Chapter 4 - Appendix B

Preliminary Screening Analysis[1]

Option	Description	Candidate Option
Coal	Greenfield - IGCC	✓
Coal	Greenfield - IGCC with Pre-Combustion CCC	✓
Coal	Greenfield - Oxyfuel Coal with CCC	✗
Coal	Greenfield - Subcritical CFB	✗
Coal	Greenfield - Subcritical CFB with Amine-Based Post-Combustion CCC	✗
Coal	Greenfield - Supercritical CFB	✗
Coal	Greenfield - USCPC	✓
Coal	Greenfield - USCPC with Amine-Based Post-Combustion CCC	✓
Coal	Meramec - Oxyfuel Coal with CCC	✗
Coal	Meramec - Subcritical CFB	✗
Coal	Meramec - Ultra-Supercritical (USC) PC	✗
Coal	Meramec Repowering - CFB Boiler Replacement	✗
Coal	Meramec Repowering - Oxyfuel Coal Boiler Replacement	✗
Coal	Meramec Repowering - Unit 3 Boiler Replacement and STG	✗
Coal	Meramec Repowering - Unit 4 Boiler Replacement and STG	✗
Coal	Rush Island - Integrated Gasification Combined Cycle (IGCC)	✗
Coal	Rush Island - Oxyfuel Coal with CCC	✗
Coal	Rush Island - Subcritical CFB	✗
Coal	Rush Island - USCPC	✗
Coal	Efficiency Improvements to Existing Plants – Condenser Back-pressure Reductions	✗
Coal	Efficiency Improvements to Existing Plants – Duct Draft	✗
Gas	Goose Creek - Inlet Chilling SCCT Power Augmentation	✗
Gas	Goose Creek - Wetted Media SCCT Power Augmentation	✗
Gas	Greenfield - 2-on-1 501F CCCT	✓
Gas	Greenfield – 2-on-1 Wartsila 20V34SG Combined Cycle	✗
Gas	Greenfield - CCCT Amine-Based Post-Combustion CCC	✗
Gas	Greenfield – GE 7EA Cheng Cycle	✗
Gas	Greenfield - Molten Carbonate Fuel Cell	✗
Gas	Greenfield - Natural Gas Fueled Rankine Cycle	✗
Gas	Greenfield - Twelve Wartsila 20V34SG Simple Cycle	✗
Gas	Greenfield - Two 501F SCCTs (10% CF)	✓

[1] 4 CSR 240-22.040(1)

Option	Description	Candidate Option
Gas	Greenfield - Two 501F SCCTs (5% CF)	✓
Gas	Meramec - 2-on-1 501F CCCT	✓
Gas	Meramec Repowering - Unit 3 & Unit 4 STGs in a Shared CCCT	✗
Gas	Meramec Repowering - Unit 3 & Unit 4 STGs in Separate CCCT	✗
Gas	Meramec Repowering - Unit 3 Boiler NG Conversion	✗
Gas	Meramec Repowering - Unit 4 Boiler NG Conversion	✗
Gas	Meramec Repowering - Unit 4 STG in a 3-on-1 CCCT	✓
Gas	Mexico - One GE LM6000 Sprint SCCT (10% CF)	✓
Gas	Mexico - One GE LM6000 Sprint SCCT (5% CF)	✓
Gas	Raccoon Creek - One GE 7EA SCCT (10% CF)	✓
Gas	Raccoon Creek - One GE 7EA SCCT (5% CF)	✓
Gas	Venice - 2-on-1 501F CCCT Conversion	✓

4.1 Technology Characterization

Following the high-level fatal flaw analysis and elimination of several options, the list of options to be evaluated as part of the second stage of the screening analysis was reduced. Cost, performance, and operating characteristics were developed for each of the remaining options in support of the Preliminary Screening with input from Ameren Missouri and Black & Veatch's internal resources.

All performance and cost estimates were based on technologies fueled by the following design fuels[2]:

- Coal - All coal-fueled options are characterized such that they can operate on either 100 percent Powder River Basin (PRB) coal or 100 percent Illinois Basin No. 6 coal (or on any combination of the two). Thermal performance and emissions estimates for the coal-fueled options assume 100 percent of the feedstock is PRB coal. The air quality control systems (AQCS) for coal-fueled options were selected to achieve target emissions limits for either coal assuming representative fuel properties for Illinois Basin No. 6 coal.
- Natural Gas - All gas-fueled options would be designed to operate on pipeline quality natural gas, assumed to be 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet, unless specified otherwise.

4.1.1 Capacity Ranges

Each of the generation technologies identified in the evaluated options list has sizing limitations. The selection of practical size ranges for each of the technologies is based

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

on Ameren Missouri's ability to plan for and reasonably implement the technology. Table 4.B.1 provides a summary of approximate size limitations for new generation units[3].

Table 4.B.1 Capacity Ranges

Technology Description	Single Unit Size	
	Lower Range (MW)	Upper Range (MW)
Ultra-Supercritical PC	500	1,000
Oxyfuel Coal	30	100
Subcritical Circulating Fluidized Bed	100	600
Integrated Gasification Combined Cycle	125	630
Supercritical Circulating Fluidized Bed	100	460
Simple Cycle Combustion Turbine	20	270
Combined Cycle Combustion Turbine	25	1,200
Molten Carbonate Fuel Cells	< 1	3
Simple Cycle Reciprocating Engine	< 1	17
Combined Cycle Reciprocating Engine	18	37

Full load thermal performance and emissions were developed for all evaluated options. Thermal performance was estimated for a 95° F day and a 20° F day. Site conditions were selected to reflect Ameren Missouri's service area. The following elevation and ambient conditions were assumed for all performance estimates:

- Elevation--500 feet above mean sea level.
- 20° F day ambient conditions:
  - Dry bulb temperature--20° F.
  - Relative humidity--60 percent.
- 95° F day ambient conditions:
  - Dry bulb temperature--95° F.
  - Relative humidity--60 percent.

Capacity and performance data for each evaluated option are presented in Table 4.B.12 and Table 4.B.13 under the Supporting Tables section.

4.1.2 Commercial Availability

The commercial status of each of the evaluated technologies was qualitatively assessed. Technology maturity was assessed as either "mature" or "developing."

[3] 4 CSR 240-22.040(1)(B)

Technologies defined as mature were those that are proven and well established within the electric power generation industry. Developing technologies consist of all other technologies that may have limited experience, have been utilized in demonstration projects, or consist of laboratory-tested conceptual designs.

4.1.3 Capital Cost Estimates

Screening level, overnight EPC capital cost estimates were developed for all evaluated options and expressed in 2009 dollars. The values presented are reasonable for today's market conditions, but, as demonstrated in recent years, the market is dynamic and unpredictable. Power plant costs are subject to continued volatility and the estimates in this report should be considered primarily for comparative purposes. The EPC costs presented in this report were developed in a consistent manner and are reasonable relative to one another.

The EPC estimates include costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis and are representative of "inside the fence" project scope. The estimates were developed using Black & Veatch proprietary estimating templates and experience. The overall capital cost estimates consist of three main components: EPC Capital Cost, Owner's Cost (excluding AFUDC [Allowance for Funds Used during Construction]), and Owner's AFUDC Cost. Capital costs for all evaluated options are presented in Table 4.B.14 and Table 4.B.15.

An allowance has been made for Owner's costs (excluding AFUDC). Items included in the Owner's costs include "outside the fence" physical assets, project development, and project financing costs. These costs can vary significantly, depending upon technology and unique project requirements. Black & Veatch has developed Owner's costs as a percentage of the EPC capital cost as shown in the tables referenced above. Owner's costs are assumed to include project development costs, interconnection costs, spare parts and plant equipment, project management costs, plant startup/construction support costs, taxes/advisory fees/legal costs, contingency, financing and miscellaneous costs. Table 4.B.2 shows a more detailed explanation of potential owner's costs.

For the purposes of characterizing all of the evaluated options, the AFUDC was calculated by applying the Present Worth Discount Rate (PWDR) over half of the construction duration, with the construction duration being defined as the time period from Notice to Proceed (NTP) to Commercial Operation Date (COD).

Table 4.B.2 Potential Items for Owner's Costs[4]

Project Development: Site selection study Land purchase/options/rezoning Transmission/gas pipeline rights of way Road modifications/upgrades Demolition (if applicable) Environmental permitting/offsets Public relations/community development Legal assistance **Utility Interconnections:** Natural gas service (if applicable) Gas system upgrades (if applicable) Electrical transmission Supply water Wastewater/sewer (if applicable) **Spare Parts and Plant Equipment:** Air quality control systems materials, supplies, and parts Acid gas treating materials, supplies and parts Combustion turbine and steam turbine materials, supplies, and parts HRSG materials, supplies, and parts Gasifier materials, supplies, and parts Balance-of-plant equipment materials, supplies and parts Rolling stock Plant furnishings and supplies Operating spares **Owner's Project Management:** Preparation of bid documents and selection of contractor(s) and suppliers Provision of project management Performance of engineering due diligence Provision of personnel for site construction management	**Plant Startup/Construction Support:** Owner's site mobilization O&M staff training Supply of trained operators to support equipment testing and commissioning Initial test fluids and lubricants Initial inventory of chemicals/reagents Consumables Cost of fuel not recovered in power sales Auxiliary power purchase Construction all-risk insurance Acceptance testing **Taxes/Advisory Fees/Legal:** Taxes Market and environmental consultants Owner's legal expenses: • Power Purchase Agreement (PPA) • Interconnect agreements • Contracts--procurement & construction • Property transfer **Owner's Contingency:** Owner's uncertainty and costs pending final negotiation: • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreement (e.g., interconnection contract costs) **Financing:** Development of financing sufficient to meet project obligations or obtaining alternate sources of funding Financial advisor, lender's legal, market analyst, and engineer Interest during construction Loan administration and commitment fees Debt service reserve fund **Miscellaneous:** All costs for above-mentioned Contractor-excluded items, if applicable

[4] 4 CSR 240-22.040(3); 4 CSR 240-22.040(6)

4.1.4 Non-Fuel O&M Costs

Nonfuel O&M cost estimates were developed for each of the evaluated options. All O&M cost estimates are presented in Table 4.B.14 and Table 4.B.15. First year O&M costs (in 2009 $'s) were estimated, and for the future years 3% escalation rate was used.

The modes of dispatch used to establish maintenance intervals for many of the options are as follows:

<u>Baseload Dispatch Profiles</u> – Excluding the IGCC options, all options evaluated at a baseload dispatch mode were assumed to operate at full load at a capacity factor of 85 percent. An IGCC facility is not anticipated to be capable of operating at such a high capacity factor because of the degree of process integration. All IGCC options were assumed to operate at full load at a capacity factor of 80 percent. Options incorporating Carbon Capture and Compression (CCC) were assumed to operate at the same dispatch profile as their non-carbon capture counterparts.

<u>Intermediate Load Dispatch Profiles</u> – Two operating profiles were used for the intermediate load technologies.

- **Profile 1 – Cycling Operation – Off Nights/Off Weekends**: 6 months per year operation at 5 days a week, 8 hours per day in 2x1 combined cycle mode, off-line 16 hours per day and on weekends. Shut down and laid up for 6 winter months per year. Total full load operation of 1,043 hours per year and a capacity factor of about 12 percent.
- **Profile 2 – Cycling Operation – Low Load Nights/Off Weekends**: 6 months per year at 5 days a week, 10 hours per day in 2x1 combined cycle mode, 14 hours per day in 1x1 combined cycle mode at minimum load on the steam turbine, shut down on weekends. Shut down and laid up for 6 winter months per year. This equates to a capacity factor of about 21 percent for the options evaluated in this study.

<u>Peaking Load Dispatch Profiles</u> – All new unit combustion turbine options were evaluated at a peaking dispatch mode, with capacity factors of 5 and 10 percent. It was assumed that 90 starts were associated with a 5 percent capacity factor and 150 starts with a 10 percent capacity factor.

Power augmentation and reciprocating engines operating in simple cycle were evaluated at a 5 percent capacity factor.

4.1.5 Scheduled and Forced Outages

Scheduled maintenance intervals were obtained from original equipment manufacturers (OEMs) or estimated on the basis of Black & Veatch experience for each of the technologies. Where information was not available, maintenance intervals were estimated using data gathered from comparable technologies. These scheduled maintenance patterns were assumed to be the same for technologies employing CCC equipment. The maintenance patterns are presented in Table 4.B.3.

Table 4.B.3 Scheduled Maintenance Outage Patterns[5]

Technology Description	Weeks/Year
Ultra-Supercritical PC (Note 1)	4-4-4-6
Subcritical Circulating Fluidized Bed (Note 2)	3-3-3-3-3-6
Integrated Gasification Combined Cycle (Note 3)	3-3-3-3-3-4
Meramec Repowering - Unit 3 Boiler NG Conversion (Note 4)	3-3-3-6
Meramec Repowering - Unit 4 Boiler NG Conversion (Note 4)	3-3-3-6
Meramec Repowering - Unit 3 Boiler Replacement and STG Rebuild (Note 1)	4-4-4-6
Meramec Repowering - Unit 4 Boiler Replacement and STG Rebuild (Note 1)	4-4-4-6
Meramec Repowering - Unit 4 STG in a CCCT Conversion (Note 5)	1-1-2-1-1-6
Supercritical Circulating Fluidized Bed (Note 2)	3-3-3-3-3-6
Combined Cycle Combustion Turbine (Note 5)	1-1-2-1-1-6
Molten Carbonate Fuel Cells (Note 6)	1
Combined Cycle Reciprocating Engine (Note 7)	2-3-2-3-2-4
Cheng Cycle – 7EA (Note 8)	1-1-2-1-1-4
Siemens 501F (Note 9)	1-2-1-4
GE LM6000 Sprint (Note 10)	1-10
GE 7EA (Note 8)	1-1-2-1-1-4
Goose Creek - Inlet Chilling Augmentation (Note 8)	1-1-2-1-1-4
Goose Creek - Wetted Media Augmentation (Note 8)	1-1-2-1-1-4
Wartsila 20V34SG Reciprocating Engine (Simple Cycle) (Note 7)	2-3-2-3-2-4

Notes:
(1) 4 week boiler outage every 18 months and a 6 week STG major outage every 6 years.
(2) 3 week boiler outage every 12 months and a 6 week STG major outage every 6 years.
(3) Alternating 1 week and 3 week combined cycle outages yearly, alternating 3 week and 2 week gasification outages yearly and a 4 week combined cycle outage every 6 years. This schedule is representative of planned maintenance beginning in year 4. Longer gasification outage durations are expected for years 1 through 3.
(4) 3 week boiler outage every 18 months and a 6 week STG major outage every 6 years.
(5) Siemens recommends the following: 1 week combustion inspection every 8,333 eq. hours, 2 week hot gas path inspection every 25,000 eq. hours, and a 4 week major inspection every 50,000 eq. hours for the combustion turbine. A 6 week major outage is recommended at 50,000 eq. hours for the STG.
(6) Short outages required every 2,000 to 3,000 hours of operation.
(7) 2 week per 8,000 hours, 3 weeks per 16,000 hours, and 4 weeks per 48,000 hours.

[5] 4 CSR 240-22.040(1)(G)

(8) GE recommends the following: 1 week combustion inspection every 450 starts, 2 week hot gas path inspection every 1,200 starts, and a 4 week major inspection every 2,400 starts.
(9) Siemens recommends the following: 1 week combustion inspection every 450 starts, 2 week hot gas path inspection every 900 starts, and a 4 week major inspection every 1,800 starts.
(10) GE recommends the following: 1 week hot section rotable exchange every 25,000 hours and a 10 week (nominal) engine overhaul every 50,000 hours.

Where available, generic equivalent forced outage rate (EFOR) and equivalent demand forced outage rate (EFORd) data were gathered for each of the technologies. The EFOR and EFORd data are presented in Table 4.B.4. The information was taken from the NERC GADS database and published literature to the extent that data were available. When information was not available, values were estimated using data gathered from comparable technologies. EFOR and EFORd were not estimated for technologies employing CCC equipment. For this effort and at this stage of planning, it is assumed that the availability of CCC equipment is independent of the generating facility availability and does not affect EFOR and EFORd. The information is generic, but representative for screening-level supply-side resource analyses.

Table 4.B.4 Forced Outage Rates[6]

Technology Description	EFOR, %	EFORd, %
Ultra-Supercritical PC	8%	8%
Subcritical Circulating Fluidized Bed	11%	10%
Integrated Gasification Combined Cycle	13%	13%
Meramec Repowering - Unit 3 Boiler NG Conversion	8%	7%
Meramec Repowering - Unit 4 Boiler NG Conversion (Note 4)	8%	7%
Meramec Repowering - Unit 3 Boiler Replacement and STG Rebuild	7%	7%
Meramec Repowering - Unit 4 Boiler Replacement and STG Rebuild	7%	7%
Meramec Repowering - Unit 4 STG in a CCCT Conversion	5%	4%
Supercritical Circulating Fluidized Bed	11%	10%
Combined Cycle Combustion Turbine	3%	2%
Molten Carbonate Fuel Cells	2%	2%
Combined Cycle Reciprocating Engine	3%	2%
Cheng Cycle – 7EA	24%	6%
Siemens 501F	17%	5%
GE LM6000 Sprint	11%	6%
GE 7EA	20%	4%
Goose Creek - Inlet Chilling Augmentation	20%	4%
Goose Creek - Wetted Media Augmentation	20%	4%
Wartsila 20V34SG Reciprocating Engine (Simple Cycle)	23%	4%

[6] 4 CSR 240-22.040(1)(I)

4.1.6 Waste Generation

Wastewater and waste solids must be processed and properly disposed. Technologies fueled by natural gas produce negligible solid waste, but can produce wastewater streams. Coal-fueled technologies produce both wastewater and waste solids. Table 4.B.5 presents a summary of the production of wastewater and solid wastes for the evaluated options.

Table 4.B.5 Waste Generation[7]

Technology Description	Wastewater, gpm	Solid Waste, tons/year
900 MW - Ultra-Supercritical PC	1200	274000
620 MW - Oxyfuel Coal	3300	274000
679 MW - Ultra-Supercritical PC with 90% Post CCC	3300	274000
600 MW - Subcritical Circulating Fluidized Bed	1000	278000
453 MW - Subcritical CFB with 90% Post CCC	2500	278000
562 MW - Integrated Gasification Combined Cycle	900	104000
493 MW – IGCC with 90% Pre CCC 2,400 108,000	2,400	108,000
237 MW - Meramec Repower - U3 Boiler NG Conversion	70	Negligible
332 MW - Meramec Repower - U4 Boiler NG Conversion	100	Negligible
276 MW - Meramec Repower - U3 Boiler Replace and STG Rebuild	70	64,000
369 MW - Meramec Repower - U4 Boiler Replace and STG Rebuild	100	86,000
834 MW - Meramec Repower - U4 STG in a CCCT Conversion	100	Negligible
600 MW - Supercritical Circulating Fluidized Bed	1,000	266,000
600 MW - Combined Cycle Combustion Turbine	750	Negligible
490 MW - CCCT with 90% Post CCC	2,300	Negligible
100 MW - Molten Carbonate Fuel Cells	Negligible	Negligible
17.8 MW - Combined Cycle Reciprocating Engine	10	Negligible
96 MW - Cheng Cycle – 7EA	Negligible	Negligible
346 MW - Siemens 501F	Negligible	Negligible
39.3 MW - Mexico - GE LM6000 Sprint	Negligible	Negligible
73.2 MW - Raccoon Creek - GE 7EA	Negligible	Negligible
54 MW - Goose Creek - Inlet Chilling Augmentation	Negligible	Negligible
18 MW - Goose Creek - Wetted Media Augmentation	Negligible	Negligible
99 MW - Wartsila 20V34SG Reciprocating Engine (Simple Cycle)	Negligible	Negligible

4.1.7 Potentially Useable Byproducts

A variety of solid materials may be generated from the combustion and gasification of coal, including fly ash, bottom ash, byproducts from FGD operation, and byproducts from coal gasification.

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

- Fly Ash – The most widely known uses for fly ash are in the cement and concrete industries. Fly ash has been used extensively for many civil engineering purposes, including structural fill, flowable fill, and road base materials. The use of fly ash is prevalent in road projects where large quantities of suitable soils may not be available. Fly ash has been blended with hydrated lime and aggregated materials to form road base materials that are stronger and more durable than conventional crushed stone or gravel base. Other applications include mineral fillers, mining applications, and agricultural uses.

- Bottom Ash – Bottom ash is widely utilized in road bases and structural fill projects. Other applications include use as a sand substitute in cement concrete mixtures, surface material on composition roof shingles, and as an antiskid material applied to roadways in the northeast part of the country.

- FGD Byproducts – The primary factor affecting the type of byproduct from lime or limestone-based wet scrubbers is the degree to which oxidation has taken place within the FGD system. If oxidation is promoted, the byproduct will be primarily in the form of calcium sulfate or FGD gypsum. If oxidation is not promoted, much of the product will remain in the calcium sulfite form. In general, FGD gypsum is the more desirable product because it is relatively easy to dewater and can be sold in a variety of re-use markets, such as wallboard production. The minimum purity requirement in the utility industry for marketing FGD gypsum is typically 95 percent or greater.

  FGD gypsum is also commonly used in the cement industry. FGD gypsum is used to replace natural gypsum as one of the final steps in the cement manufacturing process. As with wallboard, the gypsum must be free from contamination and consistent in composition. FGD gypsum has also been used successfully as an engineered material in structural fills and road bases. Gypsum is commonly used as an agricultural additive for soils deficient in calcium and sulfur. The use of FGD gypsum as a substitute for natural gypsum in agricultural applications is somewhat more flexible than in wallboard and cement manufacture because less stringent specifications on sulfite, ash, and chloride content can be tolerated.

- Coal Gasification Byproducts – The IGCC technology evaluated in this study employs a Claus sulfur recovery plant from which liquid elemental sulfur is recovered. This sulfur is commonly used in a variety of industries such as the rubber industry, fertilizer manufacturing, oil refining, wastewater processing, and mineral extraction. The gasifier produces a molten slag that flows freely into a water-filled compartment at the bottom of the gasifier. As the molten slag contacts the water bath, the slag vitrifies into dense, glassy granules. The vitrified slag produced by the gasifiers can be used for the fabrication of ceramic products.

4.1.8 Coal Technology Options

Ultra-Supercritical (USC) Pulverized Coal (PC)

The following assumptions have been made for all ultra-supercritical PC options:

1. Single unit site, with a capacity of 900 MW net (nominal).
2. USC TC4F STG and USC PC boiler.
3. AQCS:
    - Low nitrogen oxide (NO_x) burners and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control.
    - Wet flue gas desulfurization (FGD) for sulfur dioxide (SO_2) control.
    - Activated carbon injection for mercury control.
    - Pulse-jet fabric filter for particulate matter (PM10) control.
    - Sorbent injection for sulfur trioxide (SO_3) control.
4. Turbine driven boiler feed pumps.
5. Throttle conditions – 3,800 psia (pounds per square inch absolute)/1,110° F main steam/1,110° F reheat.
6. Single reheat steam cycle.
7. Eight feedwater heaters – Three high-pressure (HP), four low-pressure (LP), and one deaerator (DA).
8. Ultra-supercritical PC options that employ carbon dioxide (CO_2) capture and compression (CCC) would utilize an amine-based chemical solvent to remove 90 percent of the CO_2 from the flue gas stream. Staged compression would deliver the CO_2 to the site boundary at a pressure of 2,200 psig (pounds per square inch gauge). CO_2 transportation and sequestration are evaluated separately.

Oxyfuel Coal

The following assumptions have been made for all oxyfuel coal options:

1. Single unit site, with a fuel flow rate equal to the fuel flow rate for the ultra-supercritical PC plant (Refer to Section 3.2.1).
2. USC TC4F STG and USC PC boiler.
3. AQCS:
    - Low NO_x burners and SCR for NO_x control.
    - Wet FGD for SO_2 control.
    - Activated carbon injection for mercury control.
    - Pulse-jet fabric filter for particulate control.
    - Sorbent injection for SO_3 control.

• 90 percent of the flue stream would be compressed and delivered to the site boundary at a pressure of 2,200 psig. CO_2 transportation and sequestration are evaluated separately.
4. Flue gas recycle.
5. Air Separation Unit (ASU) – 95 percent oxygen (O2) purity.
6. Turbine driven boiler feed pumps.
7. Throttle conditions – 3,800 psia/1,110° F/1,110° F.
8. Single reheat steam cycle.
9. Eight feedwater heaters – Three HP, four LP, and one DA.

Circulating Fluidized Bed (CFB)

The following assumptions have been made for all CFB options:

1. Single unit site, with a capacity of 2 x 300 MW net (nominal) boilers and 1 x 600 MW net (nominal) TC4F STG.
2. AQCS:
    - Combustion controls and selective noncatalytic reduction (SNCR) for NO_x control
    - Boiler limestone injection and polishing spray dry absorber for polishing SO_2/SO_3 control.
    - Activated carbon injection for mercury control.
    - Pulse-jet fabric filter for particulate control.
3. Motor driven boiler feed pumps.
4. Single reheat steam cycle.
5. Eight feedwater heaters – Three HP, four LP, and one DA.
6. A mechanical-draft, counterflow, cooling tower assumed for heat rejection.
7. CFB options that employ CCC would utilize an amine-based chemical solvent to remove 90 percent of the CO_2 from the flue gas stream. Staged compression would deliver the CO_2 to the site boundary at a pressure of 2,200 psig. CO_2 transportation and sequestration are evaluated separately.

Subcritical CFB

1. Subcritical STG and subcritical CFB boilers.
2. Throttle conditions – 2,415 psia/1,050° F/1,050° F.

Supercritical CFB

1. Supercritical STG and supercritical CFB boilers.
2. Throttle conditions – 3,800 psia/1,050° F/1,050° F.

Integrated Gasification Combined Cycle (IGCC)

The following assumptions have been made for all integrated gasification combined cycle (IGCC) options:

1. Two 50 percent dry fed, entrained-flow Shell Coal Gasification Process gasifiers.
2. Two General Electric (GE) 7FB[8] combustion turbine generators (CTGs) with syngas combustors.
3. Two 50 percent ASUs – 95 percent O_2 purity.
4. One subcritical TC2F STG.
5. Two triple-pressure heat recovery steam generators (HRSGs).
6. AQCS:
    - Nitrogen diluent, syngas saturation, and SCR for NO_x control.
    - Carbonyl sulfide (COS) hydrolysis, Selexol acid gas removal (AGR), and Claus sulfur recovery unit (SRU) with tailgas recycle for SO_2 control and sulfur recovery.
    - Candle filter for particulate control.
    - Sulfided carbon bed adsorption for mercury control.
7. Inlet air evaporative cooling above 59° F.
8. A mechanical-draft, counterflow, cooling tower assumed for heat rejection.
9. No duct firing for the HRSG(s).
10. IGCC options that employ CCC would utilize a Genosorb physical solvent CO_2 removal process to remove 90 percent of the CO_2 from the syngas stream. Rather than a Selexol process, options that employ CCC would utilize an MDEA (methyl diethanolamine) acid gas removal process. Staged compression would deliver the CO_2 to the site boundary at a pressure of 2,200 psig. CO_2 transportation and sequestration are evaluated separately.

Efficiency Improvements – Duct Draft Reductions[9]

The electrical auxiliary loads required to drive the forced draft (FD) and induced draft (ID) fans are significant in a PC plant. Any reductions in air handling system pressure loss will reduce the required auxiliary loads and, therefore, increase the net plant output (NPO).

One method of calculating reduced pressure loss potential in the air handling system is to perform cold flow modeling. According to Pollution Control Services, Inc. (PCS), implementing modifications identified from modeling flows from the boiler economizer through the SCR, air heater, ESP/baghouse, scrubber, ID fans and stack will typically result in overall static loss reductions of 3 to 8 inches of water column (in-wc). Using the information provided by PCS, Black & Veatch made a conservative assumption that five

[8] Future offerings will be presented as “7FA Syngas.”
[9] 4 CSR 240-22.040(4)

flow correction devices could be installed in each Ameren Missouri PC unit. Flow correction devices attempt to restrict or divert the flows in an attempt to achieve more uniform flow distribution and lower pressure drop. Some examples of flow correction devices include turning vanes, splitters, egg crates, and perforated plates.

Assuming an average static loss reduction of 0.4 in-wc per flow correction device results in an overall pressure loss reduction of 2.0 in-wc per unit. A reduction in pressure loss would result in auxiliary load savings through the ID fan(s), increasing net output. Using Ameren Missouri unit operating data, Black & Veatch estimated ID fan auxiliary load savings for a 2.0 in-wc pressure drop reduction for Rush Island Unit 2. The performance gains realized at Rush Island Unit 2 are representative of a ~ 600 MW pulverized coal unit.

An order-of-magnitude capital cost estimate was developed using information provided by PCS and recent Black & Veatch experience with such flow correction devices. PCS suggested budget cost of $400,000 to $500,000 for 1:12 scale cold flow modeling of Rush Island Units 1 and 2. Translated roughly, this equates to about $250,000 for cold flow modeling at Rush Island Unit 2 only. Recent installations of flow correction devices in nominal 500 MW – 600 MW pulverized coal plants have ranged in cost from approximately $40,000 to $65,000 per flow correction device. With the fixed expense of cold flow modeling, modifications made to the larger units will most likely be the most economical.

Efficiency Improvements – Condenser Back-Pressure Reductions[10]

The performance of a condenser impacts STG performance, thereby, affecting unit performance. Unit performance can be improved by increasing the condenser cleanliness factors for plants utilizing once-through cooling systems. Debris filters can reduce macro fouling and tubesheet pluggage in the condenser. Two types of debris filters may be applied:

- In-line debris filter – placed in the circulating water pipe near the condenser waterbox.
- Intake debris filter – placed at the intake structure and intended to replace the traveling screens.

Costs for intake debris filters were developed for this analysis. The capital cost requirements are greater for intake debris filters than for in-line debris filters. However, with the implementation of in-line debris filters, it is recommended that traveling screens remain in service. Traveling screens tend to have significant problems with carryover of debris and are maintenance intensive. Intake debris filters are intended to replace

[10] 4 CSR 240-22.040(4)

traveling screens, likely reducing total system maintenance requirements and improving overall unit reliability.

Black & Veatch believes that implementation of a condenser ball cleaning system, in conjunction with debris filters, is the best approach to realizing significant condenser performance improvements.

Black & Veatch spoke with Ameren Missouri engineers and utilized on-line Ameren Missouri unit operating data and equipment design information to develop a performance impact estimate for Rush Island Unit 2. A cost estimate for the intake debris filters and condenser ball cleaning systems was developed from multiple vendor budgetary quotations. The performance impact estimate represents average condenser cleanliness factor increases of 25 percentage points for each hour Rush Island Unit 2 would operate above the design condenser backpressure assuming an existing condenser cleanliness factor of 60 percent. The performance and cost estimates for Rush Island Unit 2 are representative of a ~ 600 MW pulverized coal unit.

4.1.9 Natural Gas Technology Options

Meramec Unit 4 STG in Combined Cycle Conversion

The reuse of Unit 4's STG as part of a combined cycle was included as an alternative to replacing Units 1 through 4 with an entirely new unit at Meramec. Reuse of the Unit 4 STG would entail the addition of three CTGs, each fitted with a Heat Recovery Steam Generator (HRSG). Steam produced in the HRSGs would be sent to the Unit 4 STG. Each of the HRSGs would be outfitted with duct firing to fully utilize the STG capacity. The following assumptions have been made for the Meramec Unit 4 STG combined cycle conversion option:

1. Three Siemens 501F CTGs and three HRSGs supplying steam to the existing Unit 4 STG.
2. AQCS:
    - Dry low NO_x burners and SCR for NO_x control.
    - CO oxidation catalyst for carbon monoxide (CO) and volatile organic compounds (VOC) controls.
3. Inlet air evaporative cooling above 59° F.
4. Duct firing during hot day conditions to match the design limits of the Unit 4 STG.
5. Triple-pressure HRSGs.
6. No HRSG bypass dampers and stacks included.
7. Existing equipment removed from service:
    - Unit 4 boiler.
    - Unit 4 feedwater heaters.
    - Unit 4 boiler feed pump(s).
    - Existing Unit 4 feedwater and steam piping.

- Plant control system.
- Unit 4 electrostatic precipitator (ESP).
- Unit 4 coal and limestone handling equipment.
- Units 1 through 3 in their entirety.

8. Equipment reused in combined cycle conversion:
    - Unit 4 STG.
    - Unit 4 STG control system.
    - Unit 4 gland steam condenser.
    - Unit 4 gland steam regulator.
    - Unit 4 condenser.
9. Scope of work needed to refurbish reused equipment:
    - STG intermediate pressure (IP) retrofit.
    - STG high pressure (HP) stator rewind and rotor replacement.
    - STG low pressure (LP) stator rewind and rotor replacement.
    - STG static excitation retrofit.
    - Condenser retubing.

Meramec Boiler Conversion to Natural Gas

The following scope of work applies to the Meramec Unit 3 and 4 options in which the boilers would be converted to burn natural gas:

1. Burner replacement.
2. Reheater modifications.
3. Superheater modifications.
4. Desuperheater spray modifications.
5. Air heater modifications.
6. Boiler controls modifications.

Meramec Boiler Replacements and STG Rebuilds

The following scope of work applies to the Meramec Unit 3 and 4 options in which the boilers would be replaced and the STG sets would be refurbished:

1. Boiler - New waterwalls.
2. Boiler - Major superheater and reheater retrofits.
3. Steam piping modifications (main steam, cold reheat, and hot reheat).
4. Feedwater system modifications.
5. Hot well pump overhaul.
6. DA replacement (excluding DA storage tank).
7. One feedwater heater replacement.
8. Condenser retubing.
9. Induced draft fan motor and rotor modifications.
10. Water cannon replacement.

11. Unit-specific bottom ash system.
12. Fly ash collection system.
13. Significant structural steel modifications.
14. Demolition.
15. STG intermediate pressure (IP) retrofit.
16. STG high pressure (HP) stator rewind and rotor replacement.
17. STG low pressure (LP) stator rewind and rotor replacement.
18. STG static excitation retrofit.

Combined Cycle

Performance, emissions, and cost estimates were prepared for the following combined cycle technology:

- 2-on-1 Siemens combined cycle based on a Siemens 501F CTG.

The following assumptions have been made for all combined cycle options:

1. Two CTGs, two HRSGs, and one TC2F STG.
2. AQCS:
   - Dry low NO_x burners and SCR for NO_x control.
   - CO oxidation catalyst for CO and VOC controls.
3. Inlet air evaporative cooling above 59° F.
4. Duct firing during hot day conditions to match 600 MW net plant output.
5. Triple-pressure HRSGs.
6. A mechanical-draft, counterflow, cooling tower assumed for heat rejection.
7. No HRSG bypass dampers and stacks.
8. Combined cycle options that employ CCC would utilize an amine-based chemical solvent to remove 90 percent of the CO_2 from the flue gas stream. Staged compression would deliver the CO_2 to the site boundary at a pressure of 2,200 psig. CO_2 transportation and sequestration are evaluated separately.

Venice Combined Cycle Conversion

Performance, emissions, and cost estimates were developed as part of a separate study conducted by Black & Veatch for Ameren Missouri. The conversion of Venice units 3 and 4 from two Siemens Westinghouse 501F combustion turbines to a 2-on-1 combined cycle required the following additional systems:

- Two HRSGs and one TC2F STG.
- Duct firing during hot day conditions to match the 600 MW net plant output.
- Triple-pressure HRSGs.
- A mechanical-draft, plume abated cooling tower assumed for heat rejection.

The conversion of two simple cycle combustion turbines into a 2-on-1 combined cycle block represents a net capacity increase. In addition, the combined cycle would likely be dispatched more frequently than the current simple cycles, resulting in a net increase in fuel consumption and operations expenses. For screening purposes, the Venice combined cycle conversion option is treated as an incremental capacity increase to exiting Venice Units 3 and 4 with fuel burn rate and fixed and non-fuel variable O&M estimates equal to the entire 2-on-1 combined cycle block. For modeling purposes, the Venice combined cycle conversion is treated as a 2-on-1 combined cycle block. All model runs with the Venice combined cycle block exclude the existing Unit 3 and 4 simple cycles. All model runs with the existing Unit 3 and 4 simple cycles exclude the Venice combined cycle block.

Fuel Cell

Performance, emissions, and cost estimates were prepared for the following fuel cell technology:

- Generic, molten carbonate fuel cells.

The following assumptions have been made for the gas-fueled fuel cell facility:

1. Thirty-six (36) 2.8 MW (net, nominal) fuel cell packages.

Combined Cycle Reciprocating Engines

Performance, emissions, and cost estimates were prepared for the following reciprocating engine technology:

- Wärtsilä 20V34SG

The following assumptions have been made for the gas-fueled combined cycle reciprocating engine facility:

1. NO_x reduction would be achieved through use of a urea-based SCR system located in the HRSGs.
2. The power block would consist of two 20V34SG engines, one nonreheat STG, and two HRSGs.
3. A mechanical-draft, counterflow cooling tower would be included.

Cheng Cycle

Performance, emissions, and cost estimates were prepared for the following combustion turbine technology:

- GE 7EA

The following assumptions have been made for the gas-fueled Cheng Cycle facility:

1. The power block would consist of one modified GE 7EA CTG and one HRSG.
2. Emissions would be controlled through the use of Cheng Low NO_x (CLN) combustion with steam/fuel premixing.
3. Power augmentation would be achieved through use of the Advanced Cheng System (ACS) and Cheng Boost steam injection.

Simple Cycle

Performance, emissions, and cost estimates were prepared for the following simple cycle technologies:

- Large Frame – Siemens 501F.
- Small Frame – GE 7EA.
- Aeroderivative – GE LM6000 SPRINT.

The following assumptions have been made for all simple cycle options:
1. Dry low NO_x (DLN) burners would be included for NO_x control.
2. Units that are dispatched at a capacity factor of 5 percent would not include an SCR system or CO oxidation catalyst.
3. Units that are dispatched at a capacity factor of 10 percent would include an SCR system and CO oxidation catalyst.

Existing Simple Cycle Fleet Power Augmentation[11]

Characteristics for simple cycle power augmentation options were developed as part of a separate study conducted by Black and Veatch. The objective of this study was to identify a single preferred power augmentation technology for the block of turbines located at each facility. The study considered the following commercially available power augmentation technologies:

- Wetted Media Evaporative Cooling.
- Inlet Fogging Evaporative Cooling.
- Wet Compression.
- Inlet Chilling.
- Inlet Chilling with Thermal Storage.
- Water Injection.
- Steam Injection.
- GE SPRINT Package.

In total, 38 CTs distributed among seven sites were analyzed to determine the feasibility of installing various commercially available power augmentation technologies. The results of the power augmentation technology screening are presented in Table 4.B.6.

[11] 4 CSR 240-22.040(4)

Table 4.B.6 CTG Power Augmentation Summary of Results

Facility	Number of Units	Preferred Power Augmentation	Potential Unit Net Capacity Increase, MW	Potential Site Net Capacity Increase, MW	Incremental Capital Cost, $/kW
Audrain	8	Inlet Chilling	8.4	67.2	850
Goose Creek	6	Wetted Media	3	18	150
	6	Inlet Chilling	11	66	600
Kinmundy	2	None	N/A	N/A	N/A
Peno Creek	4	Inlet Chilling	5	20	1,200
Pinckneyville 1-4	4	SPRINT Package	6	16	300
Pinckneyville 5-8	4	Inlet Fogging	2	8	150
	4	Inlet Chilling	5	20	850
Raccoon Creek	4	Inlet Chilling	8	32	900
Venice 2	1	Inlet Chilling	5	5	1,200
Venice 5	1	None	N/A	N/A	N/A

The two options included from that study were selected on the basis of cost of power and capacity addition potential. The first option selected is the addition of wetted media (commonly referred to as evaporative cooling) to six GE 7EA combustion turbines at Ameren Missouri's Goose Creek facility. The second option selected is the addition of inlet chilling to the 7EAs at Goose Creek. The first power augmentation option offers the lowest cost on a dollar per kW basis at $150/kW with 3MW capacity increase on each of the six units. However, the second option offers a more substantial capacity increase- a total increase of 66 MW, but at a higher cost- $600/MW.

Reciprocating Engines (Simple Cycle)

Performance, emissions, and cost estimates were prepared for the following reciprocating engine technology:

• Wärtsilä 20V34SG

The following assumptions have been made for the gas-fueled reciprocating engine facility:

1. Units would be dispatched at a low capacity factor that would preclude SCR.
2. The power block would consist of twelve 20V34SG engines, for a 100 MW net (nominal) output.

No additional operational characteristics, constraints or siting impacts that could affect the screening results were identified. By the same token, no other technology 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

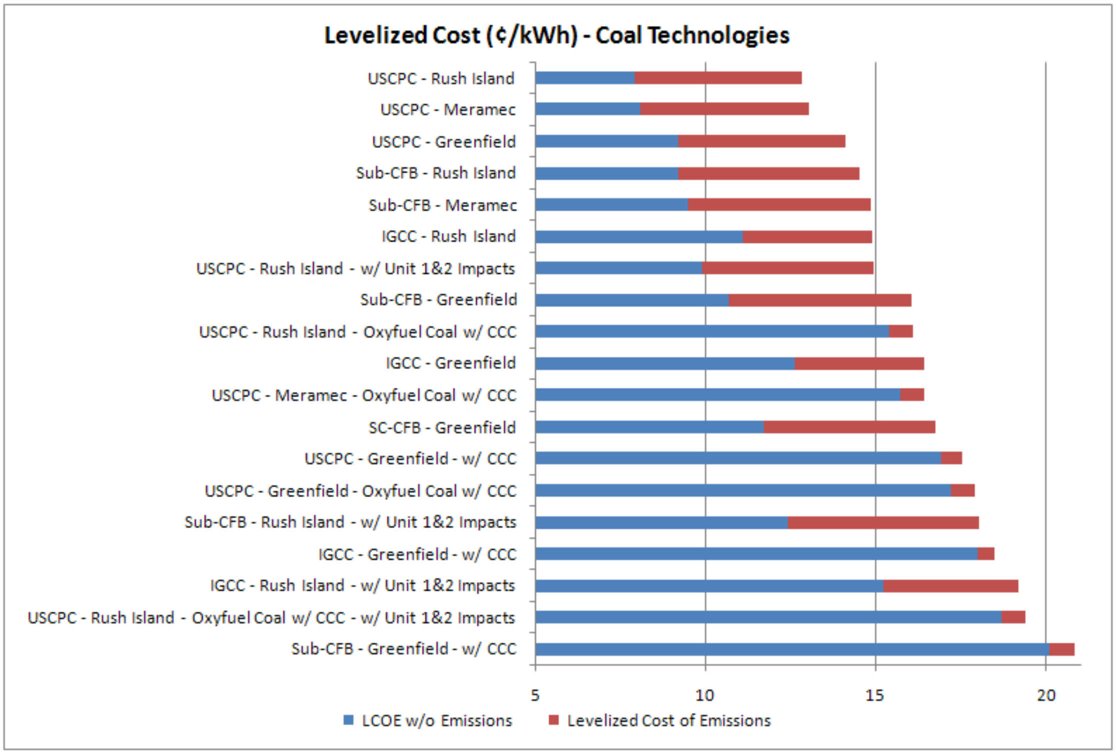
Annual costs for the LCOE estimates include levelized annual capital cost, fixed and variable O&M, fuel cost, and emissions allowances if applicable; LCOE estimates were developed in three different ways: without emission costs, with emissions costs for SO_2 and NO_x, and with emissions costs for SO_2,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

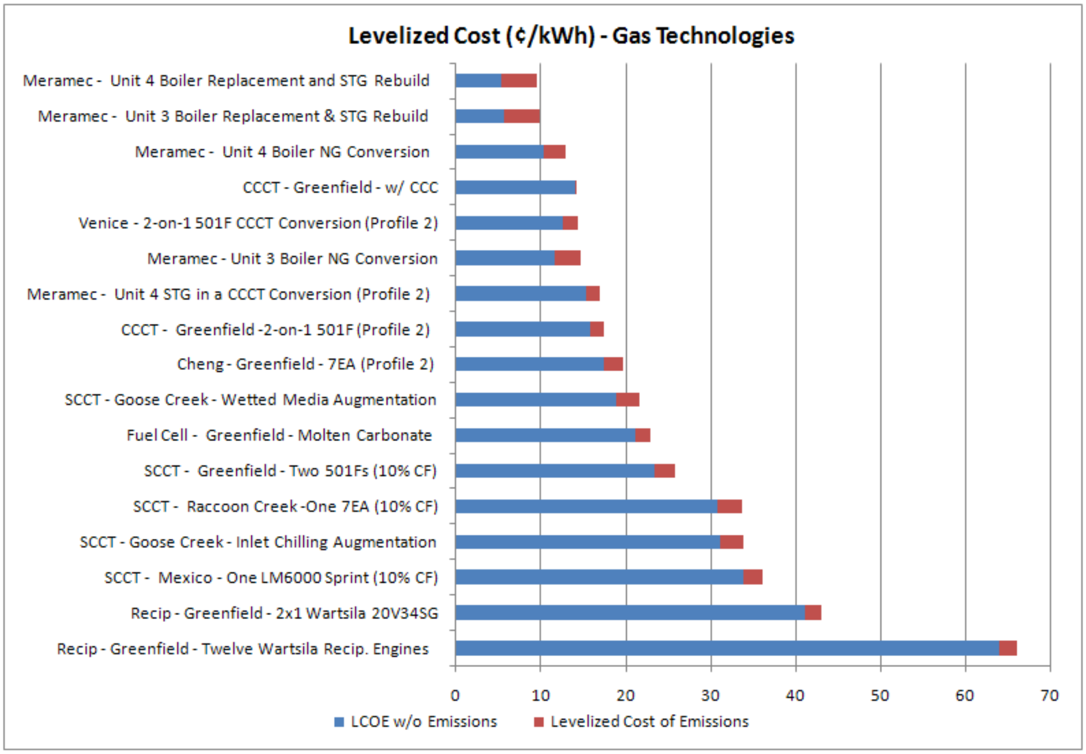
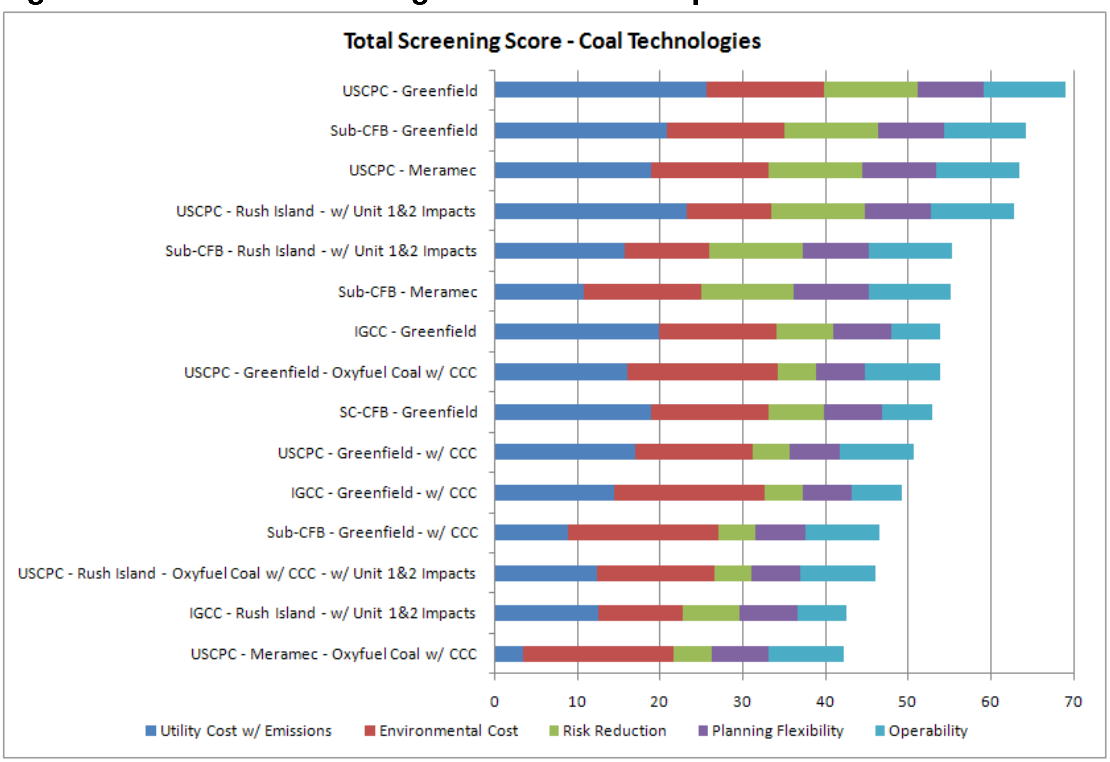
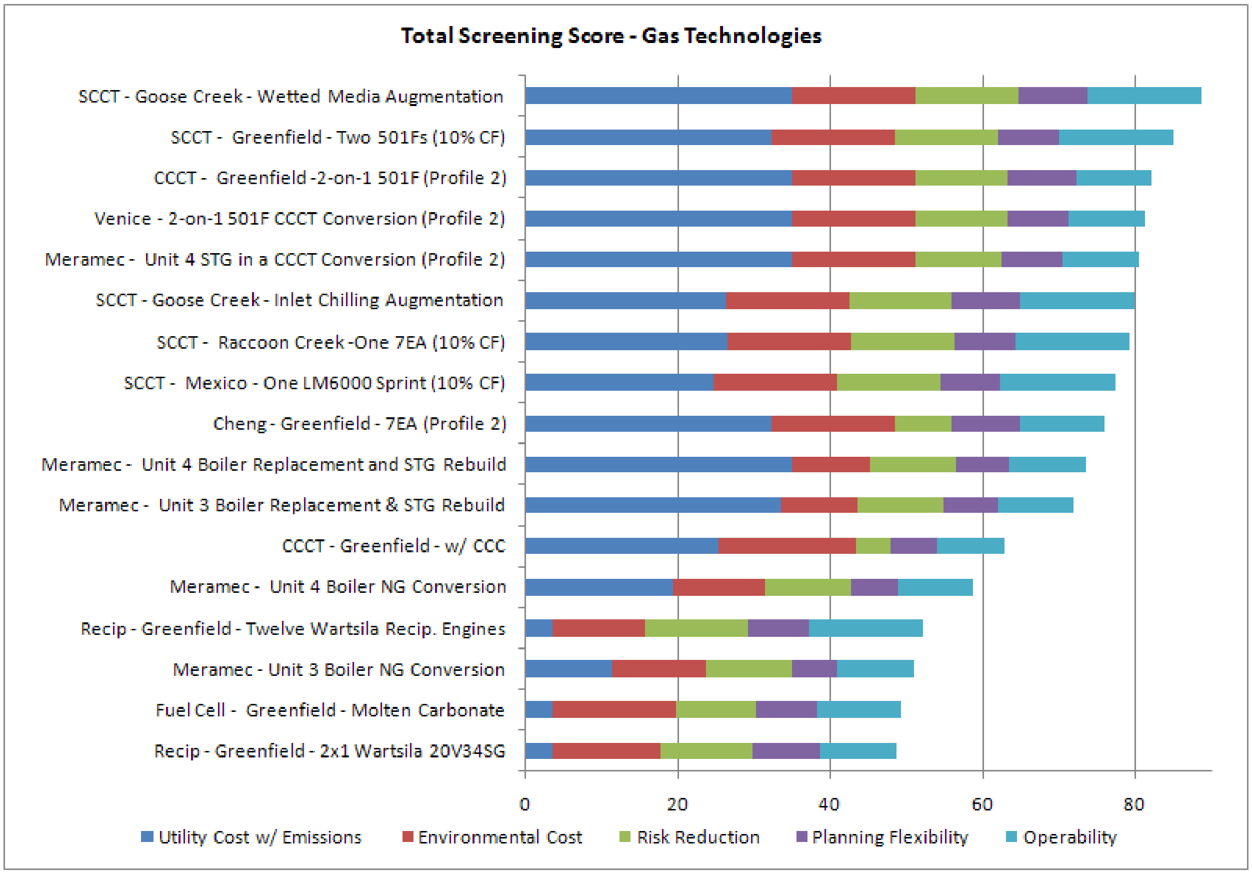


Figure 4.B.3 Total Screening Score for Coal Options[19]



[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	7.36	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	96	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% Cl	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