THERMAL GENERATION ALTERNATIVES STUDY

Revision: 1

Platte River Power Authority

HDR Project No. 10161829

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Executive Summary

Platte River Power Authority (Platte River) retained HDR Engineering, Inc. (HDR) to perform engineering services to support evaluation of new generation development alternatives for Integrated Resource Planning (IRP). This generation resource development effort is an update to the 2017 study performed by HDR and provides current, updated technical data, costs and information for numerous generation options for use in Platte River's IRP activities.

Platte River Power Authority is a not-for-profit wholesale electricity generation and transmission provider for the owner communities of Estes Park, Fort Collins, Longmont and Loveland, Colorado. Platte River has a strategic directive to diversify and balance the generation supply portfolio including intermediate resources to improve the resource mix in support of renewable generation and a reduced carbon footprint.

The information provided in this study includes generation performance estimates, emissions data, capital cost estimates, operations and maintenance cost estimates and Aurora market model input for each of the potential generation alternatives identified and evaluated.

The natural gas configurations evaluated include the following:

- Alternative 1 – 6 unit Wartsila 18V50SG Simple Cycle Configuration
- Alternative 2 – 3 unit Wartsila 18V50SG Simple Cycle Configuration
- Alternative 3 – 2 unit GE LM6000 Simple Cycle Configuration
- Alternative 4 – 2x1 GE LM6000 Combined Cycle Configuration, Air Cooled
- Alternative 5 – 1 unit GE LMS100 Simple Cycle Configuration
- Alternative 6 – 1 unit GE7F.05 Simple Cycle Configuration
- Alternative 7 – 1x1 GE7F.05 Combined Cycle Configuration with Duct Firing, Air Cooled

Table ES-1 below provides a summary of the natural gas configuration options and associated performance, capital and operating costs. The performance is based on average day unfired conditions at a green field site in Colorado. The conceptual capital costs are based on 2019 dollars and includes an allocation for Owner's costs. Operations and maintenance costs are based on first year operating costs in 2019 dollars. Refer to Section 3 for a more detailed description of the basis and assumptions for the values below.

Table ES-1: Summary of Alternatives

Summary of Alternatives		Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6	Alternative 7
		6x0 18MW RICE (NG)	3x0 18MW RICE (NG)	2x0 50MW Aero (NG)	2x1 50MW Aero (NG)	1x0 100MW Aero (NG)	1x0 F-Class (NG)	1x1 F-Class (NG) DB
Gross Output	MW	112.902	56.451	83.688	110.826	81.353	196.856	281.916
Auxiliary Power	MW	2.146	1.090	1.014	3.039	2.289	2.421	7.195
Net Output	MW	110.756	55.361	82.673	107.787	79.064	194.435	274.722
Net Cycle Heat Rate, HHV	Btu/kWh	8,364	8,367	9,403	7,207	9,009	9,691	6,788
Net Cycle Efficiency	% HHV	41%	41%	36%	47%	38%	35%	50%
Capital Cost	$/kw net	1,252	1,389	1,184	1,748	1,421	715	1,322
EPC Costs	$/kw net	1,081	1,199	1,022	1,502	1,214	617	1,141
Owner Cost	$/kw net	171	190	162	246	207	98	181
First Year Operating Costs ($2019)								
Fixed O&M	$/kw-year	$ 5.96	$ 10.97	$ 9.32	$ 29.34	$ 8.59	$ 4.63	$ 12.38
Variable O&M	$/MWH	$ 4.40	$ 4.40	$ 5.34	$ 4.64	$ 5.64	$ 4.13	$ 4.59
Consumables	$/MWH	$ 1.01	$ 1.01	$ 0.76	$ 0.17	$ 0.15	$ 0.16	$ 0.15

A cost of generation or comparative lifecycle analysis is not included herein as these generation options will be evaluated and compared through the Aurora model analysis.

As this effort to develop new generation alternatives has been structured as a preliminary assessment of technical aspects, capital cost, and O&M for new generation additions, a number of subsequent activities or next steps may be pursued once the a generation technology is selected.

- Conduct a siting study to select preferred site for the project.
- An assessment of the electrical transmission system impacts and associated costs for any incremental generation at the particular site.
- An assessment of the natural gas supply system impacts and associated costs for any incremental generation at the particular site.
- Evaluation of the water supply and wastewater discharge capability at the site under consideration.

1. Introduction

Platte River Power Authority is evaluating options to diversify and balance their generation portfolio to support their strategic plan. The strategic plan identifies the need for intermediately dispatchable resources that can support ancillary service requirements and allow for integration of renewable generation. Platte River retained HDR Engineering, Inc. (HDR) to perform engineering services to support evaluation of new gas fired generation development options for their 2020 Integrated Resource Planning (IRP) process.

The purpose of this study is to characterize potential natural gas fired generation resources selected by the Platte River evaluation team in support of the IRP process. The information provided in this study includes generation performance estimates, emissions data, capital cost estimates, operations and maintenance cost estimates, and inputs to the Aurora electric market model for each of the potential generation options identified.

This report is organized as follows:

- Section 2 -- Background of the selection of potential new alternatives.
- Section 3 -- Basis and assumptions for the cost estimates.
- Section 4 -- Plant performance.
- Section 5 -- Fuel supply requirements.
- Section 6 -- Aurora model inputs.

2. Background

2.1 New Resource Alternatives

The new resource options evaluated herein can be characterized as peaking to intermediate gas fired dispatch resources and focus on dispatchable generation with improved heat rates. The generation options can provide fast startup, ramping and load following capability to support an increase in future renewable generation.

The gas fired resource options evaluated within this study are summarized in Table 2.1-1 below and include a few combined cycle configurations. These configurations use air cooled condensers for heat rejection.

Table 2.2-1: Summary of New Resource Alternatives

Alternative No.	Plant Configuration	Net Capacity Average Day (MW)	Net Plant Heat Rate Average Day (Btu/kWh)HHV	Proxy Technology
1	6 unit Wartsila 18V50SG Simple Cycle	110	8,364	18V50SG (NG)
2	3 unit Wartsila 18V50SG Simple Cycle	55	8,367	18V50SG (NG)
3	2 unit GE LM6000 Simple Cycle	83	9,403	GE LM6000 PF+ DLN (NG)
4	2x1 GE LM6000 Combined Cycle	108	7,207	GE LM6000 PF+ DLN (NG)
5	1 unit GE LMS100 Simple Cycle	79	9,009	GE LMS100PB Dry Intercooled DLN (NG)
6	1 unit GE7F.05 Simple Cycle	194	9,691	GE 7F.05 (NG)
7	1x1 GE7F.05 Combined Cycle Configuration with Duct Firing	274	6,788	GE 7F.05 (NG) DB

2.2 Resource Alternatives Description

The following section provides a general description of the various alternatives considered. Plant performance related information is discussed in Section 3.

2.2.1 Reciprocating Internal Combustion Engines

Reciprocating internal combustion engines (RICE or reciprocating engines) are commonly used in the automobile, marine, and power generation industries. Reciprocating engines are characterized by the type of combustion utilized and are either of the spark ignition (thermodynamic Otto cycle) or compression ignition (thermodynamic diesel cycle) type.

Reciprocating engines utilized in the power generation industry range from smaller units rated at nominally 500 kW to 1 MW (common for emergency /backup applications) up to 20 MW (single unit) based on current original equipment manufacturer (OEM) offerings. Major OEMs for RICE generators include Caterpillar, Wartsila, and MAN Turbo among others. While generally smaller in terms of per unit output capability as compared to combustion turbine generator (CTG) offerings, larger reciprocating engines can be characterized by slightly more attractive unit efficiencies in the 35 percent to 40 percent range (HHV basis). A typical reciprocating engine plant configuration consists of multiple engines operating in sync. The engines are capable of starting and ramping very quickly, and are able to follow load changes rapidly. Reciprocating engines are increasingly gaining popularity for these stated reasons in utility systems with increasing renewables penetration. Much like other combustion technologies, reciprocating engines will require the use of emission control technologies such as selective catalytic reduction (SCR) and oxidation catalysts.

Alternatives 1 & 2: The nominal capacity rating for Alternatives one and two are 100 MW and 50 MW respectively. For comparison both alternatives use performance from a nominal 18 MW rated RICE generator operation on natural gas. OEM information from the Wartsila 18V50SG was used as a proxy for these configurations.

Alternative One utilized six of these engines for average day plant capacity rating of 110 MW, and three engines were used in Alternative Two for average day plant capacity rating of 55 MW.

2.2.2 Aeroderivative Combustion Turbine Configurations

Aeroderivative CTG designs stem from the aircraft industry, and are generally operating with higher pressure ratios (and therefore requiring higher fuel gas pressure) and exhausting at lower temperatures as compared to frame technology, making them more attractive in terms of unit efficiency. Much like Frame CTG technology, ambient conditions, such as temperature, relative humidity, and elevation (barometric pressure) impact performance characteristics of CTGs since they are volumetric machines and varying ambient conditions impact air mass flow through the units, which impacts the power output of the turbine.

Aeroderivative CTG are often utilized in "peaking" applications due to their relatively lower overall installed capital costs and their ability to start quickly (typically less than 10 minutes) and respond to generating needs during periods of peak power demand. Their fast start and ramping capability are highly desirable in utility systems with increasing renewable energy resources with intermittent and variable energy production.

Alternative 3 & 4: The nominal capacity rating for Alternative three is 100 MW. The GE LM6000 has a maximum nominal 50 MW capacity per unit in simple cycle configuration at ISO conditions. At the specified site elevation conditions and the average day conditions the capacity reduces to approximately 43 MW(net) per unit. OEM information from GE LM6000 CTG was used as a proxy for these configurations.

Alternative 4 is a combined cycle 2x1 GE LM6000 CTG with an average day plant capacity rating of 111 MW(net) that uses air cooling for heat rejection.

Alternative 5: The nominal capacity rating for Alternative five is also 100 MW. This alternative used performance from a nominal 100MW Aeroderivative CTG operating on natural gas in a simple cycle configuration. OEM information from GE LMS100 CTG was used as a proxy.

This single unit configuration has an average day plant capacity rating of 79 MW.

2.2.3 Frame Combustion Turbine Configurations

Frame CTG design is one of the tried-and-tested technologies in the power generation industry with several decades of operating history in domestic and international markets. The technology is known for its rugged design and attractive installed capital costs and, typically possesses slightly lower efficiencies when compared to aeroderivative designs. While typically used in intermediate to base load mode, modern 'F' class CTG units have enhanced capability to offer fast starting and load following ability down to their emission compliance limit point.

Alternative 6: The nominal capacity rating for Alternative 6 is 240 MW. This alternative used performance from a nominal 250 MW GE 7F.05 CTG operating on natural gas in a simple cycle configuration. OEM information from GE CTG was used as a proxy.

This single unit configuration has an average day plant capacity rating of 197 MW.

Alternative 7: The nominal capacity rating for Alternative 7 is 300 MW. This alternative used performance from a nominal 250 MW GE 7F.05 CTG operating on natural gas in a combined cycle configuration with duct firing capability and fitted with an air-cooled condenser. OEM information from GE CTG was used as a proxy.

This single unit configuration has an average day plant capacity rating of 274 MW.

3. Basis of Assessment

This section provides the basis and assumptions used in developing the cycle performance estimates, project capital cost estimates, operations and maintenance estimates and other information developed for the various generation options.

3.1 Site Characteristics

The project site ambient conditions assumed for developing performance predictions in the evaluation are defined as follows:

Table 3.1-1. Site Ambient Design Conditions

Site Ambient Conditions	Summer	Average Day	Winter
Dry Bulb Temperature (F)	90.8	49.6	32.0
Wet Bulb Temperature (F)	60.5	38.8	25.4
Relative Humidity (%)	18.4	40	42

The site is assumed to be a greenfield location and to be generally level with an elevation of 5,680 ft above sea level.

3.2 Fuel Supply

All of the generation options considered in this study would utilize natural gas as fuel. For the purposes of this evaluation, it is assumed that there is adequate gas supply capacity with sufficient pressure to meet the demand of each generation alternative. A summary of the required natural gas flow and pressure requirements for each of the alternative is included in Section 5.0.

Table 3.2-1 represents the natural gas fuel analysis utilized for the natural gas fired simple and combined cycle combustion turbine installations as well as for the natural gas fired engine generator options.

Table 3.2-1. Natural Gas Fuel Analysis.

Fuel Analysis	Natural Gas	
Heating Values		
LHV (btu/lb)	19900	BTU/lb
HHV (btu/lb)	22,032	BTU/lb
Volumetric LHV	901	BTU/ft^3

Fuel Analysis	Natural Gas	
Volumetric HHV	997	BTU/ft^3
Analysis of Fuel (volume %)		
H2	0.36	%
O2	0.07	%
H2O	0.00	%
N2	3.61	%
CO	0.09	%
CO2	0.34	%
CH$	87.00	%
C2H6	8.46	%
C2H4	0.03	%
H2S	0.04	%
Total	100.00	%

3.3 Operations and Maintenance Cost Assumptions

Operating and maintenance (O&M) costs are broken into fixed and variable costs. These costs are further broken into combustion turbine / engine service contract agreement costs and balance of plant components where appropriate. All costs are presented in 2019 US dollars.

While these O&M costs vary from technology to technology, the fundamental breakdown between fixed and variable O&M costs can be summarized as follows:

> **Fixed O&M**: Fixed operations and maintenance costs take into account plant operating and maintenance staff as well as other fixed costs associated with facility operations such as building and site maintenance. Also included are fixed service contract costs for the combustion turbine generators /engines and routine contracted labor for maintenance on other major equipment. Insurances, and property taxes were not considered.
>
> **Variable O&M**: Variable costs include costs for delivery and disposal of all materials utilized within the power generation process, including ammonia, water, water treatment, oil and other consumables. Variable costs also include variable service contract costs for the combustion turbine generators / engines, major equipment maintenance, and BOP equipment maintenance. Maintenance costs that may be incurred periodically over the life of the plant (such as catalyst replacement costs) have been levelized to reflect an annual cost. Emissions allowance costs are not considered or included in the variable O&M.

Fixed costs utilized in the analysis, are defined below in Table 3.3-1.

Table 3.3-1. Fixed O&M Costs.

Fixed Cost	First Year Price (2019$)	
Annual Cost for Salaried Staff	$140,000	
Annual Cost for Hourly Staff	$100,000	
Insurance	0%	of EPC Project Cost
Property Tax	0%	of Net Book Value
Annual Site and Building Maintenance	$150,000	

Plant staffing assumptions have been assumed as indicated in Table 3.3-2 for each option.

Table 3.3-2. Plant Staffing.

Alternative	Description	Incremental Salaried Staff	Incremental Hourly Staff
1	6x0 18V50SG (NG)	1	2
2	3x0 18V50SG (NG)	1	2
3	2x0 LM6000 (NG)	1	2
4	2x1 LM6000 (NG)	6	18
5	1x0 LMS100 (NG)	1	2
6	1x0 7F.05 (NG)	1	2
7	1x1 7F.05 (NG) DB	6	18

Commodity costs required for determining variable maintenance costs are summarized in Table 3.3-3.

Table 3.3-3. Variable O&M Costs.

Consumable	First Year Unit Price (2019$)
Ammonia	$166.52 / Ton (as 19% NH_3)
Engine Lube Oil	$7.00 / gal
Makeup Water	$1.50 / kgal
Demin Water	$3.50 / kgal

Waste Water Treatment	$1.00 / kgal
Cycle Chemical Feed	$0.015 / Ton steam produced

Maintenance contract costs for the combustion turbines and engines have been estimated based on typical service agreement contracts for the respective technology or based on similar project experience.

O&M costs within this report are presented on the basis that the facilities under consideration will be intermediate dispatch for combined cycle applications, and peaking to intermediate dispatch for the reciprocating engines and simple cycle options. Expected capacity factors for each technology utilized as a basis of the calculation of the O&M costs are summarized as follows:

- Intermediate Dispatch (combined cycle) Options:
    - 4,222 hours annually
    - 250 starts annually
- Peaking Dispatch (simple cycle and RICE) Options:
    - 775 hours annually
    - 100 starts annually

Operating and maintenance costs for the options are depicted in Table 3.3-4 and are presented in 2019 U.S. dollars. The costs are broken down into fixed O&M and variable O&M. Additional detail regarding the buildup of the O&M is included in Appendix 3.

Table 3.3-4. Operations and Maintenance Cost Summary

Operating Costs, 2019 $		Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6	Alternative 7
		6x0 18V50SG (NG)	3x0 18V50SG (NG)	2x0 LM6000 (NG)	2x1 LM6000 (NG)	1x0 LMS100 (NG)	1x0 7F.05 (NG)	1x1 7F.05 (NG) DB
Average								
Fixed O&M	$/kW-yr	5.96	10.97	9.32	29.34	8.59	4.63	12.38
Variable O&M	$/MWH	5.42	5.42	6.10	4.81	5.80	4.29	4.74

3.4 Capital Cost Basis

AACE Class 4/5 level conceptual total project capital cost estimates have been developed based on an overnight EPC project cost basis for 2019. These costs have assumed that new generation alternatives will be installed at a green field site in the State of Colorado. Adjustments for Colorado wage rates, productivity factors, and representative site conditions have been made.

Capital cost information includes project direct costs, construction indirects, and project indirects. Project direct costs include equipment costs; commodities such as piping, valves, insulation, electrical wiring, etc.; and construction labor. Construction indirects include equipment, field staff, permits, testing, temporary facilities, temporary utilities, and other expenses typical for such a project. Project indirects include design engineering and project management costs.

Owner's costs have also been estimated and include project management /administration, engineering and execution support during construction, Owner contingency, insurances, project development costs, and other costs typically incurred during project development and execution. Initiation fees as applicable for service contracts on the CTG's and engines are also included in the Owner's costs.

Costs not included in the capital cost estimates are listed below.

- Land procurement
- Financing fees
- Escalation
- Sales Tax
- Electrical transmission system upgrade costs
- Electrical transmission interconnection and transmission line costs
- Natural gas offsite supply line

The basis of the capital costs are the same for each option and therefore are appropriate for comparative purposes, but not for assessing the overall project cost as further project definition would be required for this purpose. All project $/kW values presented within this report are computed based upon dividing the project costs by the net plant capacity under average operating conditions.

It must be noted that all costs presented herein are based on current day cost expectations and actual project data and quotations where available. They are intended to reflect the current status of the industry with respect to recent material and labor escalation; however, due to the volatility of the power generation marketplace, actual project costs should be expected to vary.

The sections below provide a high level summary of the project scope of supply used as the basis for the cost estimate. The EPC costs represent power plant inside the fence costs only and therefore are inclusive of the gas line into the plant from the site boundary, water supply and discharge at the plant boundary, and electrical up to and including the switchyard. Typical power generation industry equipment redundancy is included for high plant reliability.

Table 3.4-1 provides estimated project costs for each option. Total project costs represent the estimated installed cost in overnight, 2019 dollars. More detailed cost estimate summary sheets are included in Appendix 2.

Table 3.4-1. Project Estimated Cost Summary.

Project Costs (2019 US $)		Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6	Alternative 7
		6x0 18V50SG (NG)	3x0 18V50SG (NG)	2x0 LM6000 (NG)	2x1 LM6000 (NG)	1x0 LMS100 (NG)	1x0 7F.05 (NG)	1x1 7F.05 (NG) DB
Total Plant Cost	$1000	$ 138,639	$ 76,917	$ 97,874	$ 188,418	$ 112,344	$ 139,042	$ 363,199
Total Plant Cost	$/kW	$ 1,252	$ 1,389	$ 1,184	$ 1,748	$ 1,421	$ 715	$ 1,322
EPC Plant Cost	$1000	$ 119,659	$ 66,387	$ 84,475	$ 161,853	$ 95,980	$ 120,007	$ 313,477
Owner's Cost	$1000	$ 18,980	$ 10,530	$ 13,399	$ 26,565	$ 16,364	$ 19,035	$ 49,722

3.4.1 Project Scope for Cost Estimates

The following is a brief description of the basis of costs estimated in this study.

RECIPROCATING ENGINE PLANT ALTERNATIVES

Wartsila 18V50SG reciprocating engines are considered for the development of proxy performance and costs for this alternative, with six units required to achieve a nominal plant output of 100 MW (each unit rated at 18+ MW at ISO conditions). OEMs such as MAN Turbo, and others could also supply engines in this size range.

The following was considered for Alternative 1 a six unit 18V50SG plant, and Alternative 2 a three unit 18V50SG reciprocating engine plant capital cost estimate:

- Indoor installation
- Natural gas fuel as the primary fuel with no alternative fuel
- Dry, fin fan radiators serving as the engine heat rejection system
- SCR and oxidation catalysts to reduce NO_x, CO and VOC emissions,
- 19 percent aqueous ammonia for the SCR system
- Balance of plant systems and equipment including switchyard and GSU transformer

CTG ALTERNATIVES

Aeroderivative and Frame CTG technologies were both considered in simple and combined cycle configurations in this study. OEM data from GE was used as proxy for these configurations. Other OEMs such as Siemens and Mitsubishi Hitachi Power Systems (MHPS) could also supply similar equipment.

The following scope was considered for the simple cycle CTG options (Alternative 3 2x0 GE LM6000, Alternative 5 1x0 LMS100, and Alternative 6 1x0 GE 7F.05) plants:

- Outdoor installation of the CTG.
- Natural gas as the primary fuel with no alternative fuel.
- SCR to reduce NOx emissions and oxidation catalysts to reduce CO and VOC emissions.
- 19 percent aqueous ammonia for the SCR system.
- Balance of plant systems and equipment including switchyard and GSU transformer.
- Alternative 3: GE LM6000PF+ CTG technology with inlet air evaporative cooling (90% effective) utilized for ambient temperatures above 59°F and dry low-NOx (DLN) combustion technology. SPRINT technology was not included, but could be considered for additional power augmentation depending on water availability at the selected site.

The combined cycle plant configuration is more complex than the simple cycle options with systems associated with the bottoming cycle and heat rejection. The scope for supply of the CTG essentially is the same as show above for the simple cycle options. The following was considered for the combined cycle Alternative 4-2x1 GE LM6000, and Alternative 7-1x1 GE 7F.05 plants:

- Outdoor installation of the CTGs and HRSGs.
- Indoor installation of the STG.
- Natural gas as the primary fuel with no alternative fuel.
- Alternative 4:
    - GE LM6000PF+ CTG technology with inlet air evaporative cooling (90% effective) utilized for ambient temperatures above 59°F and dry low-NO_x (DLN) combustion technology. SPRINT technology was not included, but could be considered for additional power augmentation depending on water availability at the selected site.
    - Non-reheat, sliding pressure, fully condensing STG design.
    - Main steam throttle conditions of 900 psig and 700°F.
    - Horizontal, two pressure HRSGs.

- Alternative 7:
    - GE 7F.05 Series CTG technology with inlet air evaporative cooling (90% effective) utilized for ambient temperatures above 59°F and dry low-NO_x (DLN) combustion technology.
    - Reheat, sliding pressure, fully condensing STG design.
    - Horizontal, triple pressure HRSGs with fuel gas performance heating supplied from the intermediate pressure (IP) economizer. HRSG equipped with duct firing capability.

  - Main steam throttle conditions of 1,800 psig and 1,000°F and a reheat temperature of 1,000°F.
- Demineralized water treatment system with associated water storage tanks and forwarding pumps.
- Air cooled condenser for the dry cooled option.
- SCR to reduce NO_x emissions and oxidation catalyst to reduce CO and VOC emissions.
- 19 percent aqueous ammonia for the SCR system.
- Balance of plant systems and equipment including switchyard and GSU transformer.

Note that this study only considers electrical scope up to and including the switchyard for each of the alternatives. HDR notes that potential impacts to the existing electrical grid could be significant and the associated upgrade costs could be substantial. It is recommended that an electrical transmission system impact analysis be considered as part of downstream evaluation efforts. While the cost estimated in this report can be used for relative comparison, the additional cost of electrical interconnection will need to be considered for a broader evaluation of total project costs.

Costs presented herein are based on current day cost expectations, results of actual projects, and equipment budgetary quotations, where available. The estimates presented here are conceptual in nature, are for comparative and resource planning purposes only, and are not to be used for budget planning. Any opinions of probable project cost or probable construction cost provided by HDR are made on the basis of information available to HDR and prior experience. Since HDR has no control over the cost of labor, materials, equipment or services furnished by others, contractor's means and methods, or future market conditions, HDR does not warrant that proposals, bids, or actual project costs will not vary from the costs provided herein.

3.5 Project Schedule

Estimated project schedule durations for each option from EPC contractor notice to proceed (NTP) to the commercial operating date (COD) are summarized in the table below.

Table 3.5-1 Conceptual Project Schedule Duration

Alternative	Description	Schedule Duration (Months) EPC NTP to COD
1	6x0 18V50SG (NG)	~21 to 23
2	3x0 18V50SG (NG)	~21 to 23

3	2x0 LM6000 (NG)	~21 to 23
4	2x1 LM6000 (NG)	~32 to 34
5	1x0 LMS100 (NG)	~21 to 23
6	1x0 7F.05 (NG)	~21 to 23
7	1x1 7F.05 (NG) DB	~34 to 36

Note that the durations summarized above are conceptual in nature and that development activities such as EPC request for proposal development, securing bids, bid evaluation, contract negotiation, or allocations for permitting and regulatory approvals are not included.

4. Plant Performance

4.1 Performance Estimates

Overall new and clean net plant output, heat rates, and cycle conditions have been developed for each generation option. This data is depicted for each of the natural gas combustion turbine technologies and configurations in Tables 4.1-1 through 4.1-13 below. Performance has been developed at the following operating points at summer day, average day, and winter day conditions:

- 100% CTG/engine load with duct firing (if applicable)
- 100% CTG/engine load, no duct firing (if applicable)
- 75% CTG/engine load
- Minimum emissions compliance load (MECL) for the CTG/engine

Average output and thermal degradation for simple cycle plants are generally expected to be 3.8 and 2.3 percent, respectively, over the life of the plant based on combustion turbine supplier degradation curves. Average output and thermal degradation for a combined cycle plant are expected to be 3.0 and 1.78 percent, respectively, over the life of the plant based on combustion turbine, HRSG, and steam turbine degradation curves or data as well as balance of plant degradation.

For reciprocating engines, generating capacity is proportional to the mean effective pressure developed within the cylinders. Over time, the mass of combustion air can be reduced somewhat from phenomenon such as loss of compression within the cylinders and/or loss of turbocharger capacity due to fouling. This results in a lower effective pressure at the end of the compression cycle. MEP can be maintained up to a point by adding additional heat input. In general, reciprocating engines are designed with excess combustion air in order to completely combust the fuel during the relatively short combustion period available during each cycle. As a result, degradation of capacity is not expected between outages. Degradation of heat rate due to the increased fuel requirement to maintain MEP is a more salient concern. This heat rate degradation is fully recoverable once the underlying issue is addressed (cleaning of intercoolers, engine or turbo overhaul, etc.).

Table 4.1-1. Summer Full Load

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	106.011	2.02%	103.871	8,475
2	3x0 18V50SG	53.006	2.05%	51.919	8,478
3	2x0 LM6000	79.056	1.28%	78.046	9,555
4	2x1 LM6000	104.323	3.32%	100.863	7,388
5	1x0 LMS100	76.600	2.98%	74.314	9,143
6	1x0 7F.05	192.164	1.26%	189.747	9,773
7	1x1 7F.05 DB	276.017	2.59%	268.859	6,825
	1x1 7F.05 (NG) DB ON	292.263	2.53%	284.858	6,960

Table 4.1-2. Summer Part Load.

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	53.006	2.51%	51.678	8,518
2	3x0 18V50SG	35.337	2.31%	34.521	8,501
3	2x0 LM6000	32.704	1.87%	32.091	10,173
4	2x1 LM6000	44.491	5.79%	41.916	7,782
5	1x0 LMS100	52.979	4.18%	50.763	10,131
6	1x0 7F.05	137.010	1.73%	134.640	10,724
7	1x1 7F.05 DB	208.311	3.19%	201.673	7,083

Table 4.1-3. Summer MECL.

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	9.408	8.29%	8.629	9,844
2	3x0 18V50SG	9.408	5.72%	8.870	9,576
3	2x0 LM6000	16.503	3.63%	15.904	13,948
4	2x1 LM6000	25.451	9.63%	23.000	9,639
5	1x0 LMS100	35.448	6.11%	33.283	11,754
6	1x0 7F.05	92.134	2.53%	89.802	12,366
7	1x1 7F.05 DB	151.602	4.09%	145.397	7,558

Table 4.1-4. Average Day, Full Load

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	112.902	1.90%	110.756	8,364
2	3x0 18V50SG	56.451	1.93%	55.361	8,367
3	2x0 LM6000	83.688	1.21%	82.673	9,403
4	2x1 LM6000	110.826	2.74%	107.787	7,207
5	1x0 LMS100	81.353	2.81%	79.064	9,009
6	1x0 7F.05	196.856	1.23%	194.435	9,691
7	1x1 7F.05 DB	281.916	2.55%	274.722	6,788
	1x1 7F.05 DB ON	298.444	2.50%	290.997	6,926

Table 4.1-5. Average Day, Part Load

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	56.451	2.36%	55.120	8,403
2	3x0 18V50SG	37.634	2.17%	36.816	8,388
3	2x0 LM6000	41.844	1.48%	41.224	9,429
4	2x1 LM6000	54.842	3.12%	53.129	7,311
5	1x0 LMS100	61.137	3.66%	58.903	9,647
6	1x0 7F.05	148.953	1.60%	146.573	10,433
7	1x1 7F.05 DB	221.849	2.96%	215.281	7,028

Table 4.1-6. Average Day, MECL

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	9.409	8.29%	8.629	9,829
2	3x0 18V50SG	9.409	5.72%	8.870	9,562
3	2x0 LM6000	21.116	2.85%	20.513	12,602
4	2x1 LM6000	30.369	4.62%	28.965	8,921
5	1x0 LMS100	40.834	5.34%	38.654	11,131
6	1x0 7F.05	100.160	2.33%	97.821	11,957
7	1x1 7F.05 DB	161.020	3.61%	155.212	7,459

Table 4.1-7. Winter Day, Full Load

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	112.902	1.90%	110.756	8,358
2	3x0 18V50SG	56.451	1.93%	55.361	8,361
3	2x0 LM6000	88.669	1.15%	87.651	9,318
4	2x1 LM6000	115.742	2.38%	112.984	7,223
5	1x0 LMS100	81.772	2.80%	79.483	8,995
6	1x0 7F.05	202.720	1.20%	200.295	9,626
7	1x1 7F.05 DB	288.054	2.30%	281.422	6,781
	1x1 7F.05 (NG) DB ON	304.618	2.31%	297.579	6,928

Table 4.1-8. Winter Day, Part Load

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	56.451	2.36%	55.120	8,397
2	3x0 18V50SG	37.634	2.17%	36.816	8,381
3	2x0 LM6000	44.335	1.40%	43.713	9,342
4	2x1 LM6000	56.804	2.77%	55.233	7,388
5	1x0 LMS100	61.462	3.61%	59.246	9,666
6	1x0 7F.05	153.222	1.56%	150.838	10,471
7	1x1 7F.05 DB	227.336	2.61%	221.401	7,059

Table 4.1-9. Winter Day, MECL

Alternative	Description	Plant Gross Output (MW)	Auxiliary Loads (%)	Plant Net Output (MW)	Net HHV Heat Rate (BTU/kw-hr)
1	6x0 18V50SG	9.409	8.29%	8.629	9,821
2	3x0 18V50SG (NG)	9.409	5.72%	8.870	9,554
3	2x0 LM6000 (NG)	22.362	2.70%	21.758	12,357
4	2x1 LM6000 (NG)	29.254	4.25%	28.011	9,594
5	1x0 LMS100 (NG)	41.054	5.22%	38.912	11,154
6	1x0 7F.05 (NG)	102.983	2.27%	100.641	12,196
7	1x1 7F.05 (NG) DB	166.658	3.20%	161.317	7,530

Heat balance diagrams depicting summer, average, and winter day full load and minimum load performance at new and clean plant performance are included in Appendix 1 for the simple cycle and combined cycle power plants.

4.2 Environmental Considerations

4.2.1 Emission Profiles/Rates

Plant emissions rates and air quality control equipment presented for each technology are those expected to be achievable and permittable in the State of Colorado based on the fuels and technologies applied. Emissions rates are provided below on a lb/MMBtu heat input and lb/MWH basis as well as on a ton per year (TPY) basis representing the total potential to emit for each technology assuming a 100 percent capacity factor. Ton per year values based upon an assumed capacity factor can be obtained by utilizing the unitized emissions rates. All emission values are estimates and should not be used for permitting purposes.

It should be noted that the EPA issued a final rule for Carbon Pollution Standards for new power plants in 2015. The final rule sets standard for natural gas-fired stationary combustion units serving a generator rated 25 MW or larger. The limit based on the performance of modern natural gas combined cycle units are:

- 1,000 lb CO_2/MWh gross for base load (typically combined cycle) units
- 120 lb/MMBtu for peaking (typically simple cycle) units

Each of the generation options under consideration will meet the proposed limits.

Air emissions for the proposed thermodynamic cycles are presented below in Tables 4.2-1 and 4.2-2. Emissions presented are based on the average annual conditions with the TPY values based on a 100 percent capacity factor of the facility. Startup and shutdown emissions have not been considered in these values at this time but will need to be considered for permitting.

Table 4.2-1. Emission Targets and Annual Potential to Emit (Fired Average Day Conditions).

Plant Emissions		**Alternative 1**	**Alternative 2**	**Alternative 3**	**Alternative 4**	**Alternative 5**	**Alternative 6**	**Alternative 7**
		6x0 18V50SG (NG)	**3x0 18V50SG (NG)**	**2x0 LM6000 (NG)**	**2x1 LM6000 (NG)**	**1x0 LMS100 (NG)**	**1x0 7F.05 (NG)**	**1x1 7F.05 (NG) DB**
Plant Heat Input (Summer), HHV	mmbtu/hr	926	463	817	816	715	1928	1908
Plant Net Output (Summer)	MW	111	55	88	113	79	200	281
Annual Hours	hr/year	775	775	775	4222	775	775	4222
NOx	ppmvd	7.2	7.2	2.0	2.0	2.0	2.0	2.0
	lb/mmbtu	0.027	0.027	0.007	0.007	0.007	0.007	0.007
	lb/MWH	0.222	0.222	0.069	0.053	0.066	0.071	0.050
	TPY	108	54	26	26	23	62	62
CO	ppmvd	16.0	16.0	2.5	2.5	5.0	1.0	1.0
	lb/mmbtu	0.036	0.036	0.006	0.006	0.011	0.002	0.002
	lb/MWH	0.300	0.300	0.052	0.040	0.101	0.022	0.015
	TPY	145	73	20	20	35	19	19
VOC	ppmvd	19.2	19.2	2.4	2.4	2.4	1.0	1.0
	lb/mmbtu	0.025	0.025	0.025	0.003	0.003	0.003	0.001
	lb/MWH	0.205	0.205	0.229	0.022	0.028	0.030	0.009
	TPY	99	50	88	11	10	26	11
Particulate Matter PM10 Total	lb/mmbtu	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057
	lb/MWH	0.0474	0.0474	0.0529	0.0410	0.0511	0.0546	0.0385
	TPY	23	12	20	20	18	48	47
CO2	lb/mmbtu	118	118	118	118	118	118	118
	lb/MWH	986.2579	986.5469	1099.4937	852.3708	1061.4473	1135.8514	800.1613
	TPY	478,446	239,220	422,107	421,812	369,526	996,471	986,303

4.2.2 Water Supply/Discharge

Table 4.2-3 summarizes water consumption and discharge for each of the options based on reasonable recycling and reuse of water. The flow rates are indicative and assume a wastewater discharge option is available on-site.

Table 4.2-3. Natural Gas I/C Engine Water Consumption and Discharge.

Alternative	Description	Evap Cooler Water Consumption (Gallon/MWH)	Cycle Water Consumption (Gallon/MWH)	Misc Water Consumption (Gallon/MWH)	Total Water Consumption (Gallon/MWH)	Water Discharge Rate (Gallon/MWH)
1	6x0 18V50SG (NG)	0	0	0.14	0.14	0.14
2	3x0 18V50SG (NG)	0	0	0.29	0.29	0.29
3	2x0 LM6000 (NG)	20	0	0.19	20	4.18
4	2x1 LM6000 (NG)	15	6	0.89	23	10.16
5	1x0 LMS100 (NG)	17	0	0.20	17	3.58
6	1x0 7F.05 (NG)	16	0	0.08	16	3.24
7	1x1 7F.05 (NG) DB	11	5	0.33	17	7.64

5. Fuel Supply Requirements

Fuel supply requirements for each option are summarized below in Table 5.0-1. Performance heating requirements are also presented for the F class CTG options, with the heating requirements sourced from the HRSG IP economizer.

Peak fuel consumption rates are representative of plant operation at the duct fired peak equipment fuel consumption heat balance operating point modeled in this evaluation.

Table 5.0-1. Natural Gas Supply Requirements.

Alternative	Description	Gas Supply Pressure (psia)	Fuel Gas Performance Heating (F)	Peak Fuel Consumption Rate, HHV (mmBTU/hr)	Peak Fuel Consumption Rate, HHV (kscf/day)
1	6x0 18V50SG (NG)	101	NA	926	22,275
2	3x0 18V50SG (NG)	101	NA	463	11,137
3	2x0 LM6000 (NG)	655	NA	817	19,652
4	2x1 LM6000 (NG)	655	NA	816	19,638
5	1x0 LMS100 (NG)	873	NA	715	17,204
6	1x0 7F.05 (NG)	423	NA	1928	46,393
7	1x1 7F.05 (NG) DB	423	365	2062	49,608

No gas compression costs or auxiliary loads have been included for any of the options. It is assumed that adequate gas pressure and capacity is available at the site boundary.

6. Aurora Model Input

Appendix 4 includes the Aurora model input summary sheet. This sheet summarizes O&M costs, project costs emissions, and plant performance for input into the Aurora model.

APPENDIX 1 – HEAT BALANCES

APPENDIX 2 – PROJECT COST ESTIMATE SUMMARIES

APPENDIX 3 – O&M SUMMARY

		Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6	Alternative 7
		6x0 18V50SG (NG)	3x0 18V50SG (NG)	2x0 LM6000 (NG)	2x1 LM6000 (NG)	1x0 LMS100 (NG)	1x0 7F.05 (NG)	1x1 7F.05 (NG) DB
Fixed O&M								
Hourly Plant Staffing	($1,000/yr)	$ 200	$ 200	$ 200	$ 1,800	$ 200	$ 200	$ 1,800
Salaried Plant Staffing	($1,000/yr)	$ 140	$ 140	$ 140	$ 840	$ 140	$ 140	$ 840
Insurance	($1,000/yr)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Property Taxes	($1,000/yr)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fixed Maintenance Agreement Costs	($1,000/yr)	$ 36	$ 36	$ 181	$ 186	$ 73	$ 240	$ 240
Major Equipment Repair / Maintenance Costs	($1,000/yr)	$ 135	$ 81	$ 99	$ 187	$ 116	$ 170	$ 370
Misc. Operating Expense	($1,000/yr)	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150	$ 150
Total Annual First Year Fixed Operating Costs	**($1,000/yr)**	**$ 661**	**$ 607**	**$ 770**	**$ 3,163**	**$ 679**	**$ 900**	**$ 3,400**
Total Annual First Year Fixed Operating Costs	**$/kW**	**$ 5.96**	**$ 10.97**	**$ 9.32**	**$ 29.34**	**$ 8.59**	**$ 4.63**	**$ 12.38**
Variable O&M								
Ammonia Consumption	tph (19%)	0.28	0.14	0.06	0.06	0.06	0.16	0.15
Ammonia Cost	$/ton NH3 (19%)	$ 167	$ 167	$ 167	$ 167	$ 167	$ 167	$ 167
Annual Ammonia Cost	($1,000/yr)	$ 36	$ 18	$ 8	$ 45	$ 8	$ 20	$ 108
Clarified Water Consumption	gal/hr	16	16	1665	1766	1351	3088	3159
Clarified Water Cost	$/kgal	$ 1.50	$ 1.50	$ 1.50	$ 1.50	$ 1.50	$ 1.50	$ 1.50
Annual Clarified Water Cost	($1,000/yr)	$ 0.02	$ 0.02	$ 1.94	$ 11.18	$ 1.57	$ 3.59	$ 20.01
Demin Water Consumption	gal/hr	0	0	0	666.864944	0	0	1394.07007
Demin Water Cost	$/kgal	$ 3.50	$ 3.50	$ 3.50	$ 3.50	$ 3.50	$ 3.50	$ 3.50
Annual Demin Water Cost	($1,000/yr)	$ -	$ -	$ -	$ 10	$ -	$ -	$ 21
Water Discharged	gal/hr	16	16	346	1096	283	630	2098
Water Discharge Cost	$/kgal	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
Annual Water Discharge Cost	($1,000/yr)	$ 0.01	$ 0.01	$ 0.27	$ 4.63	$ 0.22	$ 0.49	$ 8.86
Cycle Steam Rate	Ton/hr	0	0	0	107	0	0	264
Cost of Cycle Chemicals	$/ton of steam	$ 0.015	$ 0.015	$ 0.015	$ 0.015	$ 0.015	$ 0.015	$ 0.015
Annual Cost of Cycle Chemicals	($1,000/yr)	$ -	$ -	$ -	$ 7	$ -	$ -	$ 17
Engine Oil Consumption	gal/hr	9	5	0	0	0	0	0
Engine Oil Cost	$/gallon	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 7.00
Annual Cost of Oil	($1,000/yr)	$ 51	$ 26	$ -	$ -	$ -	$ -	$ -
Variable Maintenance Agreement Cost	($1,000/yr)	$ 358	$ 179	$ 322	$ 1,756	$ 328	$ 465	$ 1,689
Plant Variable Operating Costs	($1,000/yr)	$ 20	$ 10	$ 20	$ 356	$ 18	$ 157	$ 3,632
Total Annual First Year Variable Operating Costs	**($1,000/yr)**	**$ 465**	**$ 232**	**$ 475**	**$ 2,190**	**$ 355**	**$ 646**	**$ 5,495**
Total Annual First Year Variable Operating Costs	**$/MWH**	**$ 5.42**	**$ 5.42**	**$ 6.10**	**$ 4.81**	**$ 5.80**	**$ 4.29**	**$ 4.74**

APPENDIX 4 – AURORA MODEL INPUT SUMMARY

AURORA MODEL INPUT SUMMARY

Type/Name	Name Plate Size (MW)	Total Project Cost $/kW	Total Project Cost $000	Annual FOM ($/MW/week)	Fuel Type	Variable O&M $/MWh	Forced Outage %	Minimum Capacity %	Min Up Time (hr)	Min Down Time (hr)	Ramp Rate (MW/Min)	Ramp Rate	Summer Cap (MW)	Winter Cap (MW)	Annual Max	Overall Max	Peak Credit factor	Start Fuel Type	Start Fuel Amount mmbtu/MW/Start	Start Up Costs $/MW/Start	NOx Emission lb/mmbtu	SOx Emission lb/mmbtu	CO2 Emission lb/mmbtu
6x0 18V50SG (NG)	111	$ 1,252	$ 138,639	$ 115	NG	$ 5.42	3.30%	8%	1	0.25	96		104	111			NA	NG	0.36	$0	0.0265	0.0014	118
3x0 18V50SG (NG)	55	$ 1,389	$ 76,917	$ 211	NG	$ 5.42	3.30%	16%	1	0.25	48		52	55			NA	NG	0.36	$0	0.0265	0.0014	118
2x0 LM6000 (NG)	83	$ 1,184	$ 97,874	$ 179	NG	$ 6.10	2.40%	25%	1	0.25	100		78	88			NA	NG	3.91	$0	0.0074	0.0014	118
2x1 LM6000 (NG)	108	$ 1,748	$ 188,418	$ 564	NG	$ 4.81	2.03%	27%	4	1	100		101	113			NA	NG	7.27	$0	0.0074	0.0014	118
1x0 LMS100 (NG)	79	$ 1,421	$ 112,344	$ 165	NG	$ 5.80	2.40%	49%	1	0.25	50		74	79			NA	NG	0.77	$0	0.0074	0.0014	118
1x0 7F.05 (NG)	194	$ 715	$ 139,042	$ 89	NG	$ 4.29	2.40%	50%	1	0.25	20		190	200			NA	NG	1.61	$0	0.0074	0.0014	118
1x1 7F.05 (NG) DB	275	$ 1,322	$ 363,199	$ 238	NG	$ 4.74	3.88%	53%	4	1	20		269	281			NA	NG	6.78	$44	0.0074	0.0014	118

AURORA MODEL INPUT SUMMARY

Summer Heat Rate - Total Heat Rate at Load Point (not incremental)								Winter Heat Rate - Total Heat Rate at Load Point (not incremental)								
Min Block		Part Load		Full Load - Unfired		Duct Firing		Min Block		Part Load		Full Load - Unfired		Duct Firing		
#1 Heat Rate btu/kWhr	**#1 HR Segment Size MW**	**#2 Heat Rate btu/kWhr**	**#2 HR Segment Size MW**	**#3 Heat Rate btu/kWhr**	**#3 HR Segment Size (MW)**	**#4 Heat Rate btu/kWhr**	**#4 HR Segment Size (MW)**	**#1 Heat Rate btu/kWhr**	**#1 HR Segment Size MW**	**#2 Heat Rate btu/kWhr**	**#2 HR Segment Size MW**	**#3 Heat Rate btu/kWhr**	**#3 HR Segment Size (MW)**	**#4 Heat Rate btu/kWhr**	**#4 HR Segment Size (MW)**	**Earliest Online Date (months from current date)**
9,844	8.63	8,518	51.68	8,475	103.87			9,821	8.63	8,397	55.12	8,358	110.76			21
9,576	8.87	8,501	34.52	8,478	51.92			9,554	8.87	8,381	36.82	8,361	55.36			21
13,948	15.90	10,173	32.09	9,555	78.05			12,357	21.76	9,342	43.71	9,318	87.65			21
9,639	23.00	7,782	41.92	7,388	100.86			9,594	28.01	7,388	55.23	7,223	112.98			32
11,754	33.28	10,131	50.76	9,143	74.31			11,154	38.91	9,666	59.25	8,995	79.48			21
12,366	89.80	10,724	134.64	9,773	189.75			12,196	10.06	10,471	150.84	9,626	200.29			21
7,558	145.40	7,083	201.67	6,825	268.86	6,960	284.86	7,530	161.32	7,059	221.40	6,781	281.42	6,928	297.58	34

APPENDIX 5 – APPROXIMATE START-UP TIMES

Start Type:	Cold Start			Warm Start			Hot Start			Notes
Facility Type	Down Time	Time to Min CTG Load (1)	Time to Full Load	Down Time	Time to Min CTG Load (1)	Time to Full Load	Down Time	Time to Min CTG Load (1)	Time to Full Load	
RICE (6x0 18V50SG)	Any Duration	5-10 minutes								4
RICE (3x0 18V50SG)	Any Duration	5-10 minutes								4
Simpe Cycle (2x0 LM6000)	Any Duration	10 minutes								
Simpe Cycle (1x0 LMS100)	Any Duration	10 minutes								
Simpe Cycle (Frame CTG)	Any Duration	20 minutes								
Combined Cycle (2x1 LM6000)	> 60 Hours	10	150	10 to 60 Hours	10	80	<10 Hours	10	60	2, 5, 6
Combined Cycle (1x1 Frame CTG)	> 60 Hours	60	210	10 to 60 Hours	40	100	<10 Hours	40	100	2, 5, 6

NOTES:

1. Represents time to minimum CTG load with export power to the grid. Additional time will be required for the emissions systems to be fully operational and the combined cycle plant to be in full emissions compliance
2. Cold start times based on auxiliary boiler in hot standby mode.
3. Cold start can be made ready for a warm start if auxiliary boiler is kept operational and sparging steam delivered to keep HRSG and STG warm and steam seals maintained.
4. RICE start time will depend on plant readiness; i.e. maintaining lube oil circulation and temp, readiness of compressed air and cooling systems.
5. All simple and combined cycle start times require NFPA purge credit to be met. This can easily be maintained by purging unit once per week.
6. Combined cycle start times are based on an "emissions start" design with the facility designed to ramp quickly to minimum emissions compliance load. Start times are not based on a "Fast start" facility design will reduce start times but negatively impact the maintenance cycle and associated costs.