# Chapter 6 - Appendix B

## Characterization – Thermal Resources

## 6.1 Coal and Natural Gas Options[1]

### Preliminary Screening Analysis[2]

| 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 | Efficiency Improvements to Existing Plants – Duct Draft Reductions | ✗ |
| Coal | Efficiency Improvements to Existing Plants – Condenser Back-pressure Reductions | ✗ |
| Gas | Greenfield - 2-on-1 501F CCCT | ✓ |
| Gas | Greenfield – 2-on-1 Wartsila 20V34SG Combined Cycle Reciprocating Engine | ✗ |
| Gas | Greenfield - CCCT Amine-Based Post-Combustion CCC | ✗ |
| Gas | Greenfield – GE 7EA Cheng Cycle | ✗ |
| Gas | Greenfield - Molten Carbonate Fuel Cell | ✗ |
| Gas | Greenfield - Twelve Wartsila 20V34SG Simple Cycle Reciprocating Engines | ✗ |
| Gas | Greenfield - Two 501F SCCTs (10% CF) | ✗ |
| Gas | Greenfield - Two 501F SCCTs (5% CF) | ✓ |
| 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) | ✗ |

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

## 6.1.1 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:

- 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.

### 6.1.1.1 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 on Ameren Missouri's ability to plan for and reasonably implement the technology. Table 6B.1 provides a summary of approximate size limitations for new generation units.

**Table 6B.1 Capacity Ranges**

| Technology Description | Single Unit Size | |
|---|---|---|
| | Lower Range (MW) | Upper Range (MW) |
| Ultra-Supercritical PC | 500 | 1,000 |
| Oxyfeul 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 6B.12 and Table 6B.13 under the Supporting Tables section.

#### 6.1.1.2 Commercial Availability

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

#### 6.1.1.3 Capital Cost Estimates

Screening level, overnight EPC capital cost estimates were developed for all evaluated options and expressed in 2013 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 6B.14 and Table 6B.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 6B.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 6B.2 Potential Items for Owner's Costs**

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

#### 6.1.1.4 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 6B.14 and Table 6B.15. First year O&M costs (in 2013 $s) were estimated, and for the future years 2% escalation rate was used.

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

Baseload Dispatch Profiles – 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.

Intermediate Load Dispatch Profiles – 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.

Peaking Load Dispatch Profiles – 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.

### 6.1.1.5 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 6B.3.

**Table 6B.3 Scheduled Maintenance Outage Patterns**

| 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 |
| Supercritical Circulating Fluidized Bed (Note 2) | 3-3-3-3-3-6 |
| Combined Cycle Combustion Turbine (Note 4) | 1-1-2-1-1-6 |
| Molten Carbonate Fuel Cells (Note 5) | 1 |
| Combined Cycle Reciprocating Engine (Note 6) | 2-3-2-3-2-4 |
| Cheng Cycle – 7EA (Note 7) | 1-1-2-1-1-4 |
| Siemens 501F (Note 8) | 1-2-1-4 |
| GE LM6000 Sprint (Note 9) | 1-10 |
| GE 7EA (Note 7) | 1-1-2-1-1-4 |
| Wartsila 20V34SG Reciprocating Engine (Simple Cycle) (Note 6) | 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) 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.
(5) Short outages required every 2,000 to 3,000 hours of operation.
(6) 2 week per 8,000 hours, 3 weeks per 16,000 hours, and 4 weeks per 48,000 hours.
(7) 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.
(8) Siemens recommends the following: 1 week combustion inspection every 400 starts, 2 week hot gas path inspection every 800 starts, and a 4 week major inspection every 1,600 starts.
(9) 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 6B.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 6B.4 Forced Outage Rates**

| Technology Description | EFOR, % | EFORd, % |
|---|---|---|
| Ultra-Supercritical PC | 8% | 8% |
| Subcritical Circulating Fluidized Bed | 11% | 10% |
| Integrated Gasification Combined Cycle | 13% | 13% |
| 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% |
| Wartsila 20V34SG Reciprocating Engine (Simple Cycle) | 23% | 4% |

### 6.1.1.6 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 6B.5 presents a summary of the production of wastewater and solid wastes for the evaluated options.

**Table 6B.5 Waste Generation**

| Technology Description | Wastewater, gpm | Solid Waste, tons/year |
|---|---|---|
| 900 MW - Ultra-Supercritical PC | 1,200 | 274,000 |
| 620 MW - Oxyfuel Coal | 3,300 | 274,000 |
| 679 MW - Ultra-Supercritical PC with 90% Post CCC | 3,300 | 274,000 |
| 600 MW - Subcritical Circulating Fluidized Bed | 1,000 | 278,000 |
| 453 MW - Subcritical CFB with 90% Post CCC | 2,500 | 278,000 |
| 562 MW - Integrated Gasification Combined Cycle | 900 | 104,000 |
| 493 MW – IGCC with 90% Pre CCC | 2,400 | 108,000 |
| 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 |
| 99 MW - Wartsila 20V34SG Reciprocating Engine (Simple Cycle) | Negligible | Negligible |

#### 6.1.1.7 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 flue-gas desulfurization (FGD) operation, and byproducts from coal gasification.

- Fly Ash – The most widely known uses for fly ash are in the cement and concrete industries. More than half of the concrete produced today in the U.S. uses fly ash in some quantity as a substitute for traditional cement. 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 in asphalt and as an ingredient in waste stabilization and/or solidification.

- Bottom Ash – Bottom ash is widely utilized in road bases and structural fill projects. Other applications include use as a component of blasting grit, 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 eventually 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.

- 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.

The potential for the use of these solid materials has been reduced by the 2010 proposed Federal rule which included considering managing these materials as a hazardous waste. The rule would have allowed some beneficial uses to continue, but the stigma of possible hazardous waste regulation has already caused a drop in the beneficial uses of these materials. A final Federal coal combustion residuals rule is expected in December 2014; however, management of these materials under the hazardous waste regulation is no longer expected, but some changes are expected in our ability to beneficially use them.

#### 6.1.1.8 Coal Technology Options[3]

#### Ultra-Supercritical (USC) Pulverized Coal (PC)

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

[3] 4 CSR 240-22.040(1)

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.
9. Costs based on PRB coal capability only.

### 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 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

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 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

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 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.

### 6.1.1.9 Natural Gas Technology Options[4]

### 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.

(Note: High efficiency "H" Class turbines will likely be available in the future. Ameren Missouri is continually evaluating new technologies.)

### 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.

[4] 4 CSR 240-22.040(1)

### 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.

(Note: High efficiency "H" Class turbines will likely be available in the future. Ameren Missouri is continually evaluating new technologies.)

### 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.

## 6.1.2 Preliminary Screening Analysis

### Preliminary Screening Methodology[5]

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. For the 2014 IRP, Ameren Missouri subject matter experts reviewed the scoring criteria and the technology scores were revised as needed. Categories and criteria, along with their assigned weightings, are presented in Table 6B.7.

[5] 4 CSR 240-22.040(2)

## Table 6B.7 Scoring Criteria

| Category/Criteria | Category/Criteria Weighting | Scoring Basis Guidelines |
|---|---|---|
| **Utility Cost** | **35** | |
| Levelized cost of energy | 90 | 100 - Lower 5 percentile.<br>90 to 10 - 5 to 95 percentile, linearly scaled.<br>0 - Upper 5 percentile. |
| Specificity of location | 10 | 100 - Within Ameren Missouri service territory.<br>50 - Within MISO<br>0 - Outside MISO |
| **Environmental Cost** | **20** | |
| Currently meets regulated emissions limits | 60 | 100 - Produces no emissions.<br>85 - Ability to meet emissions limits.<br>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.<br>75 - May require controls for 2 major pollutants.<br>50 - May require controls for 3 major pollutants.<br>25 - May require controls for 4 major pollutants.<br>0 - May require controls for 5 or more major pollutants. |
| **Risk Reduction** | **15** | |
| Technology status | 60 | 100 - Commercially proven.<br>50 - Demonstration.<br>25 - Developmental with positive trend.<br>0 - Developmental with negative trend. |
| Constructability | 20 | 100 - Less labor, material and equipment risk.<br>50 - Moderate labor, material & equipment risk.<br>25 - More labor, material and equipment availability risk. |
| Safety training requirements | 20 | 100 - Minimal requirement & hazards.<br>50 - Industry standard for baseload generation in safety training and hazards.<br>0 - Unique requirements and/or hazards. |
| **Planning Flexibility** | **15** | |
| Permitting | 10 | 100 - Less extensive permitting.<br>50 - Moderate permitting.<br>25 - More extensive permitting. |
| Schedule Duration | 10 | 100 - Lower 5 percentile.<br>90 to 10 - 5 to 95 percentile, linearly scaled.<br>0 - Upper 5 percentile. |
| Fuel Flexibility | 25 | 100 - No fuel required.<br>50 - Multiple fuels, multiple sources.<br>25 - Multiple fuels and single source or single fuel and multiple sources.<br>0 - Single fuel, single source. |
| Scalability/Modularity/Resource Constrained | 20 | 100 - Has no constraints.<br>75 - Has one constraint.<br>25 - Has two constraints.<br>0 - Is constrained by scalability, modularity, and resource availability. |
| Transmission Complexity | 15 | 100 - Requires less redundancy, less planning.<br>50 - Require more redundancy, more planning |
| Construction Schedule and Budget Risk | 20 | 100 - Cost or schedule uncertainty.<br>75 - Cost and schedule uncertainty.<br>50 - Cost and schedule uncertainty with limited industry experience.<br>25 - Major cost and schedule uncertainty.<br>0 - Major cost and schedule uncertainty with limited industry experience. |
| **Operability** | **15** | |
| Availability | 50 | 100 - Equivalent Availability factor ≥ 85%<br>50 - Equivalent Availability factor ≤ 85% |
| Technical Operability Training | 15 | 100 - Minimal technical operability management (TOM).<br>50 - Moderate TOM<br>25 - Moderate TOM and advanced technology.<br>0 - Unique experience and management requirements for operation. |
| Load-Following/VAR Support | 35 | 100 - Load-following and reactive power support capabilities.<br>50 - Load-following or reactive power support capabilities.<br>25 - Moderate load-following or reactive power support capabilities.<br>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 – 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 6B.8.

**Table 6B.8 Emissions Costs and Escalation Rates**[6]

| | SO2 | NOx Annual | NOx Seasonal | CO2 |
|---|---|---|---|---|
| **2013 $/ton** | $1.50 | $40.00 | $20.50 | $5.34 |
| **Escalation** | 0.0% | 0.0% | 0.0% | 2.00% |
| **Source** | Internal Subejct Matter Expert Based on CAIR not CSAPR | | | 2013 Synapse Carbon Dioxide Price Forecast, Nov 2013. (CO2 Prices begin in 2025) |

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.

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 6B.9 and Table 6B.10.

[6] 4 CSR 240-22.040(5)(D)

**Table 6B.9 Fuel Prices for LCOE Estimates**

| Location | Greenfield | Greenfield |
|---|---|---|
| **Type** | PRB Coal | Natural Gas |
| **2013 $/MMBtu** | $1.99 (Varies) | $3.87 (Varies) |
| **Escalation** | 4.3% (Varies) | 3.8% (Varies) |

**Table 6B.10 Financial Inputs for LCOE Estimates**

| Technology | Tax Life Years | Economic Life Years | LFCR Percent | PWDR Percent |
|---|---|---|---|---|
| PC (USPC) | 20 | 40 | 10.20 | 6.46 |
| CFB (Sub-CFB) | 20 | 40 | 10.20 | 6.46 |
| IGCC | 20 | 30 | 10.89 | 6.46 |
| Simple Cycle (SCCT) | 15 | 30 | 10.55 | 6.46 |
| Combined Cycle (CCCT) | 20 | 30 | 10.89 | 6.46 |
| Fuel Cells | 15 | 20 | 12.23 | 6.46 |
| Gas Reciprocating | 15 | 30 | 10.55 | 6.46 |

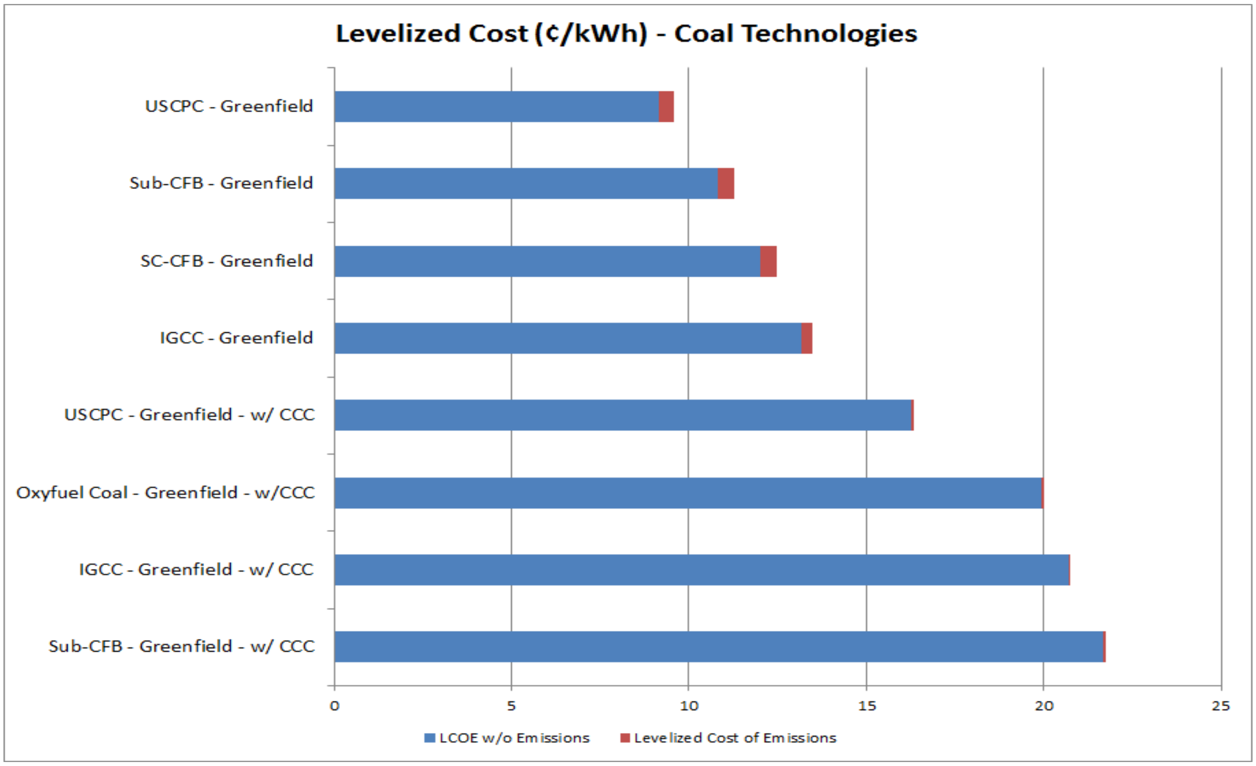
Annual costs for the LCOE estimates include levelized annual capital cost, fixed and variable O&M, fuel cost, and emissions allowances if applicable; LCOE estimates were developed in three different ways: without emission costs, with emissions costs for $SO_2$ and $NO_x$, and with emissions costs for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

### Preliminary Screening Results[7]

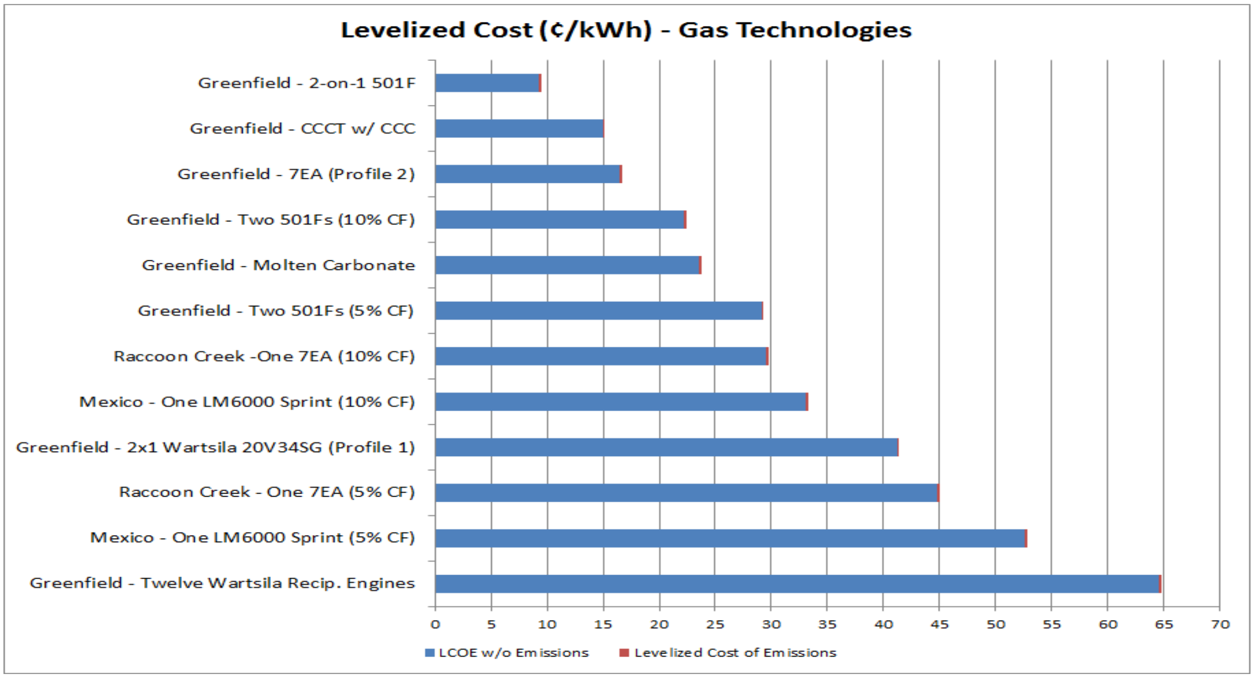
The levelized costs of energy and overall scorings of the evaluated options are presented in Table 6B.20a, Table 6B.20b, Table 6B.21a and Table 6B.21b. All levelized costs of energy and overall scorings are presented with and without $SO_2$, $NO_x$, and $CO_2$ price forecasts included. The following figures show the LCOE and total screening scores.

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

## Figure 6B.1 LCOE for Coal Options[8]

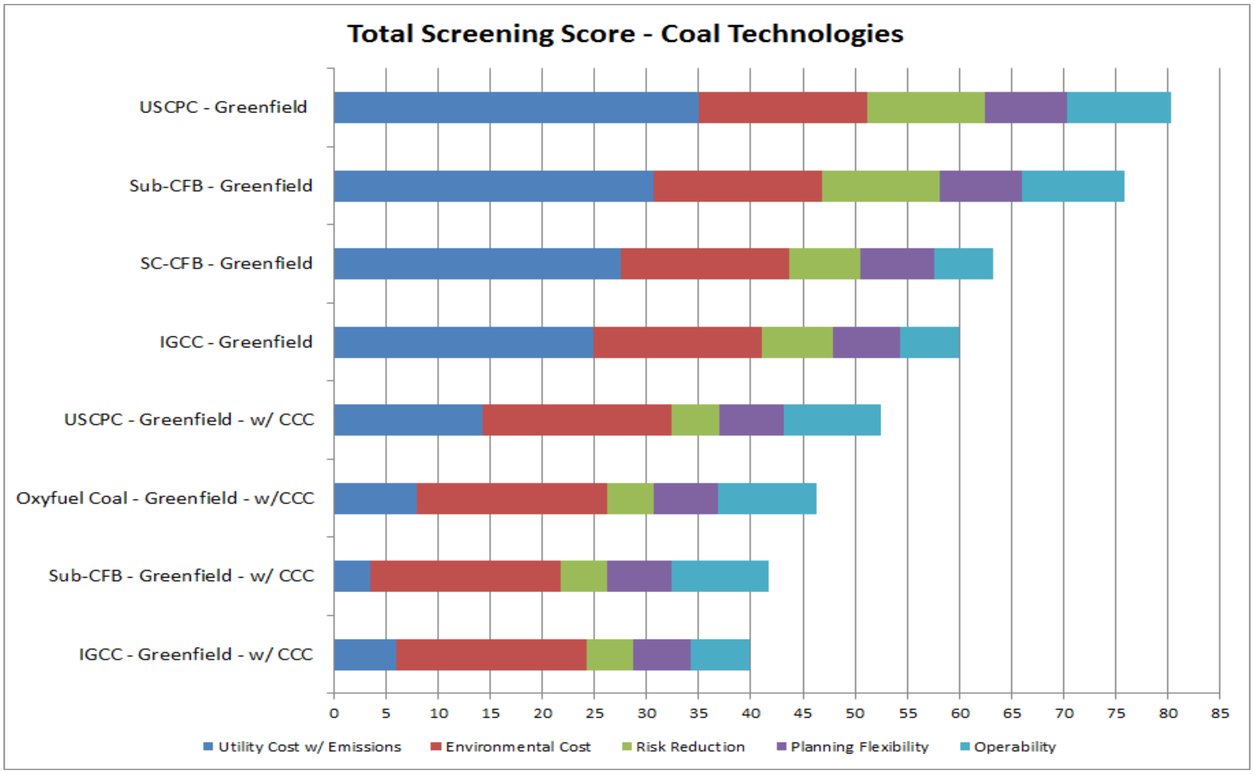



## Figure 6B.2 LCOE for Gas Options

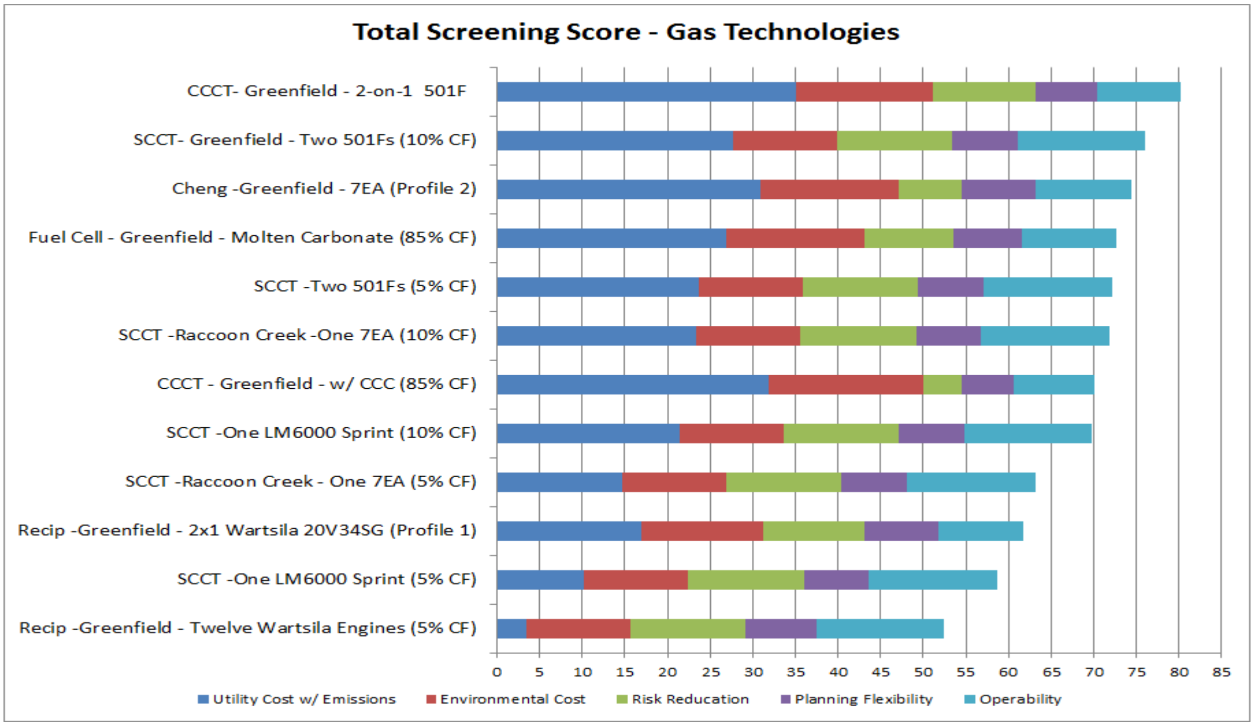



[8] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(C)

## Figure 6B.3 Total Screening Score for Coal Options[9]




## Figure 6B.4 Total Screening Score for Gas Options[10]




[9] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(C)
[10] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(C)

### 6.1.3 Candidate Options

Using the preliminary screening results as a tool, Ameren Missouri selected three technologies to be characterized further. Table 6B.11 presents a listing of the potential candidate options.

**Table 6B.11 Candidate Options**[11]

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

## 6.2 Nuclear Options[12]

### 6.2.1 AP1000 Characterization

***Design Parameters***

Key AP1000 design parameters include the following:

Design life - 60 years
- Thermal Output - 3,451 MW
- Electrical Output - 1,100 MW
- Number of fuel assemblies - 157
- Fuel lattice - 17 ft x 17 ft
- Active Fuel Length - 12.0 ft
- Refueling Frequency - 18 month Refueling Interval

The reactor can use Uranium dioxide fuel rods.

***Decommissioning Cost***

After a nuclear energy center is closed and removed from service, it must be decommissioned. Decommissioning includes removal and disposal of radioactive components and materials at the nuclear energy center. The U.S. Nuclear Regulatory Commission (NRC) requires licensees to put aside funds for the eventual decommissioning throughout the energy center's operating life.

The reductions in building volumes, number of buildings, and number of components have a direct effect on the decommissioning costs of the AP1000 units. The AP1000 has 40% less building volume, 80% less piping, 50% fewer valves, and 85% less cable than a typical Generation II plant. Based upon the substantial reduction in volume of

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

material to be disposed of, decommissioning costs are likely less than existing nuclear facilities in the U.S. Based on licensing documents submitted to the NRC, over $400 million dollar decommissioning estimate (2007 dollars) was reported as part of the twin unit AP1000 project under construction at the Vogtle Site in Georgia. These estimates were reviewed and approved by the NRC.

Annual decommissioning fund contributions were estimated using the same inflation and fund return assumptions as in Ameren Missouri's 2011 Triennial Update filing for Callaway Energy Center.

### *Scheduled Outage*

The refueling cycle requirements control the scheduled routine and maintenance outages for nuclear units. Current enrichment limits of 5 percent prevent fuel cycle lengths longer than 24 months. Ameren Missouri assumed an 18 month refueling schedule; scheduled maintenance would occur in a 24 day period (3.43 weeks) every 18 months.

### *Forced Outage Rate and Availability*

Based on an expected forced outage rate of 2.0% and scheduled maintenance of 24 days every 18 months, annual availability is estimated to be approximately 94%.

### *Waste Generation*

Based on the South Carolina Electric & Gas Combined License (COL) Application for Summer 2&3, Westinghouse estimates that one AP1000 would generate approximately 5,760 cubic feet of low-level radioactive waste annually. Following volume reduction and compaction, the estimated low-level radioactive waste disposal volume is 1,960 cubic feet per year for each new unit.

### *Water Impacts*

Consumptive use of water is primarily attributable to evaporation losses from cooling water systems, blowdown, and cooling tower drift. The AP1000 will utilize two natural-draft cooling towers with evaporative losses of approximately 14,550 gallons per minute (gpm). Blowdown from the new cooling towers will be approximately 4,850 gpm each. The unit will consume a total of approximately 19,413 gpm including estimated cooling tower drift (12.5 gpm).

In comparison to average annual flow of the Missouri River over 50 years, such losses are estimated to require less than 0.1 percent of river flow. The water resources so committed for plant operation will have no material effect on other users downstream from the plant.

## 6.2.2 SMR Characterization

### *Design Parameters*

Key Westinghouse SMR design parameters include the following:

- Design life - 60 years
- Thermal Output - 800 MW
- Electrical Output - >225 MW
- Number of fuel assemblies - 89
- Fuel lattice - Partial-height of the 17 x 17 fuel assembly used in the AP1000 Reactor
- Active Fuel Length - 8.0 ft
- Refueling Frequency - 24 month Refueling Interval

The reactor can use Uranium enriched (U-235) in the fissile isotope up to 5%.

### *Decommissioning Cost*

The decommissioning cost for a SMR unit was estimated by scaling the decommissioning cost estimate for AP1000 by the ratio of net capacity of the two technologies, which resulted in an estimated cost of $100 Million. This is a conservative methodology as the reductions in plant size, number of buildings, and number of components is far greater in the AP1000 to Westinghouse SMR. The Westinghouse SMR is approximately 1/4 the power level of an AP1000 but the comparative size of containment building is 1/25.

Annual decommissioning fund contributions were estimated using the same inflation and fund return assumptions as in Ameren Missouri's 2011 Triennial Update filing for Callaway Energy Center.

### *Scheduled Outage*

Ameren Missouri has assumed a 24 month refueling schedule; scheduled maintenance would occur in an 8 day period every 24 months.

### *Forced Outage Rate and Availability*

Based on an expected forced outage rate of 2.0% and scheduled maintenance of 8 days every 24 months, annual availability is estimated to be 95.9%.

### *Waste Generation*

The estimated SMR low-level radioactive waste disposal volume is 394 cubic feet (11 $m^3$), which was determined by scaling the AP1000 estimates for a single 225 MW SMR unit based on relative capacity.

### *Water Impacts*

Consumptive use of water is primarily attributable to evaporation losses from cooling water systems, blowdown, and cooling tower drift. The estimated SMR water impacts will be approximately 3,910 gpm, again determined by scaling the AP1000 estimates for a single 225 MW SMR unit.

In comparison to average annual flow of the Missouri River over 50 years, such losses are estimated to require less than 0.1 percent of river flow. The water resources so committed for plant operation will have no material effect on other users downstream from the plant.

## 6.3 Supporting Tables

### Table 6B.12 Coal Options – Capacity and Performance[13]

| 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 | USCPC | 860 | 174 | 686 | 12,200 | 852 | 173 | 679 | 12,300 | 85% | 8% |
| CCC - Greenfield-Amine-Based Post Combustion | Coal | Baseload | Sub-CFB | 602 | 145 | 457 | 13,200 | 598 | 145 | 453 | 13,300 | 85% | 11% |
| 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% |
| 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% |

[13] 4 CSR 240-22.040(1)

## Table 6B.13 Gas Options – Capacity and Performance[14]

| 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% |
| Greenfield - 2-on-1 501F | Gas | Baseload | CCCT | 644 | 15.0 | 629 | 6,860 | 617 | 17.2 | 600 | 7,230 | 45% | 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% |
| 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% |
| 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% |

[14] 4 CSR 240-22.040(1)

## Table 6B.14 Coal Options – Cost Estimates[15]

| Resource Option | Fuel Type | Operations Mode | Technology Description | 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 | 3,293,841 | 4,851 | 3,702,277 | 5,453 | 23,048 | 33.9 | 31,982 | 6.52 | 14.90 | 2.47 | 12.4% | 22% | 34% |
| CCC - Greenfield-Amine-Based Post Combustion | Coal | Baseload | Sub-CFB | 2,760,202 | 5,030 | 3,444,300 | 7,000 | 22,980 | 50.7 | 40,713 | 12.10 | 18.90 | 2.47 | 12.5% | 23% | 35% |
| CCC - Greenfield-IGCC Pre Combustion | Coal | Baseload | IGCC | 2,348,878 | 4,763 | 3,406,630 | 6,906 | 24,334 | 49.4 | 39,641 | 11.47 | 18.52 | 2.47 | 24% | 21% | 45% |
| CCC - Greenfield - Oxyfuel Coal | Coal | Baseload | USCPC | 3,139,053 | 5,066 | 4,255,366 | 6,863 | 25,576 | 41.2 | 46,143 | 9.96 | 15.59 | 2.47 | 13.8% | 22% | 36% |
| Greenfield - Single Unit | Coal | Baseload | IGCC | 1,807,662 | 3,215 | 2,689,952 | 4,784 | 19,831 | 35.3 | 26,005 | 6.60 | 11.64 | 2.47 | 30% | 19% | 49% |
| Greenfield - Single Unit | Coal | Baseload | SC-CFB | 1,721,067 | 2,868 | 2,586,363 | 4,308 | 19,158 | 31.9 | 17,864 | 4.25 | 8.80 | 2.47 | 30% | 20% | 50% |
| Greenfield - Single Unit | Coal | Baseload | Sub-CFB | 1,623,648 | 2,706 | 2,277,654 | 3,799 | 18,964 | 31.6 | 18,497 | 4.13 | 8.39 | 2.47 | 20% | 20% | 40% |
| Greenfield - Single Unit | Coal | Baseload | USCPC | 2,084,764 | 2,316 | 2,834,606 | 3,150 | 18,878 | 21.0 | 19,828 | 3.05 | 5.65 | 2.47 | 20% | 20% | 40% |

[15] 4 CSR 240-22.040(5)(B); 4 CSR 240-22.040(5)(C)

## Table 6B.15 Gas Options – Cost Estimates

| Resource Option | Fuel Type | Operations Mode | Technology Description | Full Load Net Plant Output, MW (95 F) | Full Load Net Plant Heat Rate HHV, Btu/kWh (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 | 8,900 | 1,417,988 | 2,890 | 1,749,752 | 3,572 | 10,404 | 21.2 | 30,342 | 8.31 | 11.17 | 3.87 | 7.5% | 16% | 23% |
| Greenfield - 2-on-1 501F | Gas | Baseload | CCCT | 600 | 7,230 | 703,581 | 1,173 | 755,677 | 1,259 | 6,689 | 11.1 | 14,268 | 3.19 | 4.69 | 3.87 | 12% | 12% | 24% |
| Greenfield - 2x1 Wartsila 20V34SG (Profile 1) | Gas | Intermediate | Recip | 17.8 | 8,100 | 34,746 | 1,959 | 48,060 | 2,706 | 683 | 38.4 | 153 | 8.26 | 45.22 | 3.87 | 26% | 12% | 38% |
| Greenfield - Molten Carbonate | Gas | Intermediate | Fuel Cell | 100 | 8,450 | 541,216 | 5,412 | 678,038 | 6,778 | 0 | 0.0 | 28,209 | 37.89 | 37.89 | 3.87 | 5% | 20% | 25% |
| Greenfield - Two 501Fs (10% CF) | Gas | Peaking | SCCT | 346 | 10,700 | 264,113 | 758 | 326,570 | 942 | 2,583 | 7.5 | 4,212 | 13.86 | 22.40 | 3.87 | 15% | 9% | 24% |
| Greenfield - Two 501Fs (5% CF) | Gas | Peaking | SCCT | 352 | 10,530 | 241,382 | 686 | 269,674 | 766 | 2,625 | 7.5 | 2,538 | 16.45 | 33.49 | 3.87 | 16% | 9% | 25% |
| Mexico - One LM6000 Sprint (10% CF) | Gas | Peaking | SCCT | 39.3 | 9,780 | 49,142 | 1,245 | 64,729 | 1,645 | 1,173 | 29.9 | 242 | 7.04 | 41.08 | 3.87 | 23% | 9% | 32% |
| Mexico - One LM6000 Sprint (5% CF) | Gas | Peaking | SCCT | 39.7 | 9,690 | 41,674 | 1,050 | 56,070 | 1,407 | 1,184 | 29.9 | 109 | 6.30 | 74.40 | 3.87 | 26% | 9% | 35% |
| Raccoon Creek - One 7EA (5% CF) | Gas | Peaking | SCCT | 73.9 | 12,170 | 65,379 | 888 | 84,105 | 1,137 | 1,205 | 16.3 | 610 | 18.83 | 56.07 | 3.87 | 20% | 9% | 29% |
| Raccoon Creek -One 7EA (10% CF) | Gas | Peaking | SCCT | 73.2 | 12,280 | 74,904 | 1,028 | 95,579 | 1,310 | 1,194 | 16.3 | 1,058 | 16.45 | 35.09 | 3.87 | 19% | 9% | 28% |
| Greenfield - 7EA (Profile 2) | Gas | Intermediate | Cheng | 96 | 9,700 | 87,677 | 920 | 113,439 | 1,191 | 1,558 | 16.3 | 2,088 | 11.69 | 20.39 | 3.87 | 17% | 12% | 29% |
| Greenfield - Twelve Wartsila Recip Engines | Gas | Peaking | Recip | 99.0 | 8,740 | 150,458 | 1,515 | 186,070 | 1,883 | 2,803 | 28.4 | 384 | 8.85 | 73.51 | 3.87 | 14% | 10% | 24% |

## Table 6B.16 Coal Options – Commercial Status, Construction Duration and Environmental Characteristics[16]

| Resource Option | Fuel Type | Operations Mode | Technology Description | Fuel Flexibility | Technology Maturity | Permitting & Development, months | NTP to COD, months | Assumed Annual Capacity Factor, percentage | Forced Outage Rate, percentage (%) | 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 | Yes | Developing | 24 to 36 | 64 | 85% | 8% | 0.05 | 0.06 | 21.2 | 0.12 | 0.012 | 90% | 4,150 to 7,700 |
| CCC - Greenfield-Amine-Based Post Combustion | Coal | Baseload | Sub-CFB | Yes | Developing | 24 to 36 | 66 | 85% | 11% | 0.08 | 0.08 | 21.2 | 0.13 | 0.012 | 90% | 3,100 to 5,750 |
| CCC - Greenfield-IGCC Pre Combustion | Coal | Baseload | IGCC | Limited | Developing | 24 to 36 | 62 | 80% | 13% | 0.01 | 0.03 | 21.2 | 0.03 | 0.011 | 90% | 1,650 to 3,100 |
| CCC - Greenfield - Oxyfuel Coal | Coal | Baseload | USCPC | Yes | Developing | 24 to 36 | 64 | 85% | 8% | 0.005 | 0.006 | 21.2 | 0.012 | 0.0012 | 90% | 3,200 to 5,950 |
| Greenfield - Single Unit | Coal | Baseload | IGCC | Limited | Developing | 24 to 36 | 56 | 80% | 13% | 0.01 | 0.03 | 212 | 0.03 | 0.011 | 90% | 1,500 to 2,800 |
| Greenfield - Single Unit | Coal | Baseload | SC-CFB | Yes | Developing | 24 to 36 | 60 | 80% | 11% | 0.08 | 0.08 | 212 | 0.13 | 0.012 | 90% | 2,400 to 4,450 |
| Greenfield - Single Unit | Coal | Baseload | Sub-CFB | Yes | Mature | 24 to 36 | 60 | 85% | 11% | 0.08 | 0.08 | 212 | 0.13 | 0.012 | 90% | 2,400 to 4,450 |
| Greenfield - Single Unit | Coal | Baseload | USCPC | Yes | Mature | 24 to 36 | 58 | 85% | 8% | 0.05 | 0.06 | 212 | 0.12 | 0.012 | 90% | 3,200 to 5,950 |

[16] 4 CSR 240-22.040(1)

## Table 6B.17 Gas Options – Commercial Status, Construction Duration and Environmental Characteristics[17]

| 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 |
| 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 |
| 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 |
| 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 |

[17] 4 CSR 240-22.040(1)

## Table 6B.18 Coal Options – Economic Parameters and LCOE[18]

| 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 | LCOE w 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 | 2.0% | 2.0% | 4.3% | 6.46% | 10.20% | N/A | N/A | 16.28 | 0.00 | 16.28 | 0.06 | 16.3 |
| CCC - Greenfield-Amine-Based Post Combustion | Coal | Baseload | Sub-CFB | 453 | 40 | 2.0% | 2.0% | 4.3% | 6.46% | 10.20% | N/A | N/A | 21.52 | 0.00 | 21.52 | 0.06 | 21.6 |
| CCC - Greenfield-IGCC Pre Combustion | Coal | Baseload | IGCC | 493 | 30 | 2.0% | 2.0% | 4.3% | 6.46% | 10.89% | N/A | N/A | 20.58 | 0.00 | 20.58 | 0.04 | 20.6 |
| CCC - Greenfield - Oxyfuel Coal | Coal | Baseload | USCPC | 620 | 40 | 2.0% | 2.0% | 4.3% | 6.46% | 10.20% | N/A | N/A | 19.80 | 0.00 | 19.80 | 0.06 | 19.9 |
| CCC - Meramec - Oxyfuel Coal | Coal | Baseload | USCPC | 620 | 40 | 2.0% | 2.0% | 4.3% | 6.56% | 10.34% | N/A | N/A | 19.10 | 0.00 | 19.10 | 0.06 | 19.2 |
| Greenfield - Single Unit | Coal | Baseload | IGCC | 562 | 30 | 2.0% | 2.0% | 4.3% | 6.46% | 10.89% | N/A | N/A | 13.07 | 0.00 | 13.07 | 0.34 | 13.4 |
| Greenfield - Single Unit | Coal | Baseload | SC-CFB | 600 | 40 | 2.0% | 2.0% | 4.3% | 6.46% | 10.20% | N/A | N/A | 11.93 | 0.00 | 11.93 | 0.45 | 12.4 |
| Greenfield - Single Unit | Coal | Baseload | Sub-CFB | 600 | 40 | 2.0% | 2.0% | 4.3% | 6.46% | 10.20% | N/A | N/A | 10.73 | 0.00 | 10.73 | 0.47 | 11.2 |
| Greenfield - Single Unit | Coal | Baseload | USCPC | 900 | 40 | 2.0% | 2.0% | 4.3% | 6.46% | 10.20% | N/A | N/A | 9.10 | 0.00 | 9.10 | 0.44 | 9.5 |

18 4 CSR 240-22.040(2)(C)1

## Table 6B.19 Gas Options – Economic Parameters and LCOE[19]

| 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 | 2.0% | 2.0% | 2.7% | 6.56% | 11.01% | N/A | N/A | 14.9 | 0.0002 | 0.02 | 15.0 |
| Greenfield - 2-on-1 501F | Gas | Baseload | CCCT | 600 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 11.01% | N/A | N/A | 9.31 | 0.0002 | 0.15 | 9.5 |
| Greenfield - 2x1 Wartsila 20V34SG (Profile 1) | Gas | Intermediate | Recip | 17.8 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 41.2 | 0.0006 | 0.17 | 41.4 |
| Greenfield - Molten Carbonate | Gas | Intermediate | Fuel Cell | 100 | 20 | 2.0% | 2.0% | 2.7% | 6.56% | 12.34% | N/A | N/A | 23.59 | 0.0001 | 0.20 | 23.8 |
| Greenfield - Two 501Fs (10% CF) | Gas | Peaking | SCCT | 346 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 22.2 | 0.0003 | 0.22 | 22.4 |
| Greenfield - Two 501Fs (5% CF) | Gas | Peaking | SCCT | 352 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 29.11 | 0.0007 | 0.17 | 29.3 |
| Mexico - One LM6000 Sprint (10% CF) | Gas | Peaking | SCCT | 39.3 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 33.1 | 0.0004 | 0.20 | 33.3 |
| Mexico - One LM6000 Sprint (5% CF) | Gas | Peaking | SCCT | 39.7 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 52.63 | 0.0013 | 0.20 | 52.8 |
| Raccoon Creek - One 7EA (5% CF) | Gas | Peaking | SCCT | 73.9 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 44.8 | 0.0010 | 0.25 | 45.0 |
| Raccoon Creek -One 7EA (10% CF) | Gas | Peaking | SCCT | 73.2 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 29.53 | 0.0003 | 0.25 | 29.8 |
| Greenfield - 7EA (Profile 2) | Gas | Intermediate | Cheng | 96 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 16.5 | 0.0004 | 0.20 | 16.7 |
| Greenfield - Twelve Wartsila Recip. Engines | Gas | Peaking | Recip | 99.0 | 30 | 2.0% | 2.0% | 2.7% | 6.56% | 10.67% | N/A | N/A | 64.62 | 0.0067 | 0.18 | 64.8 |

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

## Table 6B.20a Coal Options – Scoring Results[20]

| 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 | 42 | 42 | 44 | 100 | **16.8** | **16.8** | **17.2** | 85 | 100 | **18.2** | 25 | 25 | 50 | **4.5** |
| CCC - Greenfield-Amine-Based Post Combustion | Coal | Baseload | Sub-CFB | 453 | 0 | 0 | 0 | 100 | **3.5** | **3.5** | **3.5** | 85 | 100 | **18.2** | 25 | 25 | 50 | **4.5** |
| CCC - Greenfield-IGCC Pre Combustion | Coal | Baseload | IGCC | 493 | 8 | 8 | 8 | 100 | **5.9** | **5.9** | **6.0** | 85 | 100 | **18.2** | 25 | 25 | 50 | **4.5** |
| CCC - Greenfield - Oxyfuel Coal | Coal | Baseload | USCPC | 620 | 14 | 14 | 14 | 100 | **7.8** | **7.9** | **8.0** | 85 | 100 | **18.2** | 25 | 25 | 50 | **4.5** |
| Greenfield - Single Unit | Coal | Baseload | IGCC | 562 | 68 | 68 | 68 | 100 | **24.9** | **24.9** | **24.9** | 85 | 75 | **16.2** | 50 | 25 | 50 | **6.75** |
| Greenfield - Single Unit | Coal | Baseload | SC-CFB | 600 | 77 | 77 | 76 | 100 | **27.8** | **27.8** | **27.6** | 85 | 75 | **16.2** | 50 | 25 | 50 | **6.75** |
| Greenfield - Single Unit | Coal | Baseload | Sub-CFB | 600 | 87 | 87 | 86 | 100 | **30.9** | **30.8** | **30.6** | 85 | 75 | **16.2** | 100 | 25 | 50 | **11.25** |
| Greenfield - Single Unit | Coal | Baseload | USCPC | 900 | 100 | 100 | 100 | 100 | **35.0** | **35.0** | **35.0** | 85 | 75 | **16.2** | 100 | 25 | 50 | **11.25** |

[20] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(C)1

## Table 6B.20b Coal Options – Scoring Results

| 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** | **55** | **55** | **55** |
| CCC - Greenfield-Amine-Based Post Combustion | Coal | Baseload | Sub-CFB | 453 | 25 | 0 | 25 | 100 | 50 | 25 | **6** | 100 | 25 | 25 | **9** | **42** | **42** | **42** |
| CCC - Greenfield-IGCC Pre Combustion | Coal | Baseload | IGCC | 493 | 25 | 7 | 25 | 75 | 50 | 25 | **6** | 50 | 25 | 25 | **6** | **40** | **40** | **40** |
| CCC - Greenfield - Oxyfuel Coal | Coal | Baseload | USCPC | 620 | 25 | 0 | 25 | 100 | 50 | 25 | **6** | 100 | 25 | 25 | **9** | **46** | **46** | **46** |
| Greenfield - Single Unit | Coal | Baseload | IGCC | 562 | 25 | 18 | 25 | 75 | 50 | 50 | **6** | 50 | 25 | 25 | **6** | **60** | **60** | **60** |
| Greenfield - Single Unit | Coal | Baseload | SC-CFB | 600 | 25 | 11 | 25 | 100 | 50 | 50 | **7** | 50 | 25 | 25 | **6** | **63** | **63** | **63** |
| Greenfield - Single Unit | Coal | Baseload | Sub-CFB | 600 | 25 | 11 | 25 | 100 | 50 | 75 | **8** | 100 | 50 | 25 | **10** | **76** | **76** | **76** |
| Greenfield - Single Unit | Coal | Baseload | USCPC | 900 | 25 | 14 | 25 | 100 | 50 | 75 | **8** | 100 | 50 | 25 | **10** | **80** | **80** | **80** |

## Table 6B.21a Gas Options – Scoring Results[21]

| 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 | 90 | 90 | 90 | 100 | **31.8** | **31.8** | **31.9** | 85 | 100 | **18.2** | 25 | 25 | 50 | **4.5** |
| Greenfield - 2-on-1 501F | Gas | Baseload | CCCT | 600 | 100 | 100 | 100 | 100 | **35.0** | **35.0** | **35.0** | 85 | 75 | **16.2** | 100 | 50 | 50 | **12** |
| Greenfield - 2x1 Wartsila 20V34SG (Profile 1) | Gas | Intermediate | Recip | 17.8 | 42 | 42 | 42 | 100 | **16.8** | **16.8** | **16.8** | 85 | 50 | **14.2** | 100 | 50 | 50 | **12** |
| Greenfield - Molten Carbonate | Gas | Intermediate | Fuel Cell | 100 | 74 | 74 | 74 | 100 | **26.9** | **26.9** | **26.8** | 85 | 75 | **16.2** | 50 | 100 | 100 | **10.5** |
| Greenfield - Two 501Fs (10% CF) | Gas | Peaking | SCCT | 346 | 77 | 77 | 77 | 100 | **27.7** | **27.7** | **27.6** | 85 | 75 | **16.2** | 100 | 100 | 50 | **13.5** |
| Greenfield - Two 501Fs (5% CF) | Gas | Peaking | SCCT | 352 | 64 | 64 | 64 | 100 | **23.7** | **23.7** | **23.7** | 85 | 25 | **12.2** | 100 | 100 | 50 | **13.5** |
| Mexico - One LM6000 Sprint (10% CF) | Gas | Peaking | SCCT | 39.3 | 57 | 57 | 57 | 100 | **21.4** | **21.4** | **21.4** | 85 | 75 | **16.2** | 100 | 100 | 50 | **13.5** |
| Mexico - One LM6000 Sprint (5% CF) | Gas | Peaking | SCCT | 39.7 | 22 | 22 | 22 | 100 | **10.3** | **10.3** | **10.3** | 85 | 25 | **12.2** | 100 | 100 | 50 | **13.5** |
| Raccoon Creek - One 7EA (5% CF) | Gas | Peaking | SCCT | 73.9 | 36 | 36 | 36 | 100 | **14.8** | **14.8** | **14.7** | 85 | 25 | **12.2** | 100 | 100 | 50 | **13.5** |
| Raccoon Creek -One 7EA (10% CF) | Gas | Peaking | SCCT | 73.2 | 63 | 63 | 63 | 100 | **23.5** | **23.5** | **23.4** | 85 | 75 | **16.2** | 100 | 100 | 50 | **13.5** |
| Greenfield - 7EA (Profile 2) | Gas | Intermediate | Cheng | 96 | 87 | 87 | 87 | 100 | **30.9** | **30.9** | **30.9** | 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** |

[21] 4 CSR 240-22.040(2)(A); 4 CSR 240-22.040(2)(B); 4 CSR 240-22.040(2)(C)1

## Table 6B.21b Gas Options – Scoring Results

| 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** | **70** | **70** | **70** |
| 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** | **62** | **62** | **62** |
| Greenfield - Molten Carbonate | Gas | Intermediate | Fuel Cell | 100 | 100 | 11 | 0 | 100 | 50 | 75 | **8** | 100 | 100 | 25 | **11** | **73** | **73** | **73** |
| Greenfield - Two 501Fs (10% CF) | Gas | Peaking | SCCT | 346 | 50 | 13 | 0 | 75 | 100 | 75 | **8** | 100 | 100 | 100 | **15** | **80** | **80** | **80** |
| Greenfield - Two 501Fs (5% CF) | Gas | Peaking | SCCT | 352 | 50 | 13 | 0 | 75 | 100 | 75 | **8** | 100 | 100 | 100 | **15** | **72** | **72** | **72** |
| Mexico - One LM6000 Sprint (10% CF) | Gas | Peaking | SCCT | 39.3 | 50 | 13 | 0 | 75 | 100 | 75 | **8** | 100 | 100 | 100 | **15** | **74** | **74** | **74** |
| Mexico - One LM6000 Sprint (5% CF) | Gas | Peaking | SCCT | 39.7 | 50 | 13 | 0 | 75 | 100 | 75 | **8** | 100 | 100 | 100 | **15** | **59** | **59** | **59** |
| Raccoon Creek - One 7EA (5% CF) | Gas | Peaking | SCCT | 73.9 | 50 | 13 | 0 | 75 | 100 | 75 | **8** | 100 | 100 | 100 | **15** | **63** | **63** | **63** |
| Raccoon Creek -One 7EA (10% CF) | Gas | Peaking | SCCT | 73.2 | 50 | 13 | 0 | 75 | 100 | 75 | **8** | 100 | 100 | 100 | **15** | **76** | **76** | **76** |
| Greenfield - 7EA (Profile 2) | Gas | Intermediate | Cheng | 96 | 50 | 75 | 0 | 75 | 100 | 75 | **9** | 100 | 50 | 50 | **11** | **74** | **74** | **74** |
| Greenfield - Twelve Wartsila Recip. Engines | Gas | Peaking | Recip | 99.0 | 50 | 0 | 0 | 100 | 100 | 75 | **8** | 100 | 100 | 100 | **15** | **52** | **52** | **52** |

## 6.4 Compliance References