limited	Mature	18 to 24	10	0.1	0.0006	117	N/A	N/A	N/A	200 to 400

[26] 4 CSR 240-22.040(1)(C); 4 CSR 240-22.040(1)(D); 4 CSR 240-22.040(1)(K)1; 4 CSR 240-22.040(1)(K)3

Table 4.B.18 Coal Options – Economic Parameters and LCOE

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Economic Life, years	FOM Escalation Rate, percent	VOM Escalation Rate, percent	Fuel Escalation Rate, percent	Present Worth Discount Rate, percent	Fixed Charge Rate, percent	Annual Fixed Cost for Fuel Supply, $1,000/yr	Fixed Cost for Fuel Supply, $/MWh	LCOE w/o Emissions, ¢/kWh	Levelized Emission Costs (14), ¢/kWh	Levelized Cost of CO2, ¢/kWh	LCOE w/ Emission Costs & CO2 (14), ¢/kWh
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	USCPC	679	40	3.0%	3.0%	3.8%	7.6653%	11.46%	N/A	N/A	16.9	0.02	0.6	17.5
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	Sub-CFB	453	40	3.0%	3.0%	3.8%	7.6653%	11.83%	N/A	N/A	20.1	0.03	0.7	20.8
CCC - Greenfield -IGCC Pre Combustion	Coal	Baseload	IGCC	493	30	3.0%	3.0%	3.8%	7.6653%	12.42%	N/A	N/A	18.0	0.00	0.5	18.5
CCC - Greenfield - Oxyfuel Coal	Coal	Baseload	USCPC	620	40	3.0%	3.0%	3.8%	7.6653%	11.46%	N/A	N/A	17.2	0.00	0.7	17.9
CCC - Meramec - Oxyfuel Coal	Coal	Baseload	USCPC	620	40	3.0%	3.0%	3.8%	7.6653%	11.46%	N/A	N/A	15.7	0.00	0.7	16.4
CCC - Rush Island - Oxyfuel Coal	Coal	Baseload	USCPC	620	40	3.0%	3.0%	3.8%	7.6653%	11.46%	N/A	N/A	15.4	0.00	0.7	16.1
CCC - Rush Island - Oxyfuel -Inc Unit 1 & 2 Impacts	Coal	Baseload	USCPC	588	40	3.0%	3.0%	3.8%	7.6653%	11.46%	N/A	N/A	18.7	0.00	0.7	19.4
Greenfield - Single Unit	Coal	Baseload	IGCC	562	30	3.0%	3.0%	3.8%	7.6653%	12.42%	N/A	N/A	12.6	0.00	3.8	16.4
Greenfield - Single Unit	Coal	Baseload	SC-CFB	600	40	3.0%	3.0%	3.8%	7.6653%	11.83%	N/A	N/A	11.7	0.03	5.0	16.8
Greenfield - Single Unit	Coal	Baseload	Sub-CFB	600	40	3.0%	3.0%	3.8%	7.6653%	11.83%	N/A	N/A	10.7	0.03	5.3	16.0
Greenfield - Single Unit	Coal	Baseload	USCPC	900	40	3.0%	3.0%	3.8%	7.6653%	11.75%	N/A	N/A	9.2	0.02	4.9	14.1
Meramec - New Unit	Coal	Baseload	Sub-CFB	600	40	3.0%	3.0%	3.8%	7.6653%	11.83%	N/A	N/A	9.5	0.03	5.3	14.8
Meramec - New Unit	Coal	Baseload	USCPC	900	40	3.0%	3.0%	3.8%	7.6653%	11.75%	N/A	N/A	8.1	0.02	4.9	13.0
Rush Island - New Unit	Coal	Baseload	IGCC	562	30	3.0%	3.0%	3.8%	7.6653%	12.42%	N/A	N/A	11.1	0.00	3.8	14.9
Rush Island - New Unit	Coal	Baseload	Sub-CFB	600	40	3.0%	3.0%	3.8%	7.6653%	11.83%	N/A	N/A	9.2	0.03	5.3	14.5
Rush Island - New Unit	Coal	Baseload	USCPC	900	40	3.0%	3.0%	3.8%	7.6653%	11.75%	N/A	N/A	7.9	0.02	4.9	12.8
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	IGCC	530	30	3.0%	3.0%	3.8%	7.6653%	12.42%	N/A	N/A	15.2	0.00	4.0	19.3
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	Sub-CFB	568	40	3.0%	3.0%	3.8%	7.6653%	11.83%	N/A	N/A	12.4	0.03	5.6	18.0
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	USCPC	868	40	3.0%	3.0%	3.8%	7.6653%	11.75%	N/A	N/A	9.9	0.02	5.0	15.0

Table 4.B.19 Gas Options – Economic Parameters and LCOE

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Economic Life, years	FOM Escalation Rate, percent	VOM Escalation Rate, percent	Fuel Escalation Rate, percent	Present Worth Discount Rate, percent	Fixed Charge Rate, percent	Annual Fixed Cost for Fuel Supply, $1,000/yr	Fixed Cost for Fuel Supply, $/MWh	LCOE w/o Emissions, ¢/kWh	Levelized Emission Costs (14), ¢/kWh	Levelized Cost of CO2, ¢/kWh	LCOE w/ Emission Costs & CO2 (14), ¢/kWh
CCC - Greenfield - CCCT Amine-Based Post Combustion	Gas	Baseload	CCCT	490	30	3.0%	3.0%	2.7%	7.6653%	12.42%	5,603	1.5	14.0	0.00	0.2	14.2
Goose Creek -Inlet Chilling Augmentation	Gas	Peaking	SCCT	54	30	3.0%	3.0%	2.7%	7.6653%	12.03%	N/A	N/A	31.1	0.01	2.8	33.9
Goose Creek -Wetted Media Augmentation	Gas	Peaking	SCCT	18	30	3.0%	3.0%	2.7%	7.6653%	12.03%	N/A	N/A	18.8	0.01	2.8	21.6
Greenfield - 2-on-1 501F	Gas	Baseload	CCCT	600	30	3.0%	3.0%	2.7%	7.6653%	12.42%	5,573	1.2	8.6	0.00	1.7	10.3
Greenfield - 2x1 Wartsila 20V34SG (Profile 1)	Gas	Intermediate	Recip	17.8	30	3.0%	3.0%	2.7%	7.6653%	12.03%	108	5.9	41.1	0.01	1.9	43.0
Greenfield - Molten Carbonate	Gas	Intermediate	Fuel Cell	100	20	3.0%	3.0%	2.7%	7.6653%	12.42%	1,086	1.5	21.1	0.00	1.8	22.9
Greenfield - Two 501Fs (10% CF)	Gas	Peaking	SCCT	346	30	3.0%	3.0%	2.7%	7.6653%	12.03%	1,396	4.6	23.3	0.00	2.5	25.8
Greenfield - Two 501Fs (5% CF)	Gas	Peaking	SCCT	352	30	3.0%	3.0%	2.7%	7.6653%	12.03%	1,396	9.1	34.3	0.01	2.5	36.8
Greenfield -2-on-1 501F (Profile 2)	Gas	Intermediate	SCCT	600	30	3.0%	3.0%	2.7%	7.6653%	12.42%	3,268	2.9	15.8	0.00	1.7	17.4
Meramec - 2-on-1 501F	Gas	Baseload	SC-CFB	600	30	3.0%	3.0%	2.7%	7.6653%	12.42%	5,573	1.2	8.8	0.00	1.7	10.5
Mexico - One LM6000 Sprint (10% CF)	Gas	Peaking	SCCT	39.3	30	3.0%	3.0%	2.7%	7.6653%	12.03%	145	4.2	33.8	0.00	2.3	36.1
Mexico - One LM6000 Sprint (5% CF)	Gas	Peaking	SCCT	39.7	30	3.0%	3.0%	2.7%	7.6653%	12.03%	145	8.3	52.8	0.02	2.3	55.1
Raccoon Creek - One 7EA (5% CF)	Gas	Peaking	SCCT	73.9	30	3.0%	3.0%	2.7%	7.6653%	12.03%	339	10.5	45.6	0.01	2.8	48.5
Raccoon Creek -One 7EA (10% CF)	Gas	Peaking	SCCT	73.2	30	3.0%	3.0%	2.7%	7.6653%	12.03%	339	5.3	30.8	0.00	2.9	33.7
Meramec Unit 3 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	276	30	3.0%	3.0%	3.8%	7.6653%	11.75%	N/A	N/A	5.7	0.07	4.1	9.8
Meramec Unit 4 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	332	30	3.0%	3.0%	2.7%	7.6653%	12.42%	7,160	2.9	10.3	0.03	2.6	12.9
Meramec Unit 4 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	369	30	3.0%	3.0%	3.8%	7.6653%	11.75%	N/A	N/A	5.4	0.07	4.0	9.5
Meramec Unit 4 STG in a CCCT Conversion	Gas	Baseload	CCCT	834	30	3.0%	3.0%	2.7%	7.6653%	12.42%	7,599	1.2	8.3	0.00	1.7	10.0
Meramec Unit 4 STG in a CCCT Conversion (Profile 2)	Gas	Intermediate	CCCT	834	30	3.0%	3.0%	2.7%	7.6653%	12.42%	4,455	2.9	15.3	0.00	1.7	17.0
Venice - 2-on-1 501F Conversion	Gas	Baseload	CCCT	254	30	3.0%	3.0%	2.7%	7.6653%	12.42%	5,627	1.3	7.9	0.00	1.7	9.6
Venice - 2-on-1 501F Conversion (Profile 1)	Gas	Intermediate	CCCT	254	30	3.0%	3.0%	2.7%	7.6653%	12.42%	3,299	5.3	18.1	0.00	1.7	19.8
Venice - 2-on-1 501F Conversion (Profile 2)	Gas	Intermediate	CCCT	254	30	3.0%	3.0%	2.7%	7.6653%	12.42%	3,299	2.9	12.6	0.00	1.7	14.3
Greenfield - 7EA (Profile 2)	Gas	Intermediate	Cheng	96	30	3.0%	3.0%	2.7%	7.6653%	12.03%	698	3.9	17.4	0.01	2.3	19.7
Greenfield - Twelve Wartsila Recip Engines	Gas	Peaking	Recip	99.0	30	3.0%	3.0%	2.7%	7.6653%	12.03%	326	7.5	64.0	0.08	2.0	66.1
Unit 3 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	237	30	3.0%	3.0%	2.7%	7.6653%	12.42%	5,716	3.2	11.7	0.04	2.9	14.7

Table 4.B.20a Coal Options – Scoring Results[27]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Levelized Cost of Energy w/o Emissions Score	Levelized Cost of Energy w/ SO2, NOx Score	Levelized Cost of Energy w/ SO2, NOx & CO2 Score	Speficity of Location Score	Utility Cost w/o Emissions Total Score	Utility Cost with SO2 & NOx Total Score	Utility Cost with Emissions & CO2 Total Score	Currently Meets Regulated Emission Limits Score	Potential for Future Addition of More Stringent Controls Score	Environmental Cost Total Score	Technology Status Score	Constructability Score	Safety Training Requirements Score	Risk Reduction Total Score
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	USCPC	679	34	34	43	100	14.2	14.2	17	85	50	14.2	25	25	50	4.5
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	Sub-CFB	453	8	8	17	100	6	6	8.9	85	100	18.2	25	25	50	4.5
CCC - Greenfield -IGCC Pre Combustion	Coal	Baseload	IGCC	493	25	25	35	100	11.4	11.4	14.5	85	100	18.2	25	25	50	4.5
CCC - Greenfield - Oxyfuel Coal	Coal	Baseload	USCPC	620	31	31	40	100	13.3	13.3	16.1	85	100	18.2	25	25	50	4.5
CCC - Meramec - Oxyfuel Coal	Coal	Baseload	USCPC	620	0	0	0	100	3.5	3.5	3.5	85	100	18.2	25	25	50	4.5
CCC - Rush Island - Oxyfuel -Inc Unit 1 & 2 Impacts	Coal	Baseload	USCPC	588	19	19	28	100	9.5	9.5	12.3	85	50	14.2	25	25	50	4.5
Greenfield - Single Unit	Coal	Baseload	IGCC	562	68	68	52	100	24.9	24.9	19.9	85	50	14.2	50	25	50	6.8
Greenfield - Single Unit	Coal	Baseload	SC-CFB	600	75	75	49	100	27.1	27.1	18.9	85	50	14.2	50	25	50	6.8
Greenfield - Single Unit	Coal	Baseload	Sub-CFB	600	83	83	55	100	29.6	29.6	20.8	85	50	14.2	100	25	50	11.3
Greenfield - Single Unit	Coal	Baseload	USCPC	900	100	100	70	100	35	35	25.6	85	50	14.2	100	25	50	11.3
Meramec - New Unit	Coal	Baseload	Sub-CFB	600	60	60	23	100	22.4	22.4	10.7	85	50	14.2	100	25	50	11.3
Meramec - New Unit	Coal	Baseload	USCPC	900	73	74	49	100	26.5	26.8	18.9	85	50	14.2	100	25	50	11.3
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	IGCC	530	47	47	29	100	18.3	18.3	12.6	85	0	10.2	50	25	50	6.8
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	Sub-CFB	568	70	70	39	100	25.6	25.6	15.8	85	0	10.2	100	25	50	11.3
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	USCPC	868	90	90	63	100	31.9	31.9	23.3	85	0	10.2	100	25	50	11.3

[27] 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(C); 4 CSR 240-22.040(9)(A); 4 CSR 240-22.040(9)(A)1

Table 4.B.20b Coal Options – Scoring Results[28]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Permitting Score	Schedule Duration Score	Fuel Flexibility Score	Scalability/ Modularity/ Resource Constrained	Transmission Complexity Score	Construction Schedule and Budget Risk Score	Planning Flexibility Total Score	Availability Score	Technical Operability Training Score	Load Following/ VAR Support Score	Operability Total Score	Total Score w/o Emissions	Total Score w/ SO2 & NOx	Total Score w/ SO2, NOx & CO2
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	USCPC	679	25	0	25	100	50	25	6	100	25	25	9	49	49	51
CCC - Greenfield -Amine-Based Post Combustion	Coal	Baseload	Sub-CFB	453	25	0	25	100	50	25	6	100	25	25	9	44	44	47
CCC - Greenfield -IGCC Pre Combustion	Coal	Baseload	IGCC	493	25	7	25	75	50	25	6	50	25	25	6	45	45	48
CCC - Greenfield - Oxyfuel Coal	Coal	Baseload	USCPC	620	25	0	25	100	50	25	6	100	25	25	9	52	52	54
CCC - Meramec - Oxyfuel Coal	Coal	Baseload	USCPC	620	25	0	50	100	50	25	7	100	25	25	9	43	43	43
CCC - Rush Island - Oxyfuel -Inc Unit 1 & 2 Impacts	Coal	Baseload	USCPC	588	25	0	50	100	50	0	6	100	25	25	9	44	44	47
Greenfield - Single Unit	Coal	Baseload	IGCC	562	25	18	25	75	50	50	7	50	25	25	6	58	58	53
Greenfield - Single Unit	Coal	Baseload	SC-CFB	600	25	11	25	100	50	50	7	50	25	25	6	61	61	53
Greenfield - Single Unit	Coal	Baseload	Sub-CFB	600	25	11	25	100	50	75	8	100	50	25	10	73	73	64
Greenfield - Single Unit	Coal	Baseload	USCPC	900	25	14	25	100	50	75	8	100	50	25	10	78	78	69
Meramec - New Unit	Coal	Baseload	Sub-CFB	600	25	11	50	100	50	75	9	100	50	25	10	67	67	55
Meramec - New Unit	Coal	Baseload	USCPC	900	25	14	50	100	50	75	9	100	50	25	10	71	71	63
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	IGCC	530	25	18	50	75	50	25	7	50	25	25	6	48	48	42
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	Sub-CFB	568	25	11	50	100	50	50	8	100	50	25	10	65	65	55
Rush Island -New Unit -Includes Unit 1 & 2 Impacts	Coal	Baseload	USCPC	868	25	14	50	100	50	50	8	100	50	25	10	71	71	63

[28] 4 CSR 240-22.040(2); 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(B)1; 4 CSR 240-22.040(2)(C); 4 CSR 240-22.040(9)(A); 4 CSR 240-22.040(9)(A)1

Table 4.B.21a Gas Options – Scoring Results[29]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Levelized Cost of Energy w/o Emissions Score	Levelized Cost of Energy w/ SO2, NOx Score	Levelized Cost of Energy w/ SO2, NOx & CO2 Score	Speficity of Location Score	Utility Cost w/o Emissions Total Score	Utility Cost with SO2 & NOx Total Score	Utility Cost with Emissions & CO2 Total Score	Currently Meets Regulated Emission Limits Score	Potential for Future Addition of More Stringent Controls Score	Environmental Cost Total Score	Technology Status Score	Constructability Score	Safety Training Requirements Score	Risk Reduction Total Score
CCC - Greenfield - CCCT Amine-Based Post Combustion	Gas	Baseload	CCCT	490	57	57	69	100	21.5	21.5	25.2	85	100	18.2	25	25	50	4.5
Goose Creek -Inlet Chilling Augmentation	Gas	Peaking	SCCT	54	73	73	72	100	26.5	26.5	26.2	85	75	16.2	100	100	50	13.5
Goose Creek -Wetted Media Augmentation	Gas	Peaking	SCCT	18	100	100	100	100	35	35	35	85	75	16.2	100	100	50	13.5
Greenfield - 2-on-1 501F	Gas	Baseload	CCCT	600	100	100	100	100	35	35	35	85	75	16.2	100	50	50	12
Greenfield - 2x1 Wartsila 20V34SG (Profile 1)	Gas	Intermediate	Recip	17.8	0	0	0	100	3.5	3.5	3.5	85	50	14.2	100	50	50	12
Greenfield - Molten Carbonate	Gas	Intermediate	Fuel Cell	100	0	0	0	100	3.5	3.5	3.5	85	75	16.2	50	100	100	10.5
Greenfield - Two 501Fs (10% CF)	Gas	Peaking	SCCT	346	90	90	91	100	31.9	31.9	32.2	85	75	16.2	100	100	50	13.5
Greenfield - Two 501Fs (5% CF)	Gas	Peaking	SCCT	352	66	66	66	100	24.3	24.3	24.3	85	25	12.2	100	100	50	13.5
Greenfield -2-on-1 501F (Profile 2)	Gas	Intermediate	SCCT	600	100	100	100	100	35	35	35	85	75	16.2	100	50	50	12
Meramec - 2-on-1 501F	Gas	Baseload	SC-CFB	600	67	67	86	100	24.6	24.6	30.6	85	75	16.2	100	50	50	12
Mexico - One LM6000 Sprint (10% CF	Gas	Peaking	SCCT	39.3	67	67	67	100	24.6	24.6	24.6	85	75	16.2	100	100	50	13.5
Mexico - One LM6000 Sprint (5% CF)	Gas	Peaking	SCCT	39.7	25	25	25	100	11.4	11.4	11.4	85	25	12.2	100	100	50	13.5
Raccoon Creek - One 7EA (5% CF)	Gas	Peaking	SCCT	73.9	41	41	40	100	16.4	16.4	16.1	85	25	12.2	100	100	50	13.5
Raccoon Creek -One 7EA (10% CF)	Gas	Peaking	SCCT	73.2	73	73	73	100	26.5	26.5	26.5	85	75	16.2	100	100	50	13.5
Meramec Unit 3 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	276	100	100	95	100	35	35	33.4	85	0	10.2	100	25	50	11.3
Meramec Unit 4 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	332	53	53	50	100	20.2	20.2	19.3	85	25	12.2	100	25	50	11.3
Meramec Unit 4 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	369	100	100	100	100	35	35	35	85	0	10.2	100	25	50	11.3
Meramec Unit 4 STG in a CCCT Conversion	Gas	Baseload	CCCT	834	71	72	93	100	25.9	26.2	32.8	85	75	16.2	100	25	50	11.3
Meramec Unit 4 STG in a CCCT Conversion (Profile 2)	Gas	Intermediate	CCCT	834	100	100	100	100	35	35	35	85	75	16.2	100	25	50	11.3
Venice - 2-on-1 501F Conversion	Gas	Baseload	CCCT	254	100	100	100	100	35	35	35	85	75	16.2	100	50	50	12
Venice - 2-on-1 501F Conversion (Profile 1)	Gas	Intermediate	CCCT	254	0	0	0	100	3.5	3.5	3.5	85	75	16.2	100	50	50	12
Venice - 2-on-1 501F Conversion (Profile 2)	Gas	Intermediate	CCCT	254	100	100	100	100	35	35	35	85	75	16.2	100	50	50	12
Greenfield - 7EA (Profile 2)	Gas	Intermediate	Cheng	96	94	94	91	100	33.1	33.1	32.2	85	75	16.2	50	50	50	7.5
Greenfield - Twelve Wartsila Recip Engines	Gas	Peaking	Recip	99.0	0	0	0	100	3.5	3.5	3.5	85	25	12.2	100	100	50	13.5
Unit 3 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	237	39	39	25	100	15.8	15.8	11.4	85	25	12.2	100	25	50	11.3

29 4 CSR 240-22.040(2); 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(B)1; 4 CSR 240-22.040(2)(C); 4 CSR 240-22.040(9)(A); 4 CSR 240-22.040(9)(A)1

Table 4.B.21b Gas Options – Scoring Results[30]

Resource Option	Fuel Type	Operations Mode	Technology Description	Full Load Net Plant Output, MW (95 F)	Permitting Score	Schedule Duration Score	Fuel Flexibility Score	Scalability/ Modularity/ Resource Constrained	Transmission Complexity Score	Construction Schedule and Budget Risk Score	Planning Flexibility Total Score	Availability Score	Technical Operability Training Score	Load Following/ VAR Support Score	Operability Total Score	Total Score w/o Emissions	Total Score w/ SO2 & NOx	Total Score w/ SO2, NOx & CO2
CCC - Greenfield - CCCT Amine-Based Post Combustion	Gas	Baseload	CCCT	490	100	32	0	75	50	25	6	100	25	25	9	60	60	63
Goose Creek -Inlet Chilling Augmentation	Gas	Peaking	SCCT	54	50	83	0	75	100	75	9	100	100	100	15	80	80	80
Goose Creek -Wetted Media Augmentation	Gas	Peaking	SCCT	18	50	100	0	75	100	75	9	100	100	100	15	89	89	89
Greenfield - 2-on-1 501F	Gas	Baseload	CCCT	600	50	50	0	75	50	75	7	100	50	25	10	80	80	80
Greenfield - 2x1 Wartsila 20V34SG (Profile 1)	Gas	Intermediate	Recip	17.8	50	75	0	75	100	75	9	100	50	25	10	48	48	48
Greenfield - Molten Carbonate	Gas	Intermediate	Fuel Cell	100	100	11	0	100	50	75	8	100	100	25	11	49	49	49
Greenfield - Two 501Fs (10% CF)	Gas	Peaking	SCCT	346	50	13	0	75	100	75	8	100	100	100	15	84	84	85
Greenfield - Two 501Fs (5% CF)	Gas	Peaking	SCCT	352	50	13	0	75	100	75	8	100	100	100	15	73	73	73
Greenfield -2-on-1 501F (Profile 2)	Gas	Intermediate	SCCT	600	50	75	0	75	100	75	9	100	50	25	10	82	82	82
Meramec - 2-on-1 501F	Gas	Baseload	SC-CFB	600	50	50	0	75	50	75	7	100	50	25	10	70	70	76
Mexico - One LM6000 Sprint (10% C	Gas	Peaking	SCCT	39.3	50	13	0	75	100	75	8	100	100	100	15	77	77	77
Mexico - One LM6000 Sprint (5% CF	Gas	Peaking	SCCT	39.7	50	13	0	75	100	75	8	100	100	100	15	60	60	60
Raccoon Creek - One 7EA (5% CF)	Gas	Peaking	SCCT	73.9	50	13	0	75	100	75	8	100	100	100	15	65	65	65
Raccoon Creek -One 7EA (10% CF)	Gas	Peaking	SCCT	73.2	50	13	0	75	100	75	8	100	100	100	15	79	79	79
Meramec Unit 3 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	276	25	100	25	25	50	75	7	100	50	25	10	73	73	72
Meramec Unit 4 Boiler NG Conversio	Gas	Baseload	Sub. Crit.	332	50	100	0	25	50	75	6	100	50	25	10	60	60	59
Meramec Unit 4 Boiler Replacement and STG Rebuild	Gas	Baseload	Sub. Crit.	369	25	100	25	25	50	75	7	100	50	25	10	73	73	73
Meramec Unit 4 STG in a CCCT Conversion	Gas	Baseload	CCCT	834	50	52	0	75	50	50	6	100	50	25	10	70	70	77
Meramec Unit 4 STG in a CCCT Conversion (Profile 2)	Gas	Intermediate	CCCT	834	50	100	0	75	100	50	8	100	50	25	10	81	81	81
Venice - 2-on-1 501F Conversion	Gas	Baseload	CCCT	254	50	45	0	75	50	75	7	100	50	25	10	80	80	80
Venice - 2-on-1 501F Conversion (Profile 1)	Gas	Intermediate	CCCT	254	50	0	0	75	100	75	8	100	50	25	10	49	49	49
Venice - 2-on-1 501F Conversion (Profile 2)	Gas	Intermediate	CCCT	254	50	0	0	75	100	75	8	100	50	25	10	81	81	81
Greenfield - 7EA (Profile 2)	Gas	Intermediate	Cheng	96	50	75	0	75	100	75	9	100	50	50	11	77	77	76
Greenfield - Twelve Wartsila Recip. Engines	Gas	Peaking	Recip	99.0	50	0	0	100	100	75	8	100	100	100	15	53	53	53
Unit 3 Boiler NG Conversion	Gas	Baseload	Sub. Crit.	237	50	100	0	25	50	75	6	100	50	25	10	56	56	51

30 4 CSR 240-22.040(2); 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(B)1; 4 CSR 240-22.040(2)(C); 4 CSR 240-22.040(9)(A); 4 CSR 240-22.040(9)(A)1

4.5 Compliance References

Chapter 4 – Appendix B

5. Renewable and Storage Resources

Highlights

- *Today 4% of Ameren Missouri's energy is produced by renewable resources, mostly from hydroelectric plants.*
- *With the help of Black and Veatch, Ameren Missouri has identified several promising renewable projects within its service territory.*
- *Although the region is flush with biomass materials, the use for power plant operations is highly dependent on the emergence of a sustainable fuel supply.*
- *Ameren Missouri has not only developed a long-term plan to meet the state's Renewable Energy Standard but has also evaluated the need to meet potential Federal renewable requirements.*
- *Although existing renewable resources meet non-solar requirements, Ameren Missouri will be procuring solar energy credits throughout the implementation period.*

Ameren Missouri has analyzed various renewable and energy storage options in the region. Most of the energy storage options are relatively small and expensive; however, pumped storage and compressed air storage were evaluated in detail as the most promising energy storage options. In 2009, Ameren Missouri worked with Black and Veatch to identify potential renewable projects in the region including landfill gas, hydroelectric, biomass, and anaerobic digestion. Black and Veatch also helped Ameren review the various solar technologies to determine which ones would be most appropriate for the region. All the information collected supported the analysis to determine which projects were the most promising and need to be considered further. Most of the evaluated renewable projects were small and opportunistic in nature. Wind and biomass co-firing showed the highest potential of renewable resources. Both have limitations – transmission issues for wind and fuel supply for co-firing.

In November of 2008, Missouri voters approved Proposition C, also known as the Clean Energy Initiative or the Missouri Renewable Energy Standard. Unfortunately, Proposition C contained two conflicting goals. On one hand, it set a goal of acquiring renewable energy equal to 15% of our electricity sales by 2021 with 2% of that amount coming from solar. On the other hand, it limited rate increases supporting new renewables to 1% or less. Based on current costs for renewable energy, both goals cannot be met at the same time.

Ameren Missouri modeled renewable portfolios for both the state RES and a potential Federal RES. One distinguishing difference between the two was that the Federal RES allowed no-carbon resources to reduce the base from which the energy requirement is calculated. Another difference was the 4% Federal RES rate cap, which did not constrain compliance, unlike the 1% cap in the Missouri RES. In both portfolios wind was a major contributor to compliance, while the Federal RES also included substantial biomass co-firing. In fact, the amount of co-firing included exceeded the estimated fuel supply. Without a sustainable fuel supply, co-firing would be supplanted with additional wind resources.

The renewable portfolios were included in the alternative resource plans as described in Chapter 9. It is noteworthy that wind was also included as a major supply-side resource in the development of alternative resource plans to compete with pumped hydro and the thermal resources identified in Chapter 4. One major weakness of wind is its limited availability during summer peak hours. To compensate for this weakness Ameren Missouri paired wind with peaking resources. Simple cycle combustion turbines are a great compliment for wind as they are primarily functioning during peak conditions.

5.1 Existing Renewable and Storage Resources

Currently Ameren owns and operates 382 MW of hydroelectric resources and 440 MW of pumped storage with an additional purchase power agreement for 102 MW of wind. In December, 2010 Ameren Missouri completed the installation of approximately 100 kW of solar panels using monocrystalline, polycrystalline and thin-film technologies. Construction of 15 MWs of landfill gas generation at the Fred Weber site will begin in early 2011.

Keokuk

Ameren Missouri's Keokuk hydroelectric plant is located on the Mississippi River at Keokuk, Iowa, 180 miles north of St. Louis.

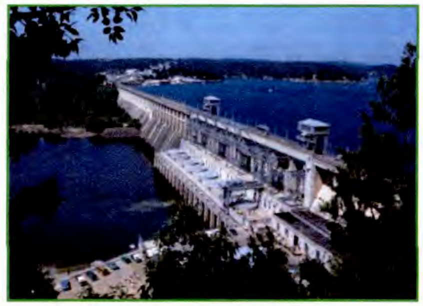
More than a million cubic yards of earth and rock were excavated to build the Keokuk dam and plant, which began operation in 1913. The history of the site as a power source began as far back as 1836, when Robert E. Lee conducted a survey for the War Department and called attention to the power potential of this section of the Mississippi. An engineering marvel of its time, Keokuk is the largest privately owned and operated dam and hydroelectric generating plant on the Mississippi River. Over the years, Ameren Missouri has continued to invest millions of dollars for the modernization and repair of the plant and dam.

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

As it passes through the power plant, falling water spins turbines, or water wheels, which drive generators that produce electricity. Keokuk Plant is a "run-of-river plant," meaning that all water flowing downstream passes the plant on a daily basis. No water is stored. An average day of operation at Keokuk Plant saves the equivalent of nearly 1,000 tons of coal.

Osage

Ameren Missouri's Osage hydroelectric plant is located in Lakeside Missouri on the Osage River at the Lake of the Ozarks.



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

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

Taum Sauk

The Taum Sauk pumped storage plant is located approximately 120 miles southwest of St. Louis in the scenic Ozark highlands.

Taum Sauk Plant began operation in 1963 and the upper reservoir rebuild project was completed in 2010. Taum Sauk is used primarily on a peaking basis and is put into operation when the demand for electricity is greatest. The pump storage system works much like a conventional hydroelectric plant, but is usually used only to meet daily peak power demands for short periods. Water stored in an upper reservoir is released to flow through turbines and into a lower reservoir during high energy demands. Then, overnight, when the demand for electricity is low, the water is pumped back into the upper reservoir, where it is stored until needed. As water passes through the powerhouse, water spins the turbines, which drive generators to produce electricity. The Taum Sauk facility has a pump back efficiency of 0.714.

Pioneer Prairie Wind Farm

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

5.2 Potential New Storage Resources

A high-level fatal flaw analysis was conducted as part of the first stage of the supply-side selection analysis. 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 list of storage options and fatal flaw analysis are included in Chapter 5 – Appendix A. Two options passed the initial screen; pumped hydro and compressed air energy storage.

Pumped Hydro Energy Storage

Conventional pumped hydro 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. In the current IRP, Ameren Missouri has internally updated the capital costs based on recent construction experience at its Taum Sauk facility.

Compressed Air Energy Storage

A Compressed Air Energy Storage (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 charges the storage vessel.

Compressed Air Storage System

Compressed air for a CAES plant may be stored in 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.

At an assumed constant pressure of about 1000 psi, the required live storage volume for a compensated pressure facility capable of generating 600 MW for 10 hours is about 12.5 million ft^3, or about 285 AF (Acre Feet).[1,2]

Energy Production System

During power generation, cavern air flows first through a recuperator. In the recuperator, the high pressure cavern air is preheated by heat recovered from low pressure expander exhaust gases. After being preheated in the recuperator, the air flows to a combustor in which natural gas is burned to heat the air before it is delivered to the expander inlet at a design pressure dependent on the underground formation. Energy used to compress the air is assumed to come from wind generation for this study. The following assumptions have been made for this gas fueled CAES facility:

- Combustion controls for fired turboexpanders
- Staged centrifugal compression
- Two 300 MW fired turboexpanders
- Two recuperators

Performance, emissions, and cost estimates were prepared using information supplied by Ameren Missouri and through Black & Veatch research.[3] The capital cost estimates are adjusted to a 2009 EPC (engineering, procurement, and construction) overnight basis, with a project scope that was consistent with other capital cost estimates presented in this report.

Table 5.1 shows the energy storage technologies that were evaluated. Chapter 5 – Appendix B contains more detailed information.

[1] 4 CSR 240-22.040(8)(B)1.
[2] 4 CSR 240-22.040(1)(J)
[3] 4 CSR 240-22.040(8)(B)1.

Table 5.1 Energy Storage Resource Details[4]

Resource Option	Operations Mode	Plant Output, MW	Total Project Cost -Includes Owners Cost, $/kW	Heat Rate HHV, Btu/kWh	Assumed Annual Capacity Factor, percentage	Annual MWh's output	LCOE, ¢/kWh
Pumped Hydro Storage	Peaking	600	$2,830	n/a	25%	1,314,000	21.77
Compressed Air Energy Storage	Peaking	600	$1,680	4,400	30%	1,576,800	18.30

Pumped storage was selected as the energy storage resource to be evaluated in the remaining resource planning process as a major supply-side resource.

5.3 Potential New Renewable Resources

In 2009 Ameren Missouri contracted with Black and Veatch[5] to identify renewable potential in Missouri and more specifically Ameren Missouri's service territory. The study considered 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 5 – Appendix B. Ameren Missouri performed an internal analysis related to wind generation based on data received from a variety of developers in response to its RFP as well as unsolicited proposals.

5.3.1 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 2010 to 2020 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 CO2. 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 20 countries.

[4] 4 CSR 240-22.040(1)(B); 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(F); 4 CSR 240-22.040(1)(G); 4 CSR 240-22.040(1)(J)

[5] 4 CSR 240-22.040(8)(B)1.; 4 CSR 240-22.040(8)(C)1.

Applications

LFG can be used to generate electricity and/or 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 or a gas-fired boiler. Testing with microturbines and fuel cells is also underway, although these technologies do not appear to be economically viable for power generation.

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 15 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 Missouri Department of Natural Resources (MoDNR), which provided additional details on candidate landfills within the state. According to MoDNR'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, 22 landfills were identified as candidates for LFG projects. MoDNR provided additional information regarding estimated gas production curves (from 2010 through 2020) 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 2010 to 2020 was also estimated. Based on review of the information provided by

MoDNR and internal estimates of generation capacities, Black & Veatch identified seven landfills within Ameren Missouri's service territory with potential to provide greater than 2 MW of LFG-fired generation capacity throughout the 2010 to 2020 timeframe:

- Fred Weber
- Bridgeton
- Missouri Pass
- Maple Hill
- Lemons East
- Jefferson City (Unavailable - being developed by Ameresco, Inc. and all energy will be sold to Columbia Water and Light under a 20-year PPA)
- Autoshred (Disqualified - no collection system and low volumes of gas)

For the five most promising 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 five 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 Fred Weber, these projects are likely to employ reciprocating engines to generate electricity from LFG. Due to the larger generation capacity of the Fred Weber project, this project will employ combustion turbine technologies.

Table 5.2 contains details of the five potential landfill gas projects. Chapter 5 – Appendix B contains more detailed information.

Table 5.2 Potential Landfill Gas Resources[6]

Resource Option	Renewable Resource	Operations Mode	Technology Description	Plant Output, MW	First Year Fuel Cost, \$/MBtu	Total Project Cost - Includes Owners Cost, \$/kW	Assumed Annual Capacity Factor, perceutage	Annual MWh's output	Forced Outage Rate, percentage	LCOE, ¢/kWh
Bridgeton	LFG	Baseload	RICE	8	$2.00	$3,800	92%	64,474	5%	11.42
Fred Weber	LFG	Baseload	CT	13	$2.00	$3,750	90%	102,492	5%	10.90
Lemons East	LFG	Baseload	RICE	2	$2.00	$4,050	90%	15,768	5%	14.17
Missouri Pass	LFG	Baseload	RICE	2.5	$2.00	$4,460	90%	19,710	5%	12.86
Veolia Maple Hill	LFG	Baseload	RICE	4	$2.00	$4,050	92%	32,237	5%	13.94

5.3.2 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 30 MW were identified.

6 4 CSR 240-22.040(1)(A); 4 CSR 240-22.040(1)(B); 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(I)

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 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 Idaho National Laboratory (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 facilities 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 hydropower sites were not included in this analysis.
- Project size was limited to sites between 2 and 30 MW.

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. 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 5.3 contains details of the four potential hydroelectric projects. Chapter 5 – Appendix B contains more detailed information.

Table 5.3 Potential Hydroelectric Resources[7]

Resource Option	Renewable Resource	Operations Mode	Plant Output, MW	Total Project Cost -Includes Owners Cost, $/kW	Assumed Annual Capacity Factor, percentage	Annual MWh's output	Forced Outage Rate, percentage	LCOE, ¢/kWh
Ozark Beach	Hydro	Baseload	5	$3,050	40%	17,520	5%	$11.80
Clearwater	Hydro	Baseload	5.3	$4,880	40%	18,571	5%	$18.92
Pomme De Terre	Hydro	Baseload	4.6	$4,270	60%	24,178	5%	$11.01
Mississippi L&D 21	Hydro	Baseload	10	$6,100	40%	35,040	5%	$23.67

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.

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.

5.3.3 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 &

[7] 4 CSR 240-22.040(1)(A); 4 CSR 240-22.040(1)(B); 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(I)

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 December 2006, a report issued jointly by the U.S. EPA and the Combined Heat and Power Partnership estimated that 220 MW of generation is produced through the anaerobic digestion of municipal biosolids at 76 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 December 2008, there are currently 30 MW of electricity generated from more than 108 farm-based digesters. Another 25 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.

5.3.3.1 Municipal Biosolids

Biosolids is the term given to processed sludge removed from wastewater treatment. Biosolids are rich in organic materials and can be used to produce energy either through combustion or anaerobic digestion; however, the high moisture and high ash content of biosolids create challenges when biosolids are combusted for energy. Even dewatered biosolids typically have a moisture content of approximately 70 percent, and ash contents are typically greater than 20 percent. Combustion becomes more attractive if waste heat or natural evaporation can be used to dry biosolids.

Anaerobic digestion is commonly used in municipal wastewater treatment as a first-stage treatment process for sewage sludge; however, historically, utilization of the biogas generated from municipal AD facilities has been a secondary consideration.

Generation systems are rarely optimized for energy production, and it is common for water utilities to flare the biogas generated. As interest in sustainability increases, more water utilities, such as St. Louis MSD, are looking at biosolids as a potential energy resource. St. Louis MSD recently issued a request for qualifications (RFQ) for a contract to develop a comprehensive solids handling master plan. Black & Veatch's Water Division received notification of an award for this contract. The purpose of the MSD's Comprehensive Biosolids Handling Master Plan is to "assess the Districts' biosolids handling systems from wet sludge to final disposal and provide a Master Plan to provide guidance for decades to come." MSD recognizes that this will require a substantial effort because there are a variety of options to consider and evaluate. Some of the primary issues which will need to be examined are discussed below.

Resource Availability

St. Louis MSD currently operates seven wastewater treatment facilities in the St. Louis region; however, the two largest facilities, Bissell Point WWTP and Lemay WWTP, account for approximately 80 percent of the total biosolids production. An evaluation was performed to identify the potential gas production at each of these plants. The gas production was based on the current average and design solids production reported for each of these plants. This information was obtained from the MSD Request for Proposal (RFP) for its Comprehensive Solids Handling Master Plan (January 2009). This information included permitted and design plant flow, current and design total dry solids quantities, and a brief description of the solids treatment processes at each facility. No information was provided addressing solids characterization, volatility, or solids concentrations.

A number of assumptions were used for this evaluation, based on engineering experience. These assumptions include the following:

- Solids distribution - A 50:50 split was used for primary solids (PS) and waste activated sludge (WAS) or trickling filter humus. While this ratio is fairly typical, the actual PS:WAS ratio can vary significantly depending on the characteristics of the plant influent and the design and operation of the treatment processes.
- Volatile solids content - The volatile content of solids varies based on the characteristics of the plant influent and type and operation of the treatment processes. While volatility varies significantly, it typically ranges from 60 percent to 85 percent. The following volatile solids (VS) percentages were applied to the solids:
    - Primary solids – 80 percent VS.

  - WAS (high rate system) – 78 percent VS.
  - WAS (oxidation ditch) – 75 percent VS.
  - Trickling filter humus – 73 percent VS.
- Volatile solids reduction - The volatile solids reduction (VSr) during digestion varies depending on the volatility of the digester feed, degradability of the feed, and digestion design and operation. Typical VSr values range from 35 to 55 percent for conventional digestion on a mixed sludge (similar to that produced by the MSD plants). A value of 45 percent VSr was used for this evaluation.
- Gas production and methane content - The anaerobic digestion process typically generates gas at a rate of 13 to 17 scf/lb VS destroyed. The production rate can be affected by the type and characteristics of the feed solids. A value of 16 scf/lb VS destroyed was used for this evaluation. A biogas methane content of 600 Btu/scf was used for this evaluation, with the remainder as carbon dioxide and trace components, including hydrogen sulfide, nitrogen, and siloxanes.
- Unit cost factors - Preliminary opinions of probable costs were developed based on high level estimates of unit costs for capital and operations and maintenance (O&M) requirements. The following unit costs were used for annual O&M costs[8]:
  - Electricity: 0.07 $/kWh.
  - Labor: $27/hr.
  - Anaerobic digestion: $0.07/gal primary digester capacity.

Capital costs are based on providing anaerobic digestion capacity, gas cleaning, and power generation equipment for the average solids quantities. While actual design is usually based on maximum month quantities, current average quantities were used to represent the costs that Ameren Missouri may be required to offset or support at the present time. Equipment at plants that have the largest difference between current and design capacity (e.g., Bissell Point and Lemay) can be acquired in phases to reduce initial capital costs. Projects such as these can be expanded as the solids quantities increase. Annual operating costs are based on the estimated gas production at current conditions. Engine generators were used for power production for the Lemay and Bissell Point plants; microturbines were used for all other plants. Gas cleaning includes hydrogen sulfide, moisture, and siloxanes removal at all plants.

5.3.3.2 Animal Manures

Animal manures from CAFOs provide another opportunity for the creation of biogas through anaerobic digestion. Farm-based anaerobic digestion projects are generally less than 400 kW in size. They typically rely on relatively simple technologies such as covered lagoon or horizontal plug flow reactors. The animal type, population, and manure collection/management system are the largest factors in determining the

[8] 4 CSR 240-22.040(1)(F)

potential and feasibility of a farm-based digestion project. The technology type and process parameters (such as temperature and residence time) also influence the biogas producing potential. In recent years there has been a trend towards larger, more advanced complete mix digesters.

As stated previously, digestion projects are often not motivated solely by energy issues. Waste reduction and stabilization are generally the primary drivers. Larger projects benefit from economies of scale and hold the most potential to be economically viable with regards to energy production.

Resource Availability

The U.S. EPA AgStar program keeps track of agricultural digesters in the U.S. and also estimates some generation potential. According to the EPA, there currently are no animal manure anaerobic digesters greater than 1 MW in the state; however, the EPA does estimate a total potential of 20 MW from 200 swine operations around the state with greater than 5,000 head of swine. This relates to an average project size of approximately 100 kW, which Black & Veatch considered too small to be considered for utility scale projects.

All CAFO operations in the state of Missouri must be permitted through the Missouri Department of Natural Resources (MO DNR) based on the number of animal units at each location. Although there are over 500 permitted CAFO operations in the state, in general, the resource is too dispersed for much of it to be economically accessible. Black & Veatch assumes that only projects with potential for greater than 1 MW of production are worthy of consideration for utility scale projects.

It was assumed that each head of livestock could support sustainable electric generation capacity ranging from 1.1 to 140 watts. This value depended upon the type of livestock, as shown in Table 5.4.

Table 5.4 Output per Livestock Type[9]

Livestock Type	System Capacity (Watts per Head)
Dairy Cattle	138.5
Swine	25.8
Chicken (layers)	1.1
Sheep	12.4
Source: California Biomass Collaborative	

Candidate Anaerobic Digestion Characterization

Table 5.5 contains details of the potential anaerobic digestion projects. Chapter 5 – Appendix B contains more detailed information.

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

Table 5.5 Potential Anaerobic Digestion Resources[10]

Resource Option	Renewable Resource	Operations Mode	Technology Description	Plant Output, MW	Total Project Cost -Includes Owners Cost, $/kW	Heat Rate HHV, Btu/kWh	Assumed Annual Capacity Factor, percentage	Annual MWh's output	Forced Outage Rate, percentage	LCOE, ¢/kWh
Mercer County 1	AD	Baseload	RICE	3.9	$13,860	12,000	90%	30,748	5%	39.77
Sullivan County 1	AD	Baseload	RICE	3.2	$14,180	12,000	90%	25,229	5%	40.53
Gentry County 1	AD	Baseload	RICE	2.1	$14,990	12,000	90%	16,556	5%	42.79
Putnam County 1	AD	Baseload	RICE	2.1	$15,060	12,000	90%	16,556	5%	42.99
Sullivan County 2	AD	Baseload	RICE	2.1	$15,060	12,000	90%	16,556	5%	42.99
Gentry County 2	AD	Baseload	RICE	1.9	$15,310	12,000	90%	14,980	5%	43.63
Sullivan County 3	AD	Baseload	RICE	1.8	$15,370	12,000	90%	14,191	5%	43.77
Mercer County 2	AD	Baseload	RICE	1.1	$17,010	12,000	90%	8,672	5%	46.16
Putnam County 2	AD	Baseload	RICE	3.2	$14,180	12,000	90%	25,229	5%	40.53
Sullivan County 4	AD	Baseload	RICE	3.1	$14,240	12,000	90%	24,440	5%	40.80
Vernon County	AD	Baseload	RICE	1.4	$16,250	12,000	90%	11,038	5%	46.20
Johnson County	AD	Baseload	RICE	2.5	$14,620	12,000	90%	19,710	5%	41.68
Lincoln County	AD	Baseload	RICE	1.4	$16,130	12,000	90%	11,038	5%	45.80
Lewis County	AD	Baseload	RICE	1.2	$16,820	12,000	90%	9,461	5%	47.68

5.3.4 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.[11] 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

[10] 4 CSR 240-22.040(1)(B); 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(I); 4 CSR 240-22.040(1)(J)
[11] 4 CSR 240-22.040(1)(K)(4)

economically disadvantage biomass compared to fossil fuels. Table 5.6 presents the typical advantages and disadvantages of biomass fuels compared to coal.

Table 5.6 Biomass Pros and Cons

Biomass Negatives	Biomass Positives
Lower Heating Value	Lower Sulfur, Heavy Metals, & 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 Disperse	"Green" Image
Limited Fuel Market	Incentives may be available

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.

Further, biomass fuels contain little sulfur compared to coal and so produce less sulfur dioxide. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals such as mercury, cadmium, and lead. On the other hand, biomass combustion still must cope with some of the same pollution issues as larger coal plants. Primary pollutants are NO_x, particulate matter (PM), and carbon monoxide (CO). Standard air quality control technologies are used to manage these pollutants.

Biomass power projects must maintain a delicate balance to ensure long term sustainability with minimal environmental impact. Several states impose specific criteria on biomass power projects for them to be classified as renewable energy sources. A key concern is sustainability of the feedstock. Most biomass projects target utilization of biomass waste material for energy production, saving valuable landfill space. Targeting certain wastes for power production (such as the forest thinnings for fire threat reduction activities) can also address other emerging problems. Projects relying on forestry or agricultural products must be careful to ensure that fuel harvesting and collection practices are sustainable and provide a net benefit to the environment.

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. The clean biomass fuel typically reduces emissions of sulfur, carbon dioxide, nitrogen oxides, and heavy metals, such as mercury. Furthermore, biomass co-firing directly offsets coal use.

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.

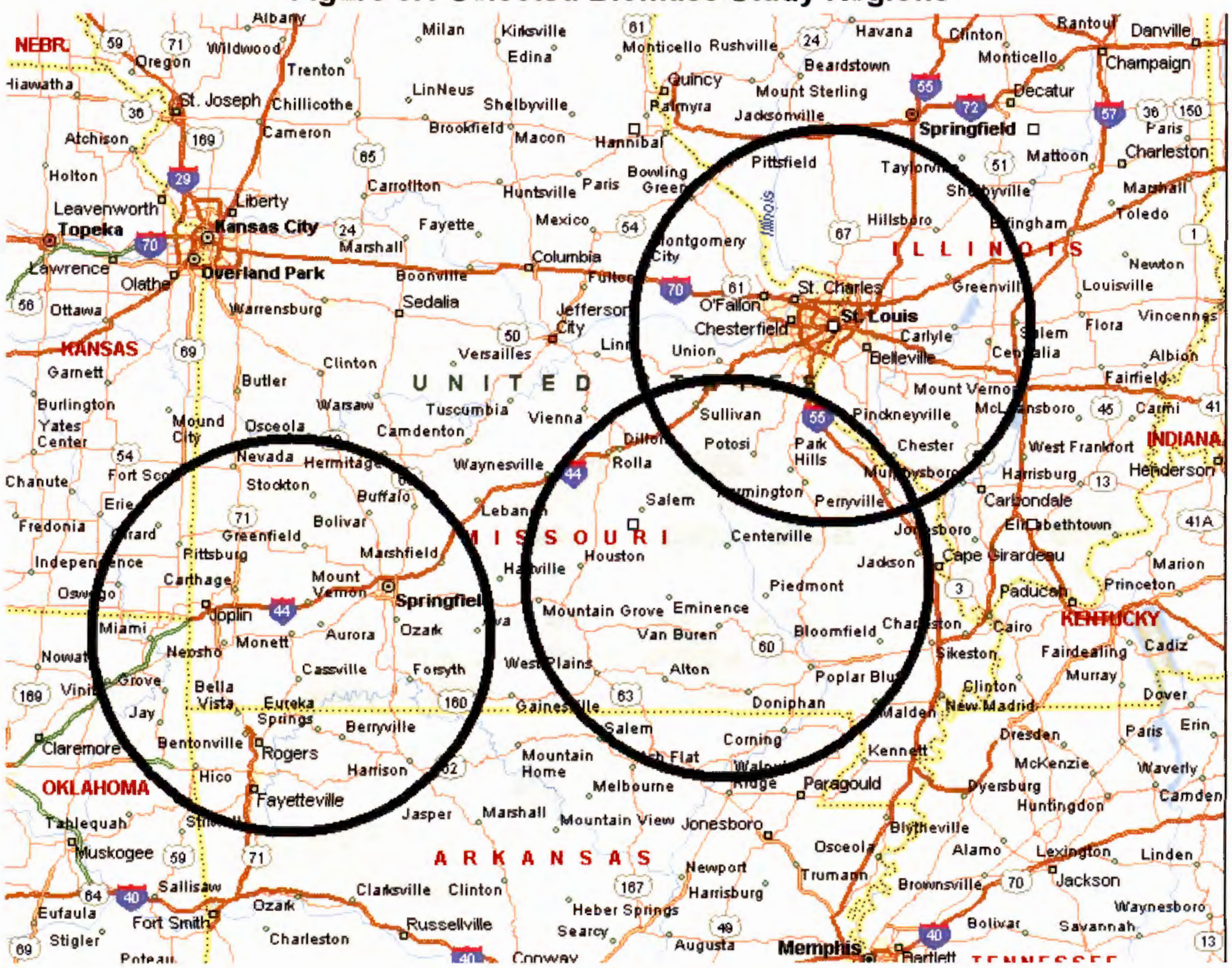
Selected Biomass Inventory Areas

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.[12]

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 5.1 shows a map of Missouri with the identified study regions.

Figure 5.1 Selected Biomass Study Regions



[12] 4 CSR 240-22.040(1)(K)(4)

Though a portion of all of three study regions fell outside of the state of Missouri, Black and Veatch were focused primarily on the resources which could be found within Missouri's borders. Projects dependent on biomass resources being brought in from outside the state are possibly at a greater risk of encountering issues with long term fuel supply. Issues could arise if states continue to pass legislation setting Renewable Energy Standards (RES) or if a Federal RES is adopted. Still, some exceptions were made to investigate the potential of resources brought in from outside the state. The most notable exception is poultry litter brought in from Arkansas. Since a significant amount of poultry litter is already brought into Missouri from Arkansas for disposal through land application, further investigation of the potential of this resource is warranted.

5.3.4.1 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.

The objective of the resource assessment was to develop supply curves ($/MBtu vs. MBtu/day potential) for the identified biomass fuels. These were intended to show the values and quantities of available biomass fuel in the context of the current markets in the selected regions. An ideal biomass project would be supplied by as few fuel suppliers as possible to simplify logistics and contracting; therefore, efforts were made to identify the largest suppliers in each of the identified areas.

Black & Veatch compiled lists of suppliers in each category from phone listings and other directories. In all, Black & Veatch identified 405 potential biomass suppliers. An attempt was made to contact all 405 of these suppliers by telephone, and contact was made with the vast majority. In addition to the 405 potential suppliers that were identified, Black & Veatch placed high priority on identifying and communicating with officials from government agencies, academia, and other groups who have specialized knowledge regarding Missouri's agricultural and forest industries.

Identification of Potential Suppliers

Detailed inventories were performed for the three selected regions. Data collected includes cost, quantity, material composition, and current disposition of the candidate fuel(s), as well as the location, delivery capabilities, and key personnel for each supplier. The data was collected in one database, which was then used for further analysis and supply curve development.

Resources were placed into one of four categories, which are described in the following subsections. These categories include the following:[13]

- ***Primary Forest Residues:*** The primary wood product industry consists of sawmills, pulp chip producers, and pulp and paper mills. Residues from these sources include wood chips, bark, sawdust, wood shavings, and wood scraps. These residues are typically very wet (50 percent moisture or greater). Primary forest residues are typically concentrated at the source (i.e., at the sawmill).
- ***Secondary Forest Products:*** The secondary wood product industry consists of wastes from the manufacture of pallets, furniture, or other finished products. Residues from these sources include wood chips, sawdust, wood shavings, and wood scraps. These residues are typically drier, although new pallet manufacturing often uses fresh lumber and has wetter residues.
- ***Urban Wood Waste:*** Urban wood waste is a broad category including wood from residential and commercial yard work (green waste), tree trimmings, construction and demolition debris, land clearing, and other urban sources. This material can be very concentrated geographically (as in the case of landfills) or can be very dispersed (as in the case of tree trimmings).
- ***Poultry Litter:*** Poultry litter is a mixture of bedding material and poultry waste such as manure and feathers. Typically, fibrous waste materials such as woodchips, sawdust, or peanut hulls are used for bedding material. Local resource availability generally determines what is used as the bedding material. Most poultry litter is generated from raising broiler hens. The bedding material is changed out periodically, typically every 6 to 8 weeks. The nutrient content of poultry litter also makes it well suited for use as fertilizer.

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 5.7.

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

Table 5.7 Biomass Fuel Property Assumptions[14]

Fuel Type	Moisture Content (%)	Higher Heating Value (Btu/dry lb)	Bulk Density (lb/ft3)
Green wood chips	50	8500	34
Green saw dust	50	8500	23
Dry wood chips	10	8500	25
Dry saw dust	10	8500	17
Bark	50	8500	34
Poultry litter	30	6500	n/a

Transportation Cost

Hauling costs can be calculated in several ways, but generally costs for hauling contractors are based either on haul time or distance. Shorter hauls (i.e., approximately 100 miles and under) are generally charged on a per-hour basis while longer hauls are charged on a per-mile basis. Hauling costs can vary based on the type of truck bed; "walking floor" or "live bottom" trailers are more expensive than standard trailers.

To obtain a reasonable estimate for hauling costs, Black & Veatch contacted two local hauling contractors: J.B. Hunt and C.H. Robinson. Based on information from these contractors and hauling data from previous 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:

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

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

[14] 4 CSR 240-22.040(1)(A)

curve for each of the three areas selected. Supply curves for the promising individual fuel resources are provided in Figure 5.2 for the St. Louis region, Figure 5.3 for the Ellington region, and Figure 5.4 for the Monett region.

Figure 5.2 Biomass Fuel Supply Curve for St. Louis Region

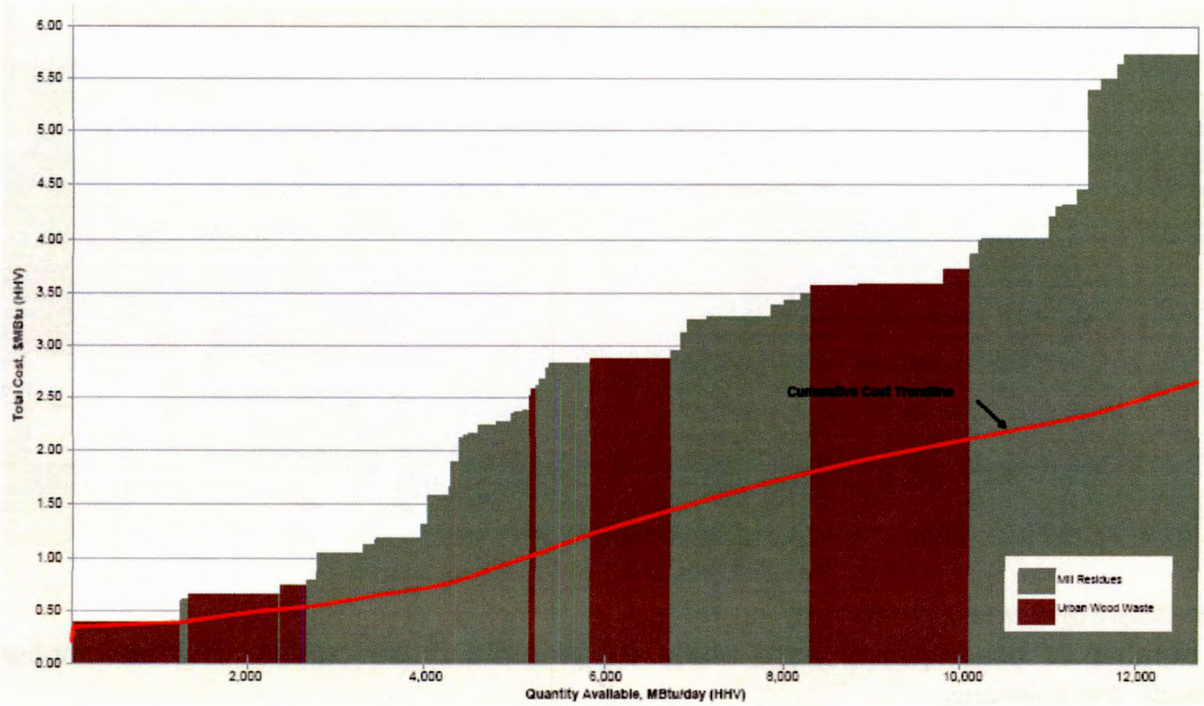


Figure 5.3 Biomass Fuel Supply Curve for Ellington Region

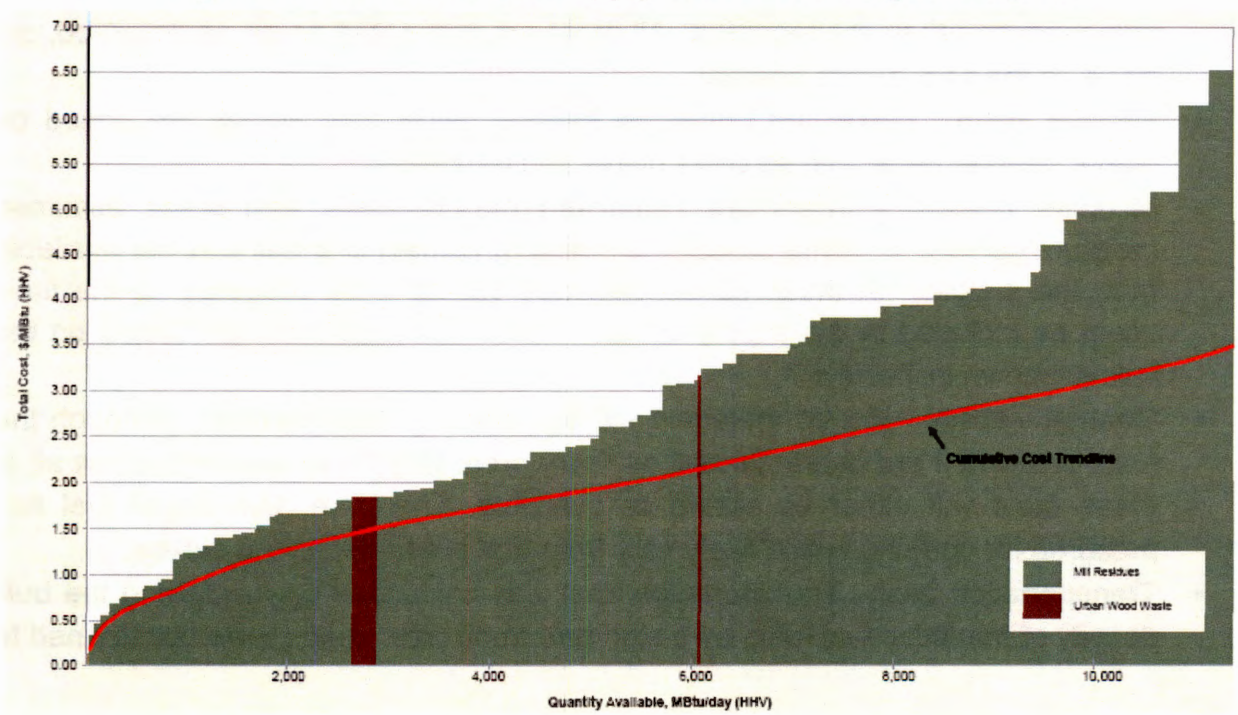
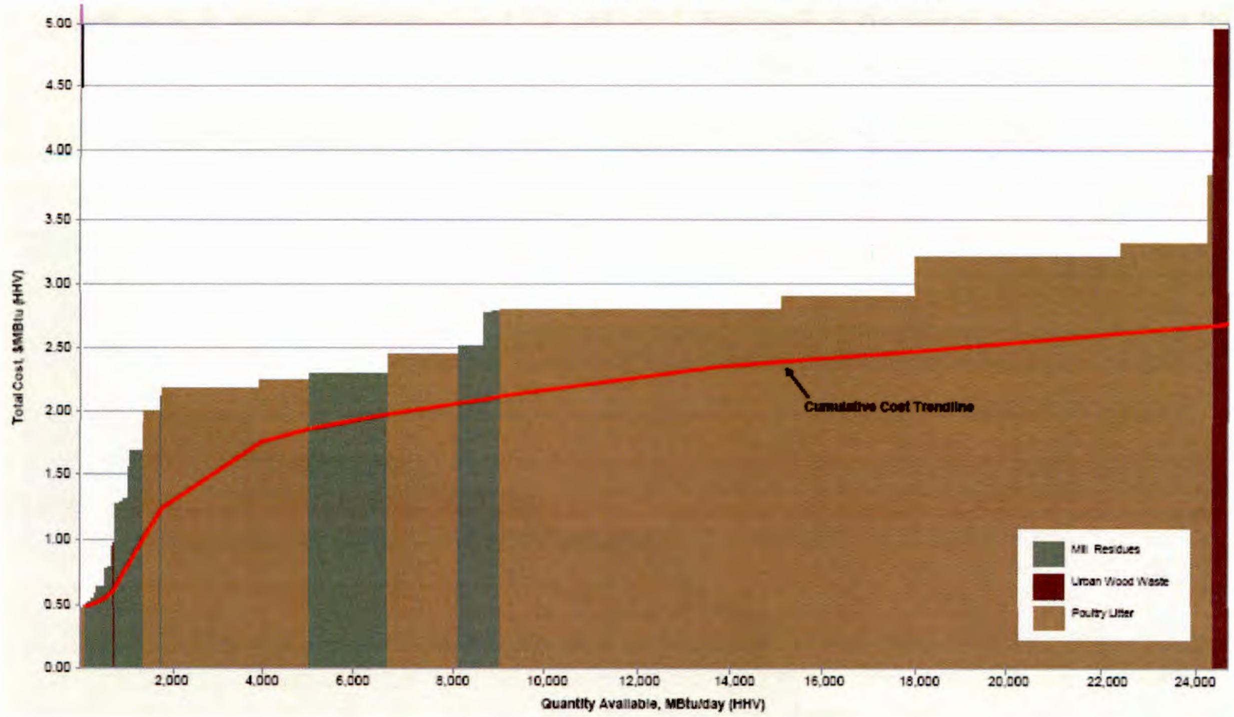


Figure 5.4 Biomass Fuel Supply Curve for Monett Region



Assumptions and Conditions

A number of assumptions were made to generate these curves. The assumptions include the following:

- Delivered cost - Costs are based on estimated or quoted prices provided by each individual supplier. Some suppliers choose not to disclose the current compensation they are receiving. All costs are presented on an as-delivered, dry basis, to the best extent possible.
- Heating value - Costs are based on heating value. The curves are based on higher heating value with all costs presented as $/MBtu.
- Moisture content - Costs are calculated on dry basis with some assumed moisture content. In some cases, the moisture content of a fuel was not available from the supplier. In these cases, moisture values were assumed so the fuels could be included in the supply curves. These assumptions were based on the values shown in Table 5.7.
- Material viability - Not all materials will be viable to meet demand. Although the fuels presented are characterized as "very promising," it is certain that not all of these fuels will either be viable or available. Therefore, the actual fuel mix procured for co-firing would likely vary from that presented in the curves.
- Transportation cost - Transportation cost was calculated by multiplying the bulk density of the individual fuels by a standard truck size. Loads were constrained to

a maximum of 24 tons, which is a typical load limit in the U.S. Hauling costs were obtained from several sources during the inventory.

- Forest residues estimated - The cost and quantity of forest residues has been estimated using the assumptions set forth in this report. Based on previous assessments, approximately 300 tons per day of material will be available. An average delivery distance of 50 miles was used.

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 more available resources. For the co-firing project identified in the St. Louis region, the project was sized based on utilization of half the resource identified in the detailed assessment.

A 28.8 MW co-firing project 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 5.8 and Table 5.9 list primary characteristics of the identified projects. More detailed information can be found in Chapter 5 – Appendix B.

Table 5.8 Biomass Resource Fuel Requirements[15]

Project Location	Net Capacity (MW)	Needed Fuel Supply (Mbtu/day)	Available Fuel Supply (Mbtu/day)	Net Plant Heat Rate (Btu/kWh)	Capacity Factor (%)
St. Louis (co-firing)	28.8	6,300	12,600	10,125	85%
Ellington (standalone)	13.5	3,767	13,000	14,500	80%
Monett (standalone)	29.5	8,233	24,700	14,500	80%

Table 5.9 Potential Biomass Resources[16]

Resource Option	Renewable Resource	Operations Mode	Total Project Cost - Includes Owners Cost, $/kW	Assumed Fuel Type / Source	First Year Fuel Cost, $/MBtu	Annual MWh's output	Forced Outage Rate, percentage	LCOE, ¢/kWh
Co-firing (St. Louis Region)	Biomass	Baseload	$950	Wood	$2.66	214,445	9%	$5.90
Wood-fired Standalone (Ellington Region)	Biomass	Baseload	$8,510	Wood	$2.98	94,608	9%	$29.02
Poultry-litter Standalone (Monett Region)	Biomass	Baseload	$6,190	Wood/Litter	$2.69	207,437	9%	$20.68

[15] 4 CSR 240-22.040(1)(A); 4 CSR 240-22.040(1)(B); 4 CSR 240-22.040(1)(J)
[16] 4 CSR 240-22.040(1)(A); 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(I)

5.3.4.2 Assessment of Future Biomass Fuel

In addition to the existing biomass resource assessment, Black & Veatch also considered biomass resources that are not developed at this time, but may have more potential in the longer term of 5 to 10 years. These resources include forest thinnings, agricultural residues, and energy crops such as switchgrass and miscanthus. For each of these resources, Black & Veatch has quantified the available potential and fuel properties, characterized the methods of harvesting and collection, and identified the current barriers to widespread utilization of these resources. However, these resources have not been included in the fuel supply curves developed in the previous section.

Key findings and conclusions regarding the potential of forest thinnings, agricultural residues, and energy crops in Missouri include the following:

Forest Thinnings

There are considerable forested lands in southern Missouri. These forested lands are largely overstocked, and thinning of these lands would be beneficial to the health of the timber stands in these areas. According to one somewhat conservative estimate, forest thinnings could yield an average of 9.5 green tons per acre across southern Missouri. (It should be noted, however, that a given acre can only be thinned once every 10 to 20 years.) Based on harvesting rates and equipment ownership costs projected by researchers at Auburn University, Black & Veatch estimates the delivered cost of forest thinnings to be $32/ton ($3.75/MBtu). This includes the cost of equipment, labor, stumpage, and transporting the chipped thinnings up to 40 miles. It is feasible that a significant thinning harvesting network could be established within 18 to 24 months to support a constructed bioenergy facility. To further facilitate the development of this supply chain, Missouri Forest Product Association (MFPA) has applied to Missouri Agricultural and Small Business Development Authority (MASBDA) for funding to initiate development of a producer-owned woody biomass cooperative to supply fuels to biomass energy projects. In the next 2 to 5 years, forest thinnings appear to have potential as fuel for biomass-derived power, either for a co-firing project or a small (i.e., 25 MW) standalone project. These projects are likely to be located in the southern or southwest potions of Ameren Missouri's service territory.

Agricultural Residues

Agricultural residues are present in significant quantities across northern Missouri and in counties bordering the Mississippi River. However, these resources are more dispersed than forest thinnings, particularly as only a portion of the available residues can be collected. The cost and logistics of collection and transportation remain significant barriers to more widespread utilization. Pelletization of agricultural residues, currently being demonstrated by Show Me Energy Cooperative (SMEC), is considered to be the most viable method for utilization of agricultural residues in Missouri. This supply model reduces the number of suppliers with which an electrical generating facility must coordinate and provides a product with a relatively high heating value (i.e., 8,000 Btu/lb) that requires little, if any, processing following delivery to the plant. SMEC is currently ramping up activities at their 100,000 ton per year facility in western Missouri, and it is expected that it would be 3 to 5 years before the cooperative operates a 100,000 ton per year facility nearer to Ameren Missouri's service territory. Such a facility could provide approximately 10 to 12 MW of biomass-derived generation at a standalone facility or 14 to 16 MW of biomass-derived generation when co-fired at an existing facility. The heating value of the product produced by SMEC is higher than that of forest thinnings, however, SMEC is unable to deliver at a price competitive to forest thinnings. A competitive price would need to be approximately $60/ton.

Energy Crops

There is a large potential for production of energy crops such as switchgrass and giant miscanthus in north central Missouri. However, there is little current production due to the high costs of production and transportation and the lack of a market for the crops in the region. Given the limited supply of existing energy crops and the high costs of processing baled grasses, the most viable pathway for the utilization of energy crops for electricity generation in Missouri in the next 5 to 10 years may be as a portion of the feed stream to a biomass pelletization process.

5.3.5 Potential Solar Resources

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

The solar resource is characterized as direct normal insolation (DNI) or global insolation. DNI is used by concentrating solar technologies, and global insolation is used by solar photovoltaic systems. On a horizontal surface, the global insolation is often called the total horizontal insolation (THI). There can be total and global insolation on a tilted surface as well.

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. On a horizontal surface, the global insolation is often called the total horizontal insolation (THI). A map of the THI for the U.S. is shown in Figure 5.5. 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 THI value of 4.24 kWh/m^2-day. Figure 5.6 shows the monthly average THI for St. Louis.

Figure 5.5 Total Horizontal Insolation (THI) Map if the US

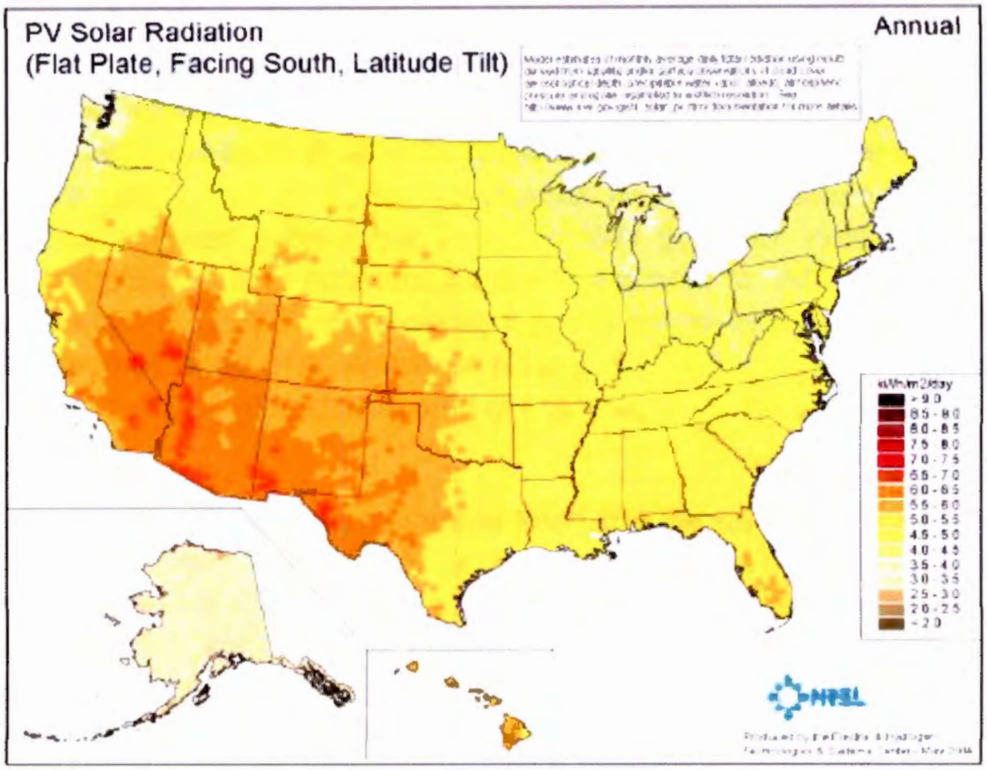
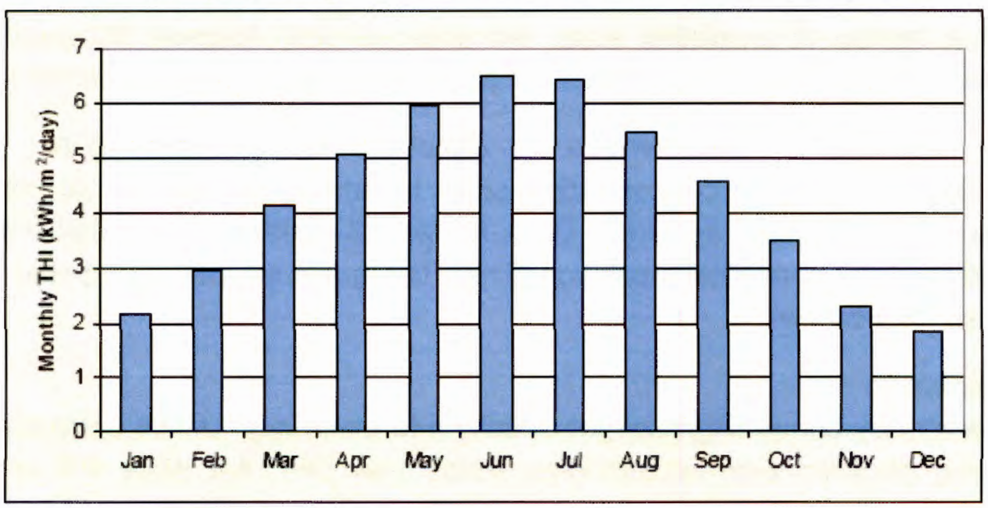


Figure 5.6 Monthly Average Total Horizontal Insolation (THI) for St. Louis



Flat Plate Photovoltaics

Traditional wisdom in the solar industry has been that solar photovoltaic (PV) systems are appropriate for small distributed applications, and that solar thermal systems are more cost effective for large, central station applications. In recent years PV systems as large as 60 MW have been installed in Europe. A 15 MW system was installed at Nellis Air Force Base in Nevada, the 10 MW El Dorado Solar system was installed near

Boulder City, Nevada, and an 8.2 MW system was installed near Alamosa, Colorado. Worldwide, there are more than two dozen PV installations over 10 MW and more than 600 systems that are 1 MW or greater in capacity. Furthermore, central station PV systems are being bid in response to utility requests for proposals.

Technology Overview

PV systems convert sunlight directly into electricity. The conversion of sunlight into electricity is known as the photovoltaic effect, and the materials and processes involved are very similar to semiconductors. The power produced depends on the material involved, the intensity of the solar radiation incident on the cell, and the cell temperature. Single or polycrystalline silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are sliced into thin cell-sized wafers. The cost of the crystalline material is significant. The production of polycrystalline cells, which are made from cast material rather than grown crystals, can cut material costs with some reduction in cell efficiency. Thin film modules, which are significantly less expensive but not as efficient, are also being used for large scale solar applications.

A PV system has two critical components: solar modules and inverters. The other important components include mounting system and hardware, disconnect switches, meters, and monitoring equipment. Solar modules convert sunlight directly into electricity, and the inverter converts the direct current (dc) electricity from the modules into alternating current (ac) electricity used by the electric grid. These two critical components are discussed in more detail in the following subsections.

Solar Modules

Solar modules are made up of individual solar cells connected electrically in series. The cells are then encased with an encapsulant and mounted in a rectangular frame sandwiched behind a glass that is designed to withstand hail and other shocks. The traditional cell material for solar modules is crystalline silicon. Crystalline silicon, either single crystal or poly crystal, is a well understood technology with many years of operating data. Single crystalline modules tend to be slightly more efficient (up to 20 percent) with increased cost, while poly crystalline is slightly less efficient (around 14 percent) with lower costs. Crystalline silicon modules have a design life of 30 to 40 years. There have been systems operating for over 20 years, and current modules have higher quality glass and encapsulant than the older models. Solar modules degrade over time, usually about 1 percent per year.

Another type of solar cell is thin film, made from layers of semiconductor materials only a few micrometers thick. In addition to reducing material costs, thin film makes applications more flexible, as it can be integrated into roofing tiles or windows. Thin film cells significantly reduce cost per unit area, but have lower efficiency. Types of thin film include amorphous silicon with the longest operating history, cadmium telluride (CdTe), and copper indium gallium selenide (CIGS), which is under development. Typical efficiencies for amorphous silicon thin film modules are in the 6 to 8 percent range. CdTe and CIGS producers look to achieve efficiencies above 10 percent. Cost, not efficiency, is the main driver for the thin film market. Thin film modules have similar warranties to crystalline modules, but due to the limited operating experience there is uncertainty about their degradation.

Some manufacturers combine crystalline silicon and amorphous silicon cells to create high efficiency cells. Sanyo's Heterojunction with Intrinsic Thin Layer (HIT) modules are most well-known. These combine a mono-crystalline wafer with a layer of amorphous silicon on either side. The modules have efficiencies between 15 and 17 percent and have better temperature characteristics than typical crystalline modules.

Inverters

Inverters are the other key component of solar systems. In solar systems, inverters perform several functions including the following:

- Convert the dc electricity from the modules to ac electricity used by the grid.
- Perform maximum power point tracking (MPPT) to ensure each string is performing at its maximum power.
- Step up voltage to grid voltage, generally 480 volts for larger commercial inverters and 120 or 240 volts for residential inverters.
- Provide a data interface for monitoring systems to log and track generation.
- Provide "anti-islanding" protection per IEEE standard 1547, which ensures the inverter will disconnect from the grid if it senses the loss of grid power.

Inverters are not 100 percent efficient at converting power. Losses are generally either through heat dissipation or internal power needs for fans and electronics. Most inverters are about 95 percent efficient. The efficiency curve of inverters is least efficient at part load, most efficient at 80 percent load, and slightly less efficient at full load. Inverters will slowly lose efficiency over time as capacitors wear.

Inverter life has been a difficult issue for the solar industry. Many early inverters had significant failures and poor performance. The industry has now matured greatly, and experience with large systems in Europe has helped improve quality. To date, most inverters have been assumed to have a 10 year lifespan, requiring full replacement. Larger inverters (greater than 50 kW) may be rebuilt or repaired and continue to run for 20 to 25 years. Fans, major power transistors, and capacitors would be replaced in a major overhaul. Black & Veatch forecasts a major overhaul of inverter components at year 15, which would cost roughly half of the initial cost of the inverter, in nominal dollars.

Inverters, unlike solar modules, have significant economies of scale. Commercial and residential systems use the same types and sizes of modules, but commercial systems use much larger inverters. Commercial scale inverters will typically cost between 20 and 30 cents per watt, while residential systems can cost as much as 70 cents per watt. Black & Veatch does not foresee major cost reductions in commercial inverters in the coming years.

Mounting Systems

Utility scale PV installations are ground mounted with a fixed orientation often at latitude tilt or on one or two axis trackers. Flat plate PV panels receive the most insolation, and therefore produce the most power, when directly facing the sun. If panels are fixed in their mounting, the most production over a year is obtained by facing the panels south and tilting them at the site's latitude.

Many system designers, however, wish to maximize production in summer months when power prices are higher. For maximum summer production, latitude minus 15 degrees (or roughly 20 degrees in North America) is optimal. This tilt will produce 6 percent more than latitude tilt in the summer months (May through September) and about 2 percent less over a full year. Laying panels flat will produce roughly the same as this in the summer months, but about 11 percent less annually.

There are also single axis and two axis tracking systems. As the name suggests, single axis tracking systems will follow the sun in one direction (i.e. east to west) to increase insolation. One axis tracking flat plate PV systems produce roughly 20 percent more energy than latitude tilt fixed panels and 35 percent more in summer months.

Two axis tracking systems will adjust both east to west and north to south so that the panels are always directly facing the sun. Two axis flat plate PV systems produce approximately 30 percent more than fixed panels and 40 percent more in summer months. This performance comes at a cost, however, as these systems use more land area and are much more costly to install and maintain. These trackers are commonly used in off-grid locations where maximum power is required throughout the year.

Solar PV systems cost $6,000/kW with a capacity factor of approximately 21% in the Ameren Missouri region[17]. It is noteworthy that solar capital costs are expected to decline in real dollars; therefore, solar capital costs were escalated at 1% while inflation is expected to be 3%. Chapter 5 – Appendix B contains more detailed information.

5.3.6 Potential Wind Resources

For resource planning purposes Ameren Missouri characterized a generic wind resource in the Midwest (North Dakota, South Dakota, Nebraska, Kansas, Oklahoma,

[17] 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(J)

Minnesota, Iowa, Missouri, Wisconsin, Illinois, and Indiana). A capacity factor of 37.5% was estimated using the latest wind potential estimates from the National Renewable Energy Laboratory (NREL) for the Midwest at an 80 meter hub height[18]. The generic wind overnight project cost is expected to be $2,000/kW, including owner's cost. For modeling purposes no additional transmission costs were included[19]. Chapter 6 includes a description of the transmission build-out assumption that would eliminate any transmission obstacles for new wind resources. The levelized cost of wind is estimated to be 10.81 cents/kWh. Chapter 5 – Appendix B contains more detailed information.

Figure 5.7 Wind Map of U.S.

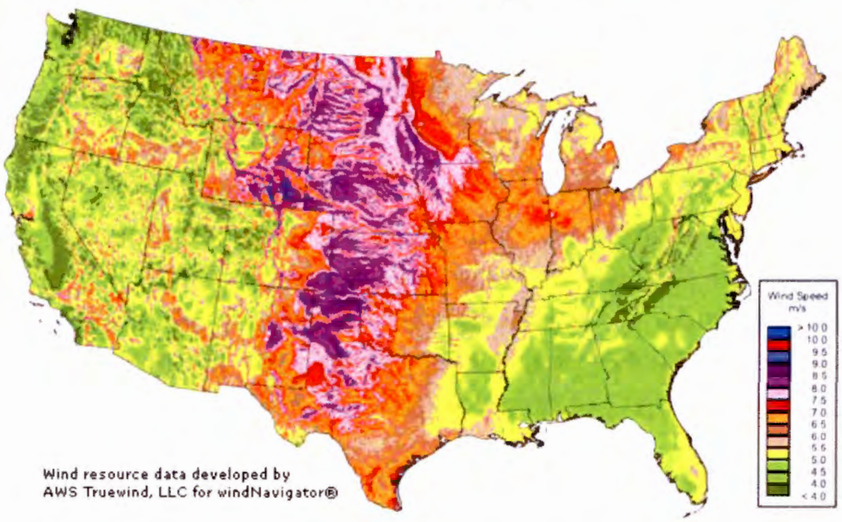
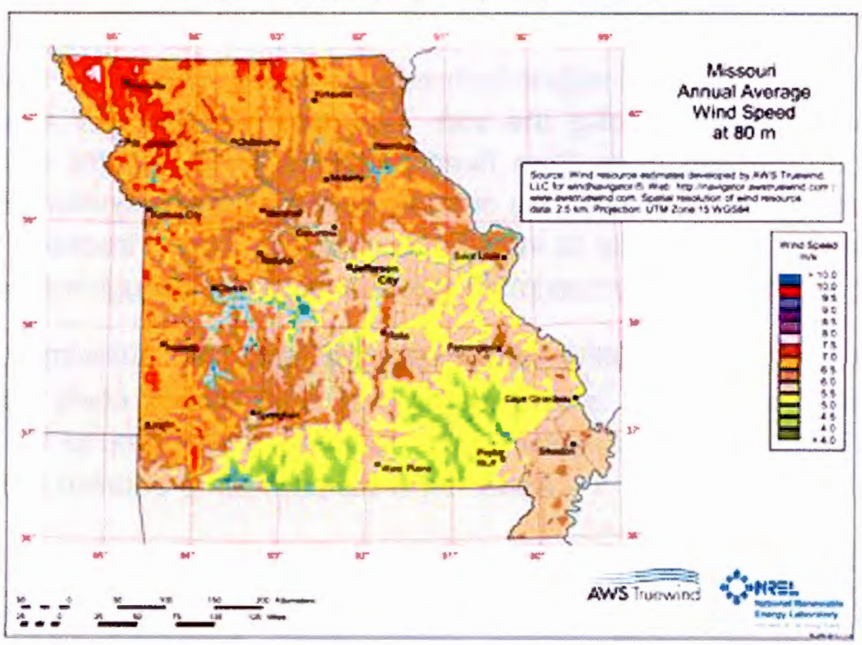


Figure 5.8 Wind Map of Missouri



[18] EO-2007-0409 – Stipulation and Agreement #14
[19] 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(J)

Wind is not generated uniformly throughout the day, month, or year. The spring and fall months tend to be high production periods, while the summer months generally produce the least amount of energy. The daily generating cycle in the summer months is generally higher during the early morning through 8 a.m., and then from roughly 8 p.m. through midnight. The daily generation cycle tends to be more uniform the rest of the year. Wind is considered to be an energy resource with limited regulatory capacity value – currently 8 percent of the nameplate rating is allowed by MISO.

With a levelized cost of energy of 10.81 cents/kWh, wind is competitive with other thermal resources identified in Chapter 4. However, as described in Chapter 9, alternative resource plans are constructed to meet capacity needs throughout the planning horizon. It would be impractical to use wind as a capacity resource since only 8 percent of the nameplate rating would count. For example, to meet a 300 MW capacity shortfall Ameren Missouri would need 3,750 MW of wind. To incorporate wind as a major supply-side option for alternative resource plans, Ameren Missouri paired wind resources with simple cycle combustion turbines. These two resources are complementary since wind offers energy output while the combustion turbines offer peaking capacity. The combination of 800 MW of wind and 346 MW of combustion turbines provides 410 MW of peaking capacity, which is roughly consistent with the size of other thermal resources being considered. The levelized cost of energy for the combined resource is 12.44 cents/kwh, which is still competitive with the other resources.

The current most prevalent hub height installations in the U.S. are at 80 meters but, there is growing interest in 100 meter installations.[20] Currently there are plans for 100 meter installations in Ohio along with potential for others throughout the U.S. After consulting with the renewable team at Ameren the general consensus is that capacity factors would increase from 10-20% moving from 80 to 100 meters in hub height. This increase in hub height is estimated to increase overall installation costs approximately 5%. Given this set of expectations, a 100 meter hub height installation would cause the LCOE to move from as low as 9.47 to as high as 10.26. Given that our base wind assumption for LCOE is 10.81, this range of potential costs indicates that any potential project should incorporate a complete site-specific evaluation of different tower heights to determine which will provide the greatest value.

There are several complicating factors when moving from 80 meters to 100 meters that make the decision to move to the higher installations more than just strictly an economic analysis decision. There are potentially greater hurdles to overcome with regards to permitting the larger towers that include local opposition due to visual appeal, FAA limitations at the higher hub heights, and even issues regarding potential bird and bat

[20] EO-2007-0409 – Stipulation and Agreement #14

migratory path limitations. Additionally, the equipment to install the larger towers is limited and can potentially affect the timing and/or cost of any installation.

Ameren Missouri used 3 TIER's software package called FirstLook to evaluate wind potential in the Ameren service territory. The anticipated capacity factor at the sites was considerably lower than non-Ameren sites thus eliminating them from further consideration.

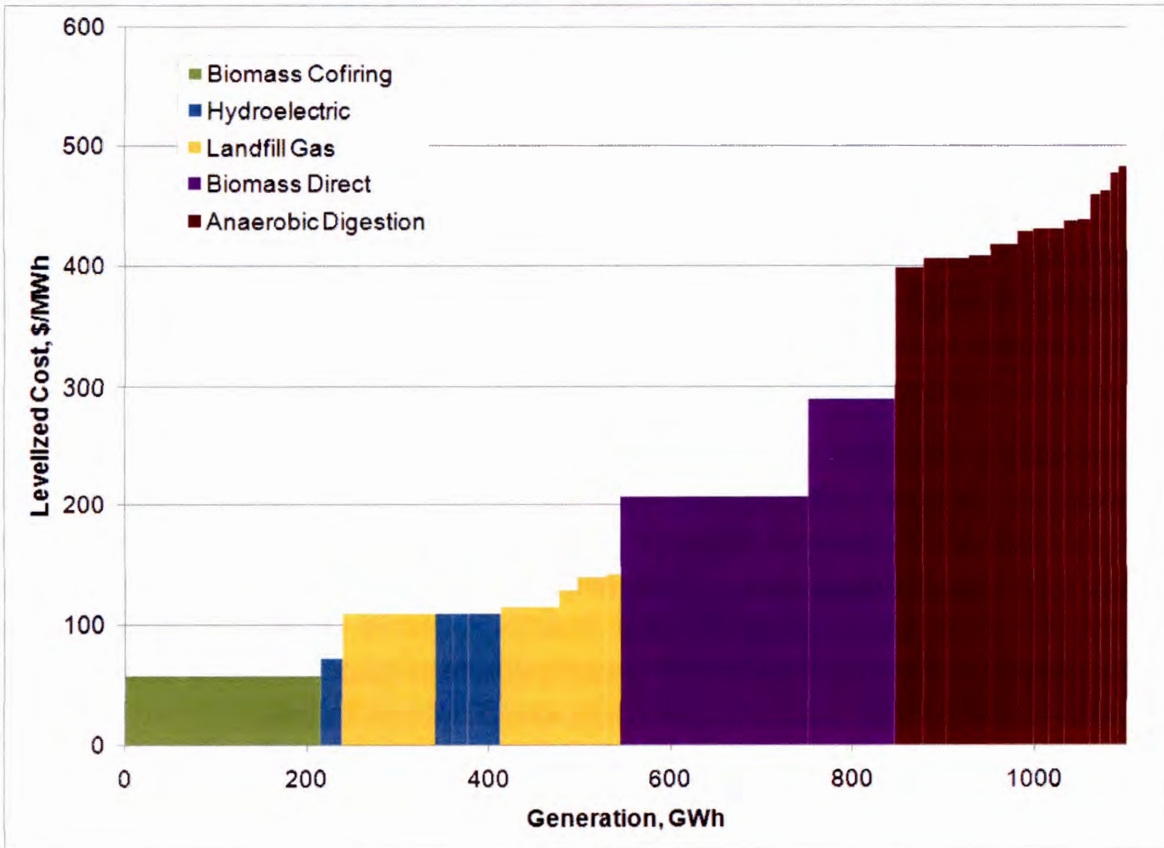
5.4 Renewable Supply

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 5.7 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).

Figure 5.9 indicates that there is approximately 1,100 GWh of renewable energy potential. However many of those projects are costly, namely the projects over $200/MWh. Excluding the higher cost projects would leave approximately 540 GWh of renewable energy potential. For comparison, Ameren Missouri expects to need over 500 GWh of new renewable energy in 2019 and almost 4,500 GWh in 2021 to meet the renewable energy requirements of the Missouri RES.

Figure 5.9 Ameren Missouri Renewable Energy Supply Curve[21]



It is important to note that Figure 5.9 does not include wind resources, which has a levelized cost of $108/MWh. Based on NREL's wind resource data there is over 433,000 MW of wind potential in the Midwest which would be over 1.4 million GWh of energy potential at an average capacity factor of 37.5%. With so much potential it was assumed that enough wind would be available to meet Ameren Missouri's renewable energy requirements. Transmission constraints may be a limiting factor for wind potential, but the IRP analysis assumed a transmission system build-out that removes barriers to the wind potential needed to meet Ameren Missouri renewable energy requirements. A discussion of the transmission system build-out that supports expanded renewable energy can be found in Chapter 6.

Biomass co-firing is also a cost-effective renewable resource with relatively large potential. Figure 5.9 only includes 28.8 MW of co-firing at an existing Ameren Missouri power plant. However, the

Table 5.10 Biomass Co-firing Fuel Needs

Fuel Needs (MMBtu/Day)			
Cofiring Percent	**1%**	**5%**	**10%**
Labadie	4,900	24,600	49,100
Sioux	2,000	9,800	19,600
Rush Island	2,400	11,800	23,700
Total	9,300	46,200	92,400

[21] 4 CSR 240-22.040(2)(A);

potential for co-firing is much greater without considering the fuel supply constraints. Black and Veatch estimated the amount of co-firing based on the assumption that half of the potential fuel supply would be available, or about 6,300 MMBtu/day. Table 5.10 shows the fuel demand for higher levels of biomass co-firing far exceed the identified supply. Significant advancements in the fuel supply chain will be necessary for biomass co-firing to be a significant portion of Ameren Missouri's renewable portfolio.

Figure 5.9 can also be misleading as it shows biomass co-firing is the least-cost renewable resource. However, 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, hydro, and landfill gas are more cost-effective resources than biomass co-firing to meet renewable requirements.

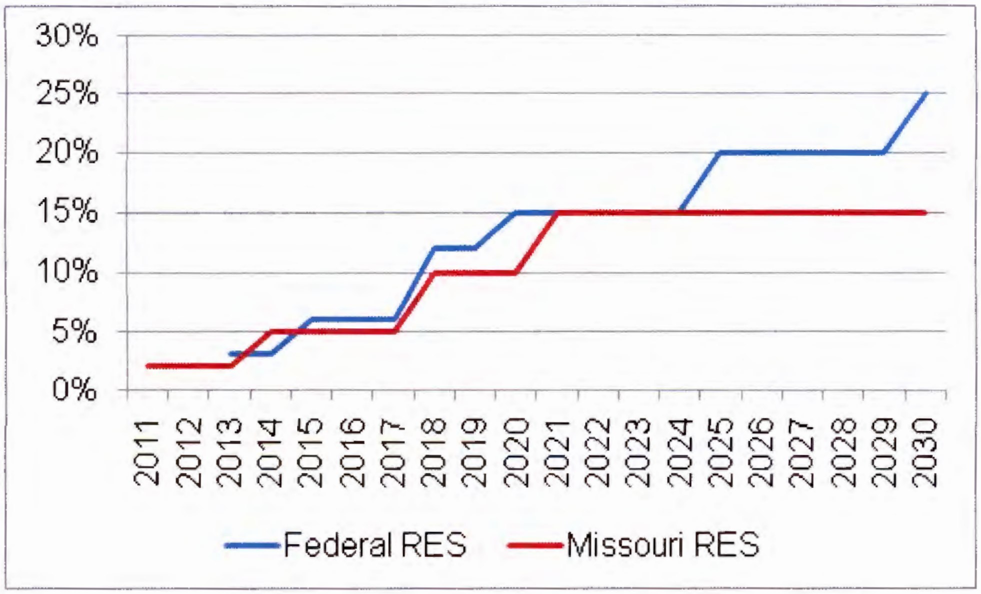
After discussions with Ameren Fuels and Services organization it was determined that there were no pending potential long-term power purchases for consideration at the time of the analysis[22]. Ameren Missouri will continue to evaluate bids from third-party developers as opportunities arise. Evaluation 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.

5.5 Renewable Energy Standards

The IRP analysis included two potential Renewable Energy Standards (RES) that could affect the renewable strategy that Ameren Missouri would pursue and in turn affect the need for other resources. The first RES involved the recently adopted Missouri voter initiative which requires that utilities acquire renewable energy equal to an increasing percentage of their retail electric sales, subject to a 1% rate cap. In addition to the state RES, a Federal renewable standard was modeled that imposed a different set of increasing renewable energy obligations with different types of resources that would be eligible to meet the requirements. Figure 5.10 shows a comparison of the state and Federal renewable requirements.

[22] 4 CSR 240-22.040(5)(A-G)

Figure 5.10 Comparison of Missouri and Federal RES



RES Modeling

A spreadsheet model was developed to model the RES requirements. Although 10 planning scenarios for load are being used for the IRP analysis, the probability weighted average was used for the development of the RES compliance portfolio. Modeling a portfolio for each scenario would not have been practical and the portfolios that are developed were analyzed later in all ten scenarios once they are incorporated into the resource plans. Furthermore, load variations would not have produced significantly different Missouri RES portfolios given the limiting effects of the 1% rate cap.

The rate cap limitations were modeled relative to a plan with no additional renewables. For this plan Ameren Missouri used the resource plan that included Realistic Achievable Potential (RAP), Meramec retired in 2022, and Noranda continuing to represent a reasonable least-cost benchmark with no additional renewables. In this resource plan, RAP adequately meets future capacity needs. The revenue requirements from that resource plan were simulated in MIDAS and the probability weighted average served as the rate impact limit benchmark. The retail sales forecast, which was the base for the renewable energy requirements, was the probability weighted average of the forecasts developed in Chapter 3.

The next step in developing RES compliant portfolios was to take inventory of existing Ameren Missouri resources that are eligible to meet renewable requirements. For the Missouri RES several resources qualify including: Ameren Missouri's wind purchase power agreement, Keokuk (which is a made up of small hydro units and upgrades), and the pending completion of a landfill gas project. Ameren Missouri also included the incremental output of some upgrades to its Osage facility. It is noteworthy that the Osage upgrades require further review and certification by MoDNR before becoming a qualified resource under the Missouri RES. For the federal requirements the output of Callaway, output from Taum Sauk, and non-qualified output of Osage and Keokuk were subtracted from the load forecast to reduce the base level of renewable energy requirements. A three year bank was also included for qualified Ameren Missouri renewable resources under both renewable standards.

After including existing renewable resources it was evident that Ameren Missouri would be compliant with the non-solar requirements throughout the implementation period. Furthermore it was evident that the volume of renewable resources needed could not be met with the resources initially identified by Black and Veatch's potential study. Most of the projects in the study were small and opportunistic in nature. For compliance purposes wind was assumed to be the resource that met the majority of the renewable energy needs. As a base assumption, Ameren's landfill gas project was expected to be in-service starting in 2012 with 5MW expansions in both 2020 and 2025. Since the other renewable projects were relatively small or expensive they were not modeled in the long-term compliance plan, but Ameren Missouri will be evaluating individual projects as appropriate. Although wind is an attractive renewable resource because of its economics and potential, biomass co-firing is also an attractive alternative. For modeling purposes new renewables were limited to either wind or biomass co-firing (up to 10% for Sioux and 5% at Labadie and Rush Island).

For solar compliance Ameren Missouri included Renewable Energy Credit (REC) purchases for the first 5 years then modeled the addition of utility scale solar resources.

To model the effects of adding renewables to the revenue requirement Ameren Missouri considered the net cost of additional renewable resources. The net cost of a project included the new resource costs (capital and O&M) and the project benefits (energy and capacity). In the case of the Missouri RES, if the cumulative net cost in any year exceeded the 1% cumulative rate impact (measured from the benchmark resource plan) then both the non-solar and solar resources were reduced to meet the rate limit. Once the rate cap was reached additional resources could be added because of natural increases in the benchmark revenue requirements and any increasing benefits from prior RES renewable projects. The 4% cap of the federal RES did not limit the addition of renewable resources while the 1% cumulative rate impact in the Missouri RES significantly limited the addition of renewable resources.

As explained in Chapter 9, Alternative resource plans include several attributes that combine to define a unique resource plan. Three of those attributes significantly impact the amount of renewables included in any given alternative resource plan. First is the renewable portfolio of either Missouri or Federal. However, as these requirements were modeled it was apparent that both the status of Noranda and the aggressiveness of the DSM portfolio (the other two relevant attributes) significantly impact the renewable energy requirements. Therefore, there were 16 unique renewable portfolios developed, which are combinations of renewables requirements (2, federal or state), DSM portfolios (4; None, Low Risk, RAP, or MAP), and Noranda's status (2, expires or continues).

5.5.1 Missouri RES

Ameren Missouri modeled the requirements of the Missouri RES using the previously mentioned spreadsheet model. The implementation rules for the Missouri RES were under development during this analysis, so Ameren Missouri attempted to model a reasonable representation of the RES based on its assessment of the draft rules. The Missouri RES includes a 1% rate impact cap. Eligible renewable resources are defined by the Missouri Department of Natural Resources and include hydro units less than 10MW, landfill gas, biomass co-firing, wind, and solar among others. The Missouri RES also includes a requirement that 2% of the RES requirements are met by solar resources.

Missouri RES Results

Figure 5.11 shows Ameren Missouri's renewable position compared to the RES requirements. Although there were 8 different Missouri renewable portfolios, Figure 5.11 represents the Missouri RES compliant portfolio that includes the Low Risk DSM portfolio and Noranda continuing as a retail customer. It is evident that the 1% rate cap significantly limits the amount of new renewables. Figure 5.11 also shows Ameren Missouri's existing non-solar renewable resources exceed the RES requirements initially and build a renewable credit bank that delays the need for additional non-solar renewable resources. At the end of the planning horizon Ameren Missouri's non-renewable energy is about 5% of the retail load compared to the 15% RES requirement. In all 8 portfolios the 1% rate cap is reached in 2019, which is the first year non-solar resources are needed. The addition of solar resource before 2019 depletes much of the 1% rate cap funds. Table 5.11 and Table 5.12 show the data in tabular format.

Figure 5.11 Ameren Missouri Renewable Resource Position

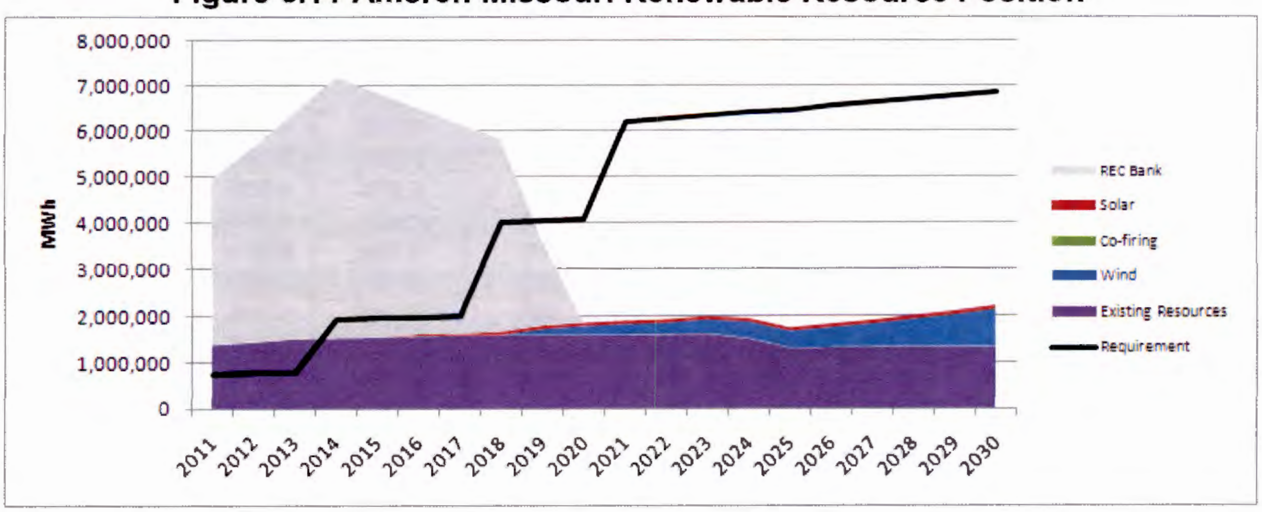


Table 5.11 Non-Solar Renewable Position

Year	Retail Load Base GWh	Non-Solar GWh Req.	Existing Resources	New Wind Energy	New Landfill Gas Energy^	Non-Solar Renewable Need (Short)/Long	Actual Non-Solar Renewable Percent*	Non-Solar RES Req.
2011	37,623	737	1,376	0	0	4,207	1.96%	1.96%
2012	38,280	750	1,376	0	60	4,892	1.96%	1.96%
2013	38,468	754	1,390	0	123	5,651	1.96%	1.96%
2014	38,718	1,897	1,403	0	123	5,280	3.94%	4.90%
2015	39,020	1,912	1,416	0	123	4,908	3.95%	4.90%
2016	39,432	1,932	1,443	0	123	4,542	3.97%	4.90%
2017	39,600	1,940	1,456	0	123	4,181	3.99%	4.90%
2018	39,929	3,913	1,456	0	123	1,847	3.96%	9.80%
2019	40,388	3,958	1,456	129	123	(402)	4.23%	9.80%
2020	40,936	4,012	1,456	195	123	(2,237)	4.33%	9.80%
2021	41,259	6,065	1,456	235	123	(4,251)	4.40%	14.70%
2022	41,716	6,132	1,456	241	143	(4,292)	4.41%	14.70%
2023	42,183	6,201	1,456	298	153	(4,294)	4.52%	14.70%
2024	42,779	6,288	1,343	351	163	(4,432)	4.34%	14.70%
2025	43,135	6,341	1,120	351	182	(4,687)	3.83%	14.70%
2026	43,637	6,415	1,120	412	192	(4,691)	3.95%	14.70%
2027	44,155	6,491	1,120	475	202	(4,693)	4.07%	14.70%
2028	44,817	6,588	1,120	561	205	(4,701)	4.21%	14.70%
2029	45,224	6,648	1,120	642	205	(4,680)	4.35%	14.70%
2030	45,773	6,729	1,120	737	205	(4,666)	4.51%	14.70%

*Excludes Banked RECs
^Includes 1.25 Adder

Table 5.12 Solar Renewable Position

Year	Retail Load Base GWh	Solar GWh Req.	New Solar Energy†	Solar Renewable Need (Short)/Long	Actual Solar Percent	Solar Req.
2011	37,623	15	15	0	0.04%	0.04%
2012	38,280	15	15	0	0.04%	0.04%
2013	38,468	15	15	0	0.04%	0.04%
2014	38,718	39	39	0	0.10%	0.10%
2015	39,020	39	39	0	0.10%	0.10%
2016	39,432	39	39	0	0.10%	0.10%
2017	39,600	40	40	0	0.10%	0.10%
2018	39,929	80	80	0	0.20%	0.20%
2019	40,388	81	80	(1)	0.20%	0.20%
2020	40,936	82	80	(2)	0.20%	0.20%
2021	41,259	124	81	(43)	0.20%	0.30%
2022	41,716	125	81	(45)	0.19%	0.30%
2023	42,183	127	81	(45)	0.19%	0.30%
2024	42,779	128	82	(47)	0.19%	0.30%
2025	43,135	129	82	(48)	0.19%	0.30%
2026	43,637	131	82	(49)	0.19%	0.30%
2027	44,155	132	83	(49)	0.19%	0.30%
2028	44,817	134	84	(50)	0.19%	0.30%
2029	45,224	136	85	(51)	0.19%	0.30%
2030	45,773	137	86	(51)	0.19%	0.30%

†Includes RECs for the first 5 years

Although there are 8 unique Missouri RES portfolios, the results for each portfolio are similar as each is constrained by the rate cap. Figure 5.12 shows the amount of solar resources that were added while Figure 5.13 shows the amount of wind resources that were added. More solar resources are added with less energy efficiency since retail sales are greater. Those additional solar resources cost more and therefore cause Ameren Missouri to reach the 1% rate cap faster, reducing the amount of wind that can be added later in the planning horizon.

Figure 5.12 Solar Resources Added for Missouri RES

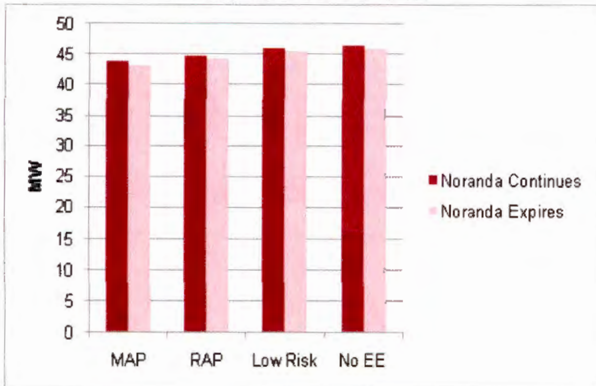


Figure 5.13 Wind Resources Added for Missouri RES

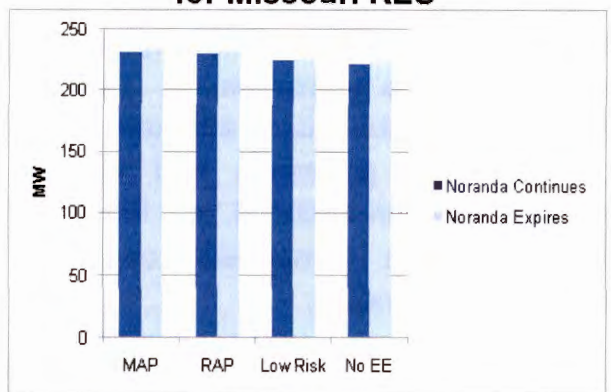
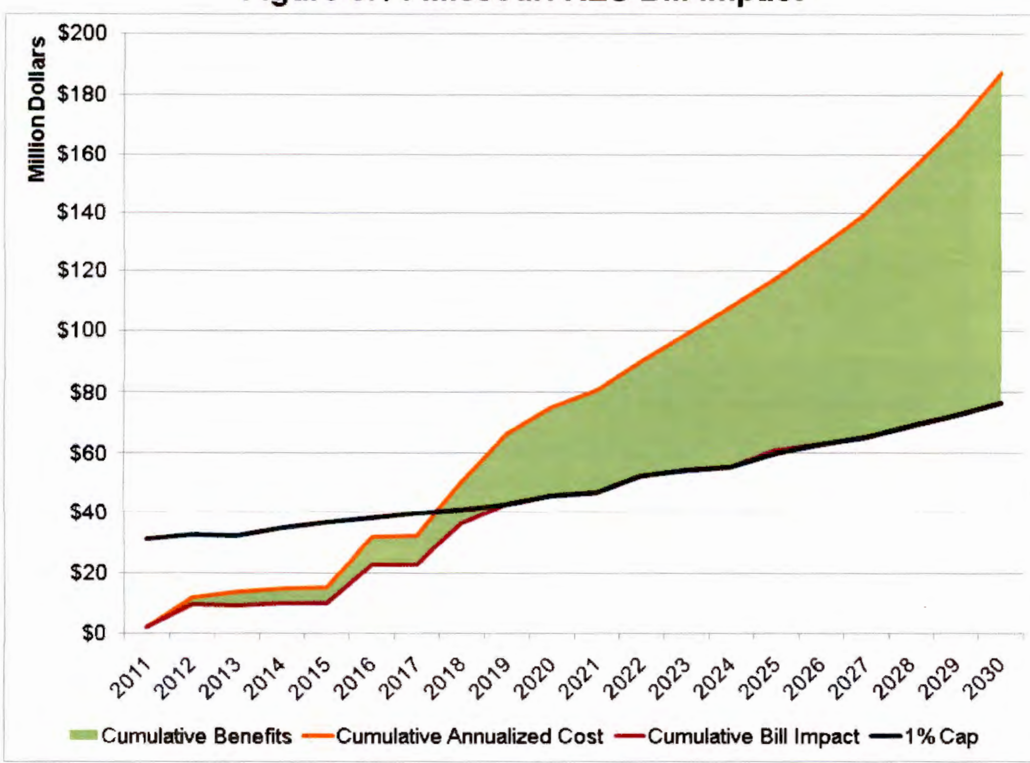


Figure 5.14 shows the cumulative rate impact throughout the planning horizon. The immediate rate impacts are caused by the solar needs. The rate cap is not reached until 2019 when additional non-solar resources are needed.

Figure 5.14 Missouri RES Bill Impact



5.5.2 Federal RES

In order to provide a more complete view of the risks and opportunities associated with RES requirements, Ameren Missouri analyzed a federal RES. To represent a Federal RES, Ameren Missouri compared several proposed legislative packages. The requirements modeled included a hybrid of the various recent proposals as a reasonable approximation. Table 5.13 contains the major attributes of different RES proposals and what Ameren Missouri modeled, and Figure 5.15 shows a comparison of the energy requirements.

Figure 5.15 Comparison of Federal Renewable Requirements

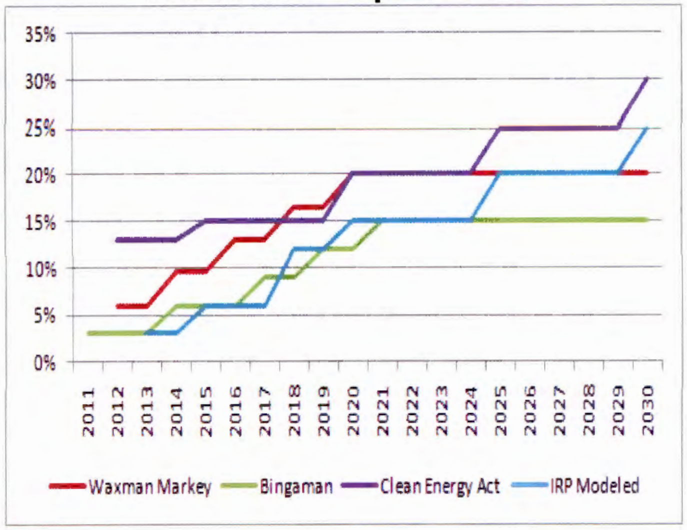


Table 5.13 Comparison of Proposed Federal RES

Issue Category	Waxman Markey	Bingaman	Clean Energy Act	IRP Modeled
Retail Supplier	4,000,000 MWh or greater			4,000,000 MWh or greater
Requirement Base	Total Retail MWh sold Excluding - Non Qualified Hydro, Nuclear, Sequestered Coal or Gas Generation	Total Retail MWh sold	Total Retail MWh sold Excluding - Non Qualified Hydro but not Pumped Storage and Incineration of municipal waste	Total Retail MWh sold Excluding - Non Qualified Hydro, Nuclear, Sequestered Coal or Gas Generation, Pumped Storage
Eligible Energy Resources	Wind, Solar, Geothermal, Biomass, Biogas, Biofuels, Qualified Hydro, Cofire	Wind, Solar, Geothermal, Biomass, Biogas, Biofuels, Qualified Hydro, Cofire, Energy Efficiency	Wind, Solar, Geothermal, Biomass, Biogas, Biofuels, Qualified Hydro, Landfill, Cofire, Energy Efficiency, Qualified Nuclear (upgrades & new), Retired Fossil Fuel, Coal w/sequestered 65% CO2	Wind, Solar, Geothermal, Biomass, Biogas, Biofuels, Qualified Hydro, Cofire, Energy Efficiency
Distributed Generation	< 2MW If from renewable will get 3-to-1 REC value for output			
REC Alternative Payment	$25/REC Inflation Adjusted	$21/REC Inflation Adjusted	$50/REC Inflation Adjusted. Can petition Secretary waive requirements	$25/REC Inflation Adjusted
Rate Impact		Can petition to limit rate impact to < 4%/yr.	Can petition to limit rate impact to < 4%/yr.	Rate impact to < 4%/yr.
Native American Land	Doubles REC Credits		Double REC Credits, and triple credits from small clean <1 Generation	
Energy Efficiency Limitations	Does Not Apply	No more than 26.67% of REC requirement can be supplied from EE	No more than 25% of REC requirement can be supplied from EE	No more than 25% of REC requirement can be supplied from EE
REC Life	No Limit identified	3 Years	No Limit (indefinite)	3 Years

One of the unique considerations in the Waxman-Markey proposal is the exclusion of Non-Qualified Hydro and Nuclear generation from the base for the RES requirement. Additionally it was assumed that the Federal RES portfolios also met the Missouri renewable requirements. This constraint did not provide any significant changes in the development of a compliant portfolio other than the solar carve out provision in the Missouri RES. For modeling purposes co-firing was the same for each Federal compliant portfolio with wind used as the resource added to meet energy requirements. To support the necessary co-firing output, over 55,000 MMBtu per day is required which exceeds the fuel supply identified by Black and Veatch's assessment of the region. To the extent the fuel supply is not available upon implementation, the amount of new wind would have to be increased to reach compliance.

Federal RES Results

Figure 5.16 shows Ameren Missouri's renewable position compared to potential Federal RES requirements. Although there were 8 different Federal renewable portfolios, Figure 5.16 represents the Federal RES compliant portfolio that includes the Low Risk DSM portfolio and Noranda continuing as a retail customer. The modeled 4% rate cap had no effect on the amount of new renewables. Table 5.14 shows the data in tabular form.

Figure 5.16 Federal RES Compliant Renewable Portfolio

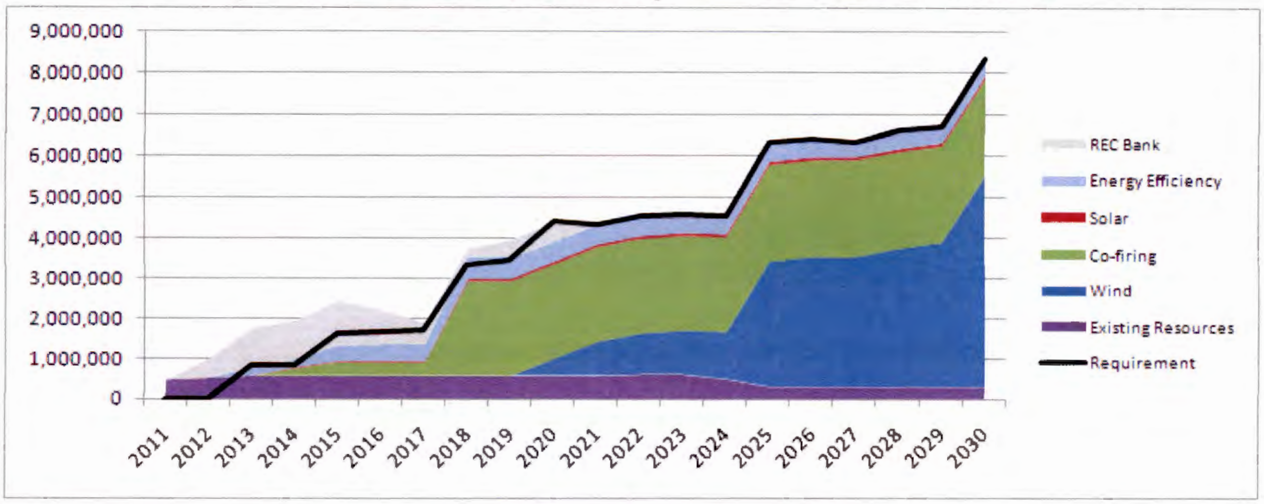


Figure 5.17 shows the difference in the amount of wind added depending on the energy efficiency portfolio and Noranda's status. Since the rate cap was not a limiting factor there is more differentiation than for the Missouri RES. Although MAP is more aggressive than RAP both are limited by the 25% maximum contribution of energy efficiency that can be counted toward the requirement. As expected, with the expiration of retail sales to Noranda the need for renewables decreased accordingly.

Figure 5.17 Difference in Wind Between Federal RES Portfolios

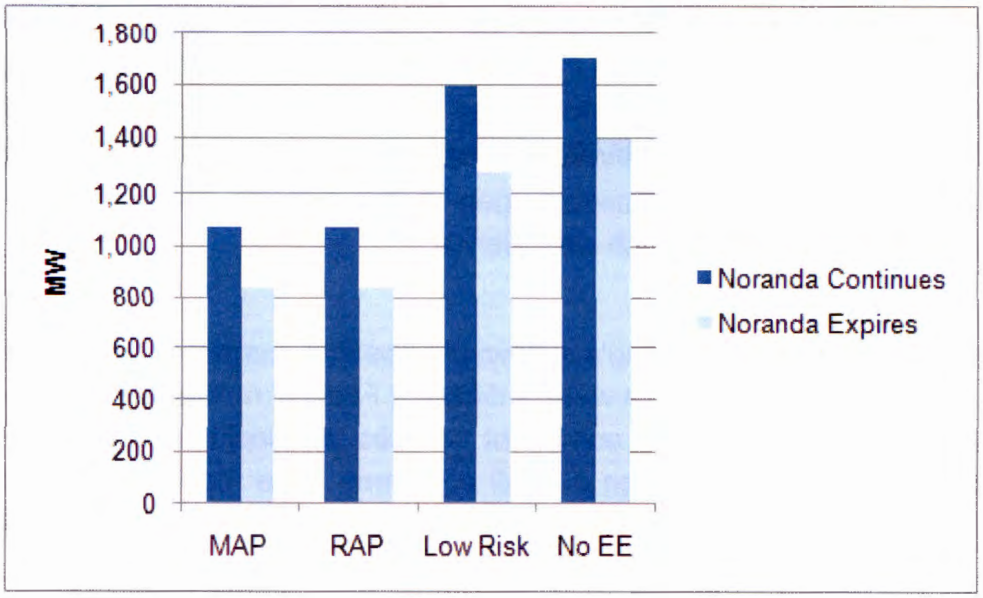


Table 5.14 Federal RES Renewable Position

Year	GWh Retail Forecast - No EE	Nuclear Output	Non-Qualified Hydro	Pumped Storage	Retail Load Base GWh	RES Req.	Energy Efficiency Credits	Existing Resources	New Landfill Gas Energy	New Cofiring Energy	New Wind Energy	New Solar Energy	Solar Renewable Need (Short)/Long	Actual Renewable Percent	RES Req.
2011	37,822	-9,545	-1,435	-803	26,039	--	--	460	0	0	0	15	475	--	--
2012	38,545	-10,401	-1,435	-794	25,915	--	--	460	48	0	0	15	999	--	--
2013	38,781	-9,570	-1,449	-795	26,968	809	202	460	96	0	0	15	964	3%	3%
2014	39,072	-9,574	-1,462	-793	27,242	817	204	460	96	184	0	39	1,130	4%	3%
2015	39,410	-10,401	-1,475	-834	26,700	1,602	401	461	96	339	0	39	864	5%	6%
2016	39,855	-9,568	-1,501	-834	27,951	1,677	419	461	96	339	0	39	542	5%	6%
2017	40,058	-9,573	-1,514	-834	28,135	1,688	422	461	96	339	0	40	213	5%	6%
2018	40,419	-10,401	-1,514	-834	27,670	3,320	548	461	96	2,362	0	80	439	13%	12%
2019	40,854	-9,570	-1,514	-834	28,935	3,472	528	461	96	2,362	0	81	495	12%	12%
2020	41,365	-9,575	-1,514	-834	29,442	4,416	492	461	96	2,362	429	81	0	13%	15%
2021	41,678	-10,401	-1,514	-834	28,929	4,339	484	461	96	2,362	855	81	0	15%	15%
2022	42,122	-9,568	-1,514	-834	30,205	4,531	470	461	128	2,362	1,028	81	0	15%	15%
2023	42,581	-9,573	-1,514	-834	30,659	4,599	461	461	128	2,362	1,104	82	0	15%	15%
2024	43,176	-10,401	-1,514	-834	30,427	4,564	460	347	128	2,362	1,184	83	0	15%	15%
2025	43,525	-9,570	-1,514	-834	31,607	6,321	450	125	161	2,362	3,141	83	0	20%	20%
2026	44,016	-9,575	-1,514	-834	32,093	6,419	435	125	161	2,362	3,253	84	0	20%	20%
2027	44,523	-10,401	-1,514	-834	31,773	6,355	422	125	161	2,362	3,253	84	51	20%	20%
2028	45,173	-9,568	-1,514	-834	33,256	6,651	408	125	161	2,362	3,459	85	0	20%	20%
2029	45,568	-9,574	-1,514	-834	33,645	6,729	393	125	161	2,362	3,602	86	0	20%	20%
2030	46,101	-10,401	-1,514	-834	33,352	8,338	374	125	161	2,362	5,229	88	0	25%	25%

5.6 Compliance References

Chapter 5 - Appendix A

Fatal Flaw Analysis – Energy Storage Technologies

Description	Fatal Flaw
Pumped Hydro Energy Storage	✓
Compressed Air Energy Storage (CAES)	✓
Hydrogen Storage/Fuel Cell Generation	✗
Thermal or Pumped Heat Energy Storage	✗
Zinc – Bromine Flow Battery (ZnBr)	✗
Sodium Sulfur Battery (NaS)	✗
Lithium – Ion Battery (Li-Ion)	✗
Advanced Lead Acid Battery	✗
Metal – Air Battery	✗
Vanadium Redox Flow Battery	✗
Lead – Carbon Battery (PbC)	✗
Nickel – Cadmium Battery (NiCad)	✗
Flywheels	✗

A high-level fatal flaw analysis was conducted as part of the first stage of the supply-side selection analysis. 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 for one or more of the following reasons:

- The storage technology is cost prohibitive to install and equally cost prohibitive and/or burdensome to maintain.
- The storage technology, while perhaps advancing, is still in the development or demonstration phase and hence is not field-proven. (In fact, very few storage technologies above have utility scale applications that are operational in the United States, and some are still not commercially available even in community or household scale applications.)
- The storage application is overly limited by a short cycle life, especially if deeply discharged.
- The storage application is limited for various reasons in its scalability to either utility-grade or community-grade installations. The application may, in fact, not be intended for anything other than consumer end-use behind-the-meter.
- The storage application is hampered by low cycle efficiencies or energy densities.
- The storage application is hampered by environmental risk (e.g. batteries whose chemical elements are considered hazardous materials or have combustible tendencies under different operating conditions).

- Responses by potential vendors to an energy storage survey sent by Ameren for purposes of getting additional information and determining storage technology applicability and cost were very sparse – this was perceived as indicative of the overall state of the energy storage industry.

Additionally, there are a number of reasons in general why Ameren Missouri may not be able to develop as strong a business case for energy storage as other utilities:

- Ameren Missouri is not currently operating in a capacity-constrained environment from either a generation or energy delivery standpoint.
- Ameren Missouri is not currently operating in a real estate-constrained environment. When line or substation capacity additions are necessary, Ameren Missouri is not typically hampered by physical constraints associated with the expansion and upgrade of facilities.
- Ameren Missouri is not currently subject to the type of power market volatility that warrants the strategic use of energy storage from an arbitrage standpoint.
- Ameren Missouri is not currently hampered by the types of service reliability problems that would make energy storage a strategic option. In fact, as a direct a result of a number of reliability-based initiatives undertaken over the past several years, Ameren Missouri customers are experiencing measurably improved levels of electric service reliability.
- Ameren Missouri does not currently have a substantive amount of non-dispatchable intermittent resources in its generation portfolio to warrant a serious consideration of widespread energy storage.

Chapter 5 - Appendix B

Characterization Data – Renewable and Storage Resources[1]

Resource Option	Renewable Resource	Operations Mode	Technology Description	Plant Output, MW	Heat Rate HHV, Btu/kWh	Assumed Fuel Type / Source	Fuel Flexibility	Technology Maturity	Permitting, months	NTP to COD, months	Assumed Annual Capacity Factor, percentage	Forced Outage Rate, percentage
Compressed Air Energy Storage	n/a	Peaking	CAES	600	4,400	Nat Gas/Electric	Limited	Developing	18 to 24	48	30%	5%
Pumped Hydro Storage	n/a	Peaking	Pumped Storage	600	n/a	Hydro	n/a	Mature	36 to 48	72	25%	n/a
Wind	Wind	Intermittent	Wind	100	n/a	Wind	n/a	Mature	18 to 36	12	36%	n/a
Solar	Solar	Intermittent	PV	1	n/a	Solar	n/a	Mature	9 to 15	12	21%	n/a
Co-firing (St. Louis Region) 0 Note 1	Biomass	Baseload	Existing Host	28.8	10,125	Wood	Yes	Mature	12 to 18	12	85%	9%
Wood-fired Standalone (Ellington Region)	Biomass	Baseload	Sub Critical	13.5	14,500	Wood	Yes	Mature	18 to 24	32	80%	9%
Poultry-litter Standalone (Monett Region)	Biomass	Baseload	Sub Critical	29.6	14,500	Wood/Litter	Yes	Mature	18 to 24	32	80%	9%
Ozark Beach	Hydro	Baseload	Hydro	5	n/a	n/a	n/a	Mature	21 to 27	24	40%	5%
Clearwater	Hydro	Baseload	Hydro	5.3	n/a	n/a	n/a	Mature	21 to 27	24	40%	5%
Pomme De Terre	Hydro	Baseload	Hydro	4.6	n/a	n/a	n/a	Mature	21 to 27	24	60%	5%
Mississippi L&D 21	Hydro	Baseload	Hydro	10	n/a	n/a	n/a	Mature	21 to 27	24	40%	5%
Bridgeton	LFG	Baseload	RICE	8	13,560	LFG	No	Mature	12 to 18	15	92%	5%
Fred Weber	LFG	Baseload	CT	13	12,250	LFG	No	Mature	12 to 18	15	90%	5%
Lemons East	LFG	Baseload	RICE	2	13,750	LFG	No	Mature	12 to 18	15	90%	5%
Missouri Pass	LFG	Baseload	RICE	2.5	12,500	LFG	No	Mature	12 to 18	15	90%	5%
Veolia Maple Hill	LFG	Baseload	RICE	4	13,750	LFG	No	Mature	12 to 18	15	92%	5%
Mercer County 1	AD	Baseload	RICE	3.9	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Sullivan County 1	AD	Baseload	RICE	3.2	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Gentry County 1	AD	Baseload	RICE	2.1	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Putnam County 1	AD	Baseload	RICE	2.1	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Sullivan County 2	AD	Baseload	RICE	2.1	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Gentry County 2	AD	Baseload	RICE	1.9	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Sullivan County 3	AD	Baseload	RICE	1.8	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Mercer County 2	AD	Baseload	RICE	1.1	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Putnam County 2	AD	Baseload	RICE	3.2	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Sullivan County 4	AD	Baseload	RICE	3.1	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Vernon County	AD	Baseload	RICE	1.4	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Johnson County	AD	Baseload	RICE	2.5	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Lincoln County	AD	Baseload	RICE	1.4	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%
Lewis County	AD	Baseload	RICE	1.2	12,000	Digester Gas	No	Mature	12 to 18	12	90%	5%

[1] 4 CSR 240-22.040(1)(A); 4 CSR 240-22.040(1)(B); 4 CSR 240-22.040(1)(C); 4 CSR 240-22.040(1)(D); 4 CSR 240-22.040(1)(I); 4 CSR 240-22.040(1)(J)

Characterization Data – Renewable and Storage Resources[2]

Resource Option	Renewable Resource	Tax Life, years	Economic Life, years	Owner's Cost, percent	AFUDC Cost, percent	Total Owner's Cost, percent	EPC Capital Cost, $1,000	EPC Capital Cost, $/kW	Total Project Cost - Includes Owners Cost, $1,000	Total Project Cost - Includes Owners Cost, $/kW
Compressed Air Energy Storage	n/a	20	30	30%	16%	46%	$690,000	$1,150	$1,006,800	$1,680
Pumped Hydro Storage	n/a	20	40	43%	4%	47%	$1,157,287	$1,930	$1,700,000	$2,830
Wind	Wind	5	20	10%	9%	19%	$181,800	$1,818	$200,000	$2,000
Solar	Solar	5	20	1%	4%	5%	$5,941	$5,941	$6,000	$6,000
Co-firing (St. Louis Region) 0 Note 1	Biomass	7	20	26%	4%	30%	$21,600	$750	$27,400	$950
Wood-fired Standalone (Ellington Region)	Biomass	7	20	19%	11%	30%	$96,500	$7,150	$114,900	$8,510
Poultry-litter Standalone (Monett Region)	Biomass	7	20	19%	11%	30%	$153,900	$5,200	$183,200	$6,190
Ozark Beach	Hydro	20	30	22%	8%	30%	$12,500	$2,500	$15,300	$3,050
Clearwater	Hydro	20	30	22%	8%	30%	$21,200	$4,000	$25,900	$4,880
Pomme De Terre	Hydro	20	30	22%	8%	30%	$16,100	$3,500	$19,600	$4,270
Mississippi L&D 21	Hydro	20	30	22%	8%	30%	$50,000	$5,000	$61,000	$6,100
Bridgeton	LFG	7	15	25%	5%	30%	$24,300	$3,040	$30,400	$3,800
Fred Weber	LFG	7	15	25%	5%	30%	$39,000	$3,000	$48,800	$3,750
Lemons East	LFG	7	15	25%	5%	30%	$6,500	$3,240	$8,100	$4,050
Missouri Pass	LFG	7	15	25%	5%	30%	$8,900	$3,570	$11,200	$4,460
Veolia Maple Hill	LFG	7	15	25%	5%	30%	$13,000	$3,240	$16,200	$4,050
Mercer County 1	AD	7	15	26%	4%	30%	$42,900	$11,000	$54,100	$13,860
Sullivan County 1	AD	7	15	26%	4%	30%	$36,000	$11,250	$45,400	$14,160
Gentry County 1	AD	7	15	26%	4%	30%	$25,000	$11,900	$31,500	$14,990
Putnam County 1	AD	7	15	26%	4%	30%	$25,100	$11,950	$31,600	$15,060
Sullivan County 2	AD	7	15	26%	4%	30%	$25,100	$11,950	$31,600	$15,060
Gentry County 2	AD	7	15	26%	4%	30%	$23,100	$12,150	$29,100	$15,310
Sullivan County 3	AD	7	15	26%	4%	30%	$22,000	$12,200	$27,700	$15,370
Mercer County 2	AD	7	15	26%	4%	30%	$14,900	$13,500	$18,700	$17,010
Putnam County 2	AD	7	15	26%	4%	30%	$36,000	$11,250	$45,400	$14,180
Sullivan County 4	AD	7	15	26%	4%	30%	$35,000	$11,300	$44,100	$14,240
Vernon County	AD	7	15	26%	4%	30%	$18,100	$12,900	$22,800	$16,250
Johnson County	AD	7	15	26%	4%	30%	$29,000	$11,600	$36,600	$14,620
Lincoln County	AD	7	15	26%	4%	30%	$17,900	$12,800	$22,600	$16,130
Lewis County	AD	7	15	26%	4%	30%	$16,000	$13,350	$20,200	$16,820

[2] 4 CSR 240-22.040(1)(A); 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(8)(B)

Characterization Data – Renewable and Storage Resources[3]

Resource Option	Renewable Resource	First Year Fixed O&M Cost, $1,000/yr	First Year Fixed O&M Cost, $/kW-yr	First Year Variable O&M Cost, $1,000/yr	First Year Variable O&M Cost, $/MWh	First Year Total O&M Cost, $/MWh	First Year Fuel Cost, $/MBtu	NOx, lbm/MBtu	SO2, lbm/MBtu	CO2, lbm/MBtu
Compressed Air Energy Storage	n/a	2,820	4.7	5319	3.4	5.2	6.09	0.1	0.0006	117
Pumped Hydro Storage	n/a	1910	3.18	4244	3.23	6.41	n/a	0	0	0
Wind	Wind	5,000	50	0	0	50	n/a	0	0	0
Solar	Solar	10	10	0	0	10	n/a	0	0	0
Co-firing (St. Louis Region) 0 Note 1	Biomass	1,300	45	0	0	45	2.66	0	<0.1	carbon neutral
Wood-fired Standalone (Ellington Region)	Biomass	4000	295	1400	15	310	2.98	0	<0.1	carbon neutral
Poultry-litter Standalone (Monett Region)	Biomass	4400	150	2200	11	161	2.69	0	<0.1	carbon neutral
Ozark Beach	Hydro	0	0	90	5	5	n/a	0	0	0
Clearwater	Hydro	0	0	95	5	5	n/a	0	0	0
Pomme De Terre	Hydro	0	0	120	5	5	n/a	0	0	0
Mississippi L&D 21	Hydro	0	0	175	5	5	n/a	0	0	0
Bridgeton	LFG	300	40	700	10.9	50.9	2	0	Note 1	carbon neutral
Fred Weber	LFG	300	20	820	10.4	30.4	2	0	Note 1	carbon neutral
Lemons East	LFG	300	170	180	11.2	181.2	2	0	Note 1	carbon neutral
Missouri Pass	LFG	100	40	260	12.9	52.9	2	0	Note 1	carbon neutral
Veolia Maple Hill	LFG	700	170	360	11.2	181.2	2	0	Note 1	carbon neutral
Mercer County 1	AD	3,600	920	0	0	920	n/a	0	Note 1	carbon neutral
Sullivan County 1	AD	3000	930	0	0	930	n/a	0	Note 1	carbon neutral
Gentry County 1	AD	2000	975	0	0	975	n/a	0	Note 1	carbon neutral
Putnam County 1	AD	2100	980	0	0	980	n/a	0	Note 1	carbon neutral
Sullivan County 2	AD	2100	980	0	0	980	n/a	0	Note 1	carbon neutral
Gentry County 2	AD	1900	990	0	0	990	n/a	0	Note 1	carbon neutral
Sullivan County 3	AD	1800	992	0	0	992	n/a	0	Note 1	carbon neutral
Mercer County 2	AD	1200	1075	0	0	1075	n/a	0	Note 1	carbon neutral
Putnam County 2	AD	3000	930	0	0	930	n/a	0	Note 1	carbon neutral
Sullivan County 4	AD	2900	940	0	0	940	n/a	0	Note 1	carbon neutral
Vernon County	AD	1500	1040	0	0	1040	n/a	0	Note 1	carbon neutral
Johnson County	AD	2400	950	0	0	950	n/a	0	Note 1	carbon neutral
Lincoln County	AD	1400	1030	0	0	1030	n/a	0	Note 1	carbon neutral
Lewis County	AD	1300	1065	0	0	1065	n/a	0	Note 1	carbon neutral

Note 1 - SO2 emissions are highly variable. Sulfur in bio-gas can range from 100 ppmvd to 12,000 ppmvd.

[3] 4 CSR 240-22.040(1)(F); 4 CSR 240-22.040(1)(G); 4 CSR 240-22.040(1)(K)1.; 4 CSR 240-22.040(8)(C)