JEA

Final Draft 2019 Integrated Resource Plan

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EXHIBIT 37

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EXECUTIVE SUMMARY

This report documents the 2019 Integrated Resource Plan (IRP) developed for JEA's electric system over the 2020 through 2050 period. The IRP was developed to assist JEA in determining the most cost-effective type of generating unit to provide firm power to JEA in the 2025 to 2030 timeframe, with consideration of potential retirement of JEA's Northside 3 as the primary driver for projected capacity requirements[1].

ES.1 IRP Approach

A scenario approach was utilized for the IRP, which allowed for simultaneous consideration of variations to several of the reference set of inputs (referred to herein as the Baseline Scenario). Table ES-1 illustrates the various scenarios considered in this IRP. Scenarios were developed to address uncertainties related to:

- Projected load growth (both peak demand and annual energy requirements)
- Penetration of plug-in electric vehicles and increased electrification in general
- Net metering, energy efficiency, energy conservation, and direct load control
- Future environmental regulation and clean energy standards
- Estimated capital costs for new generating units
- Projected natural gas prices
- Potential future solid-fuel unit retirements

[1] It should be noted that this IRP was initiated in the Spring of 2018 and reflects assumptions and inputs that were reasonable and prudent based on the timeframe in which the IRP was undertaken.

Table ES-1
Summary of IRP Scenarios

Area	Metric	Baseline Scenario	Load Erosion Scenario	Increased Electrfication Scenario	Green Economy Scenario
Financial	Interest During Construction & Discount Rate	4.50%	6%	4.50%	4.50%
	Escalation Rate	2.00%	3.00%	2.00%	2.00%
Demand	Total Net Energy Requirements Forecast	AAGR: 0.87%	Energy requirements decline by 1.0% /year for 10 years; then no growth	Energy requirements increase at 2.0%/year until achieve +20% over Baseline forecast; then Baseline AAGR of 0.87% thereafter {See Comment}	AAGR: 0.89%
	Net Firm Peak Demand Forecast	AAGR Winter: 0.86% AAGR Summer: 0.70%	Winter and Summer net firm peak demand declines at 1.0% for 10 years; then no growth	Winter and Summer net firm peak demand increase at 2.0%/year until achieve +20% over Baseline forecast; Baseline Winter and Summer AAGR thereafter	AAGR Winter: 1.6% AAGR Summer: 1.6%
	EE/Conservation	Current Portfolio	Embedded in Energy Forecast	Embedded in Energy Forecast	Embedded in Energy Forecast
	Direct Load Control	None	None	None	None
	Interruptible Load	Current Portfolio	Embedded in Peak Demand Forecast	Embedded in Peak Demand Forecast	Embedded in Peak Demand Forecast
	PEV	0.5% by 2027 3.6% by 2046	Embedded in Energy and Peak Demand Forecasts	Embedded in Energy and Peak Demand Forecasts	Embedded in Energy and Peak Demand Forecasts
	Net Metering	Current Portfolio	Embedded in Energy and Peak Demand Forecasts	Embedded in Energy and Peak Demand Forecasts	Embedded in Energy and Peak Demand Forecasts
Environmental Regulations	Carbon Tax Rate	None	None	None	~ $11.50/ton in 2020, increasing at 5% annually
	Clean Energy Standard (CES)	None	None	None	Reflect 30% carbon neutral by 2030
Supply	Fuel Cost & Availability	Gas supply remains adequate with moderate pricing	Gas supply remains adequate with moderate pricing	Gas supply remains adequate with moderate pricing	Gas supply inadequate with high pricing
	Construction Cost	Costs increase at inflation	Costs increase at inflation	Costs increase at inflation	Costs increase at inflation through 2020, inflation + 1% thereafter
	Unit Retirements	Northside 3: 2025; Solid Fuel: none expected	Northside 3: 2025; Solid Fuel: none expected	Northside 3: 2025; Solid Fuel: none expected	Northside 3: 2025; Solid Fuel: 2030

ES.2 Projected Capacity Requirements

Projected capacity requirements reflected in this IRP are based on consideration of numerous factors, including JEA's existing capacity resources (both wholly-owned, jointly owned, and purchased power resources), forecasts of seasonal (summer and winter) peak demand, and JEA's planning reserve margin (15 percent). Each of these factors is discussed in more detail throughout this IRP, and variations to the base assumptions are reflected in the scenario and sensitivity analyses performed for this IRP. Figure ES-1 illustrates the projected capacity requirements for the Baseline Scenario under the base load forecast.

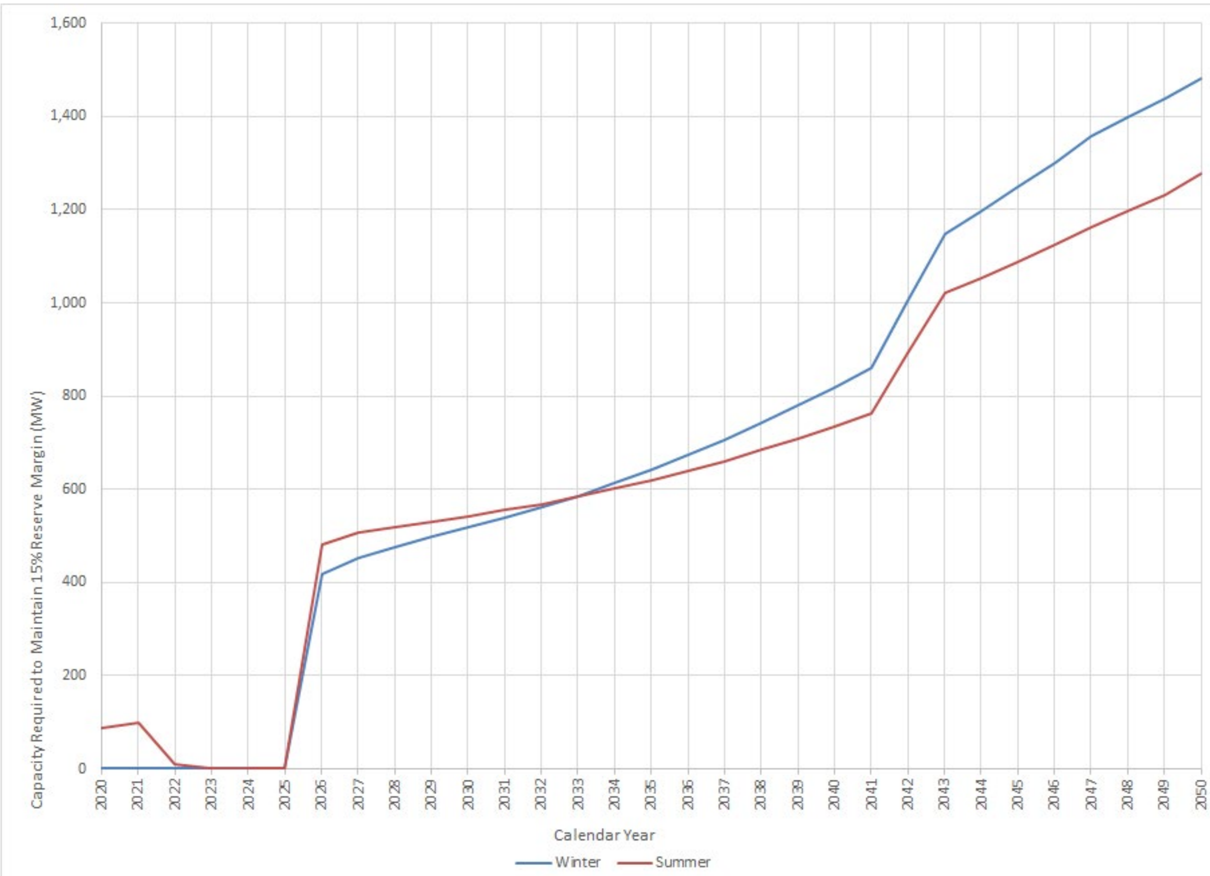

Figure ES-1
Projected Capacity Requirements – Baseline Scenario and Base Load Forecast

ES.3 Supply-Side Options

A wide range of natural gas and solar photovoltaic options were considered as potential supply-side options for evaluation in this IRP. The natural gas options represent various technologies (i.e. reciprocating engines, aeroderivatives, and combustion turbines) in different configurations (simple cycles and combined cycles). Solar PV technologies included utility scale PV with and without battery storage, and reflected projected continuation of decreases in equipment and construction costs. The supply-side options evaluated in this IRP are summarized below.

- Natural Gas-Fired Simple Cycle Combustion Turbines, Aeroderivatives, and Reciprocating Engines
    - General Electric (GE) 7F.05 simple cycle combustion turbine
    - GE 7HA.01 simple cycle combustion turbine
    - GE 7HA.02 simple cycle combustion turbine
    - GE LMS100 simple cycle aeroderivative
    - GE LM6000 simple cycle aeroderivative (2 units installed simultaneously)
    - GE Jenbacher J920 Flextra reciprocating engine (5 units installed simultaneously)
    - Wartsila 18V50SG reciprocating engine (5 units installed simultaneously)
- Natural Gas-Fired Combined Cycle Combustion Turbines
    - Existing GEC GE 7F.03 simple cycle combustion turbines upgraded to include a GE 7F.05 compressor and advanced gas path (AGP) upgrade and converted to either 1x1 or 2x1 combined cycle configuration
    - GE 7F.05 1x1 combined cycle
    - GE 7HA.01 1x1 combined cycle
    - GE 7HA.01 2x1 combined cycle
    - GE 7HA.02 1x1 combined cycle
    - GE 7HA.02 2x1 combined cycle (both wet cooling and air cooled condenser (ACC) alternatives)
    - GE 7HA.02 3x1 combined cycle
- Solar Photovoltaic (with and without battery storage)
    - 74.9 MW (AC) solar array, with and without battery storage

ES.4 Scenarios and Sensitivities

The following provides a summary the scenarios previously presented in Figure ES-1.

- **Baseline Scenario** – The Baseline Scenario represents a projection of the future based on current conditions, and reflects relatively low average annual growth rates for both annual energy requirements (0.87 percent) and summer and winter peak demand (0.70 percent and 0.86 percent, respectively). Northside 3 is assumed to retire in September 2025 due to environmental considerations and the age of the unit. No new environmental regulations or clean energy standards are assumed, and (except for Northside 3) none of JEA's generating units are assumed to retire. The following sensitivities were considered within the Baseline Scenario: high load growth, low load growth, high natural gas prices, and low natural gas prices.
- **Load Erosion Scenario** – The Load Erosion Scenario represents a future in which both annual energy requirements and summer and winter peak demands decline at 1.0 percent annually for 10 years, and then remain constant for the remainder of the evaluation period. Other assumptions are identical to those in the Baseline Scenario, except that the Load Erosion Scenario includes higher interest during construction, present worth discount, and general escalation rates.
- **Increased Electrification Scenario** – The Increased Electrification Scenario represents a future in which electrification increases in the near term such that both annual energy requirements and summer and winter peak demands increase at 2.0 percent annually until reaching levels that are 20 percent higher than in the Baseline Scenario, and then increase at the average annual growth rates from the Baseline Scenario thereafter. Other assumptions are identical to those in the Baseline Scenario.
- **Green Economy Scenario** – The Green Economy Scenario represents a future in which increased

environmental regulations result in a carbon tax, clean energy standards, and high natural gas prices, with JEA retiring Northside 3 in September 2025 and retiring all of its other solid fuel units in 2030. Costs for construction of new generating units increase 1.0 percent more than the general escalation rate. Forecast annual energy requirements are similar to the Baseline Scenario, but summer and winter peak demand are assumed to increase at 1.6 percent annually.

The following figures are presented to illustrate the differences between load forecasts and natural gas price projections evaluated in this IRP within each of the scenarios and the sensitivities performed within the Baseline Scenario.

- Figure ES-2 presents a comparison of the summer peak demand forecasts. Note that the forecasts for the various scenarios and sensitivities were developed to reflect deviations based upon the base case summer peak demand forecast.
- Figure ES-3 presents a comparison of the winter peak demand forecasts. Note that the forecasts for the various scenarios and sensitivities were developed to reflect deviations based upon the base case winter peak demand forecast.
- Figure ES-4 presents a comparison of the annual net energy for load forecasts. Note that the forecasts for the various scenarios and sensitivities were developed to reflect deviations based upon the base case net energy for load forecast.
- Figure ES-5 presents a comparison of the natural gas price projections. Note that the high natural gas price projections were used for both the high natural gas sensitivity as well as the Green Economy scenario. As discussed in Section 7.0 of this IRP, the base case natural gas price projections were developed utilizing information from the 2018 United States Energy Information (EIA) Annual Energy Outlook 2018 (AEO 2018), and the high and low price sensitivities were developed based on sensitivity cases included in AEO2018.

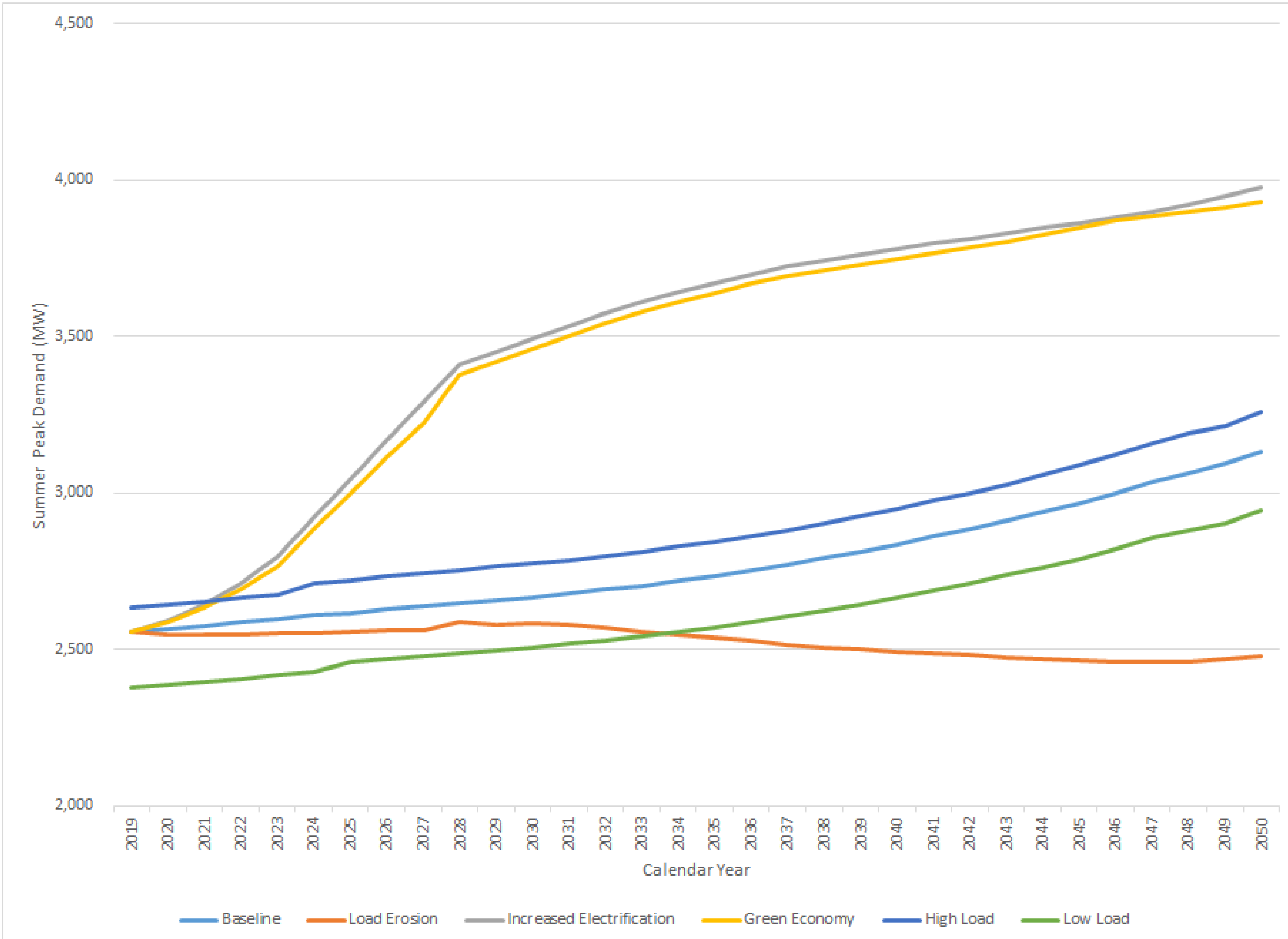

Figure ES-2
Comparison of Summer Peak Demand Forecasts

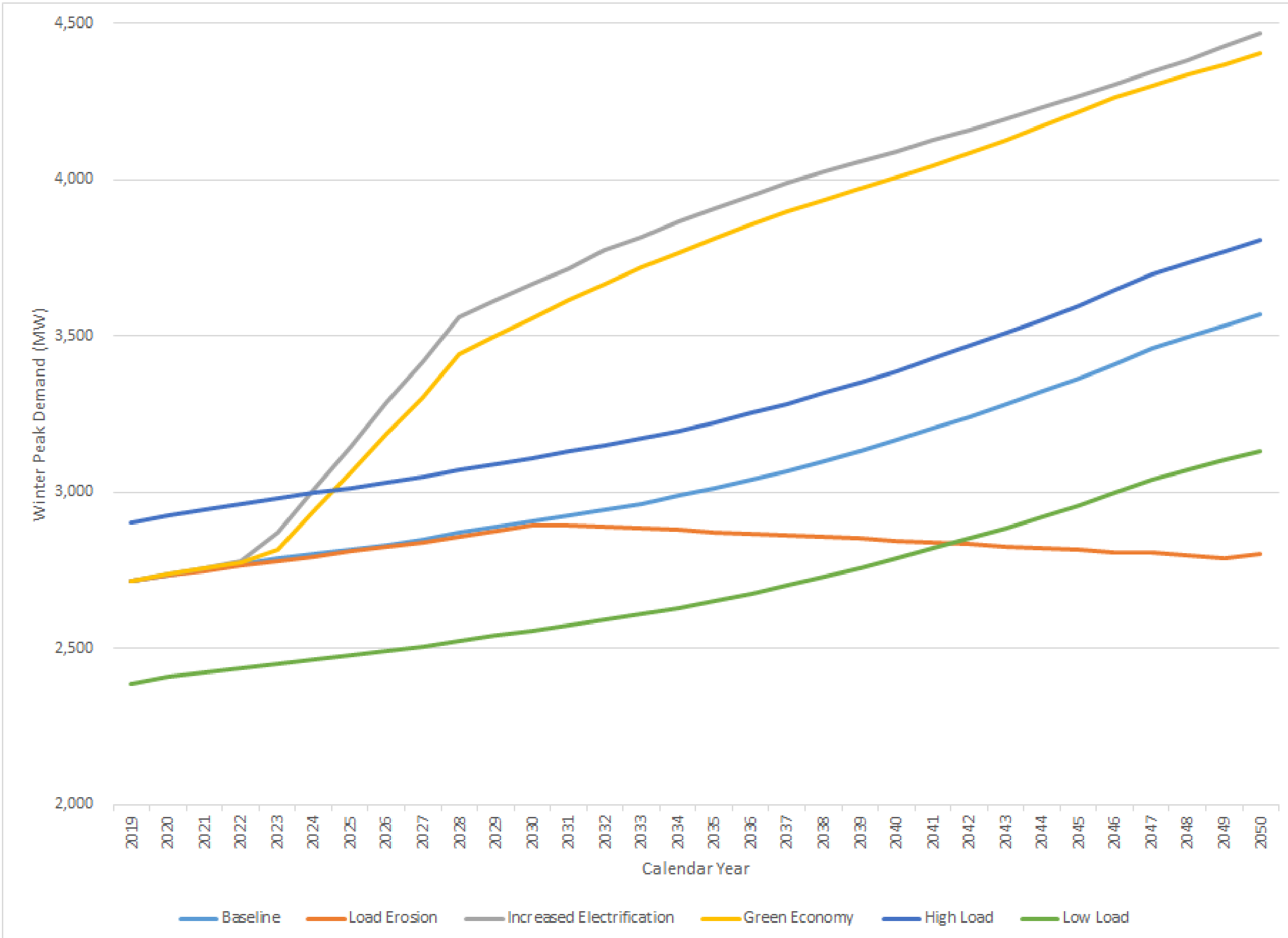

Figure ES-3
Comparison of Winter Peak Demand Forecasts

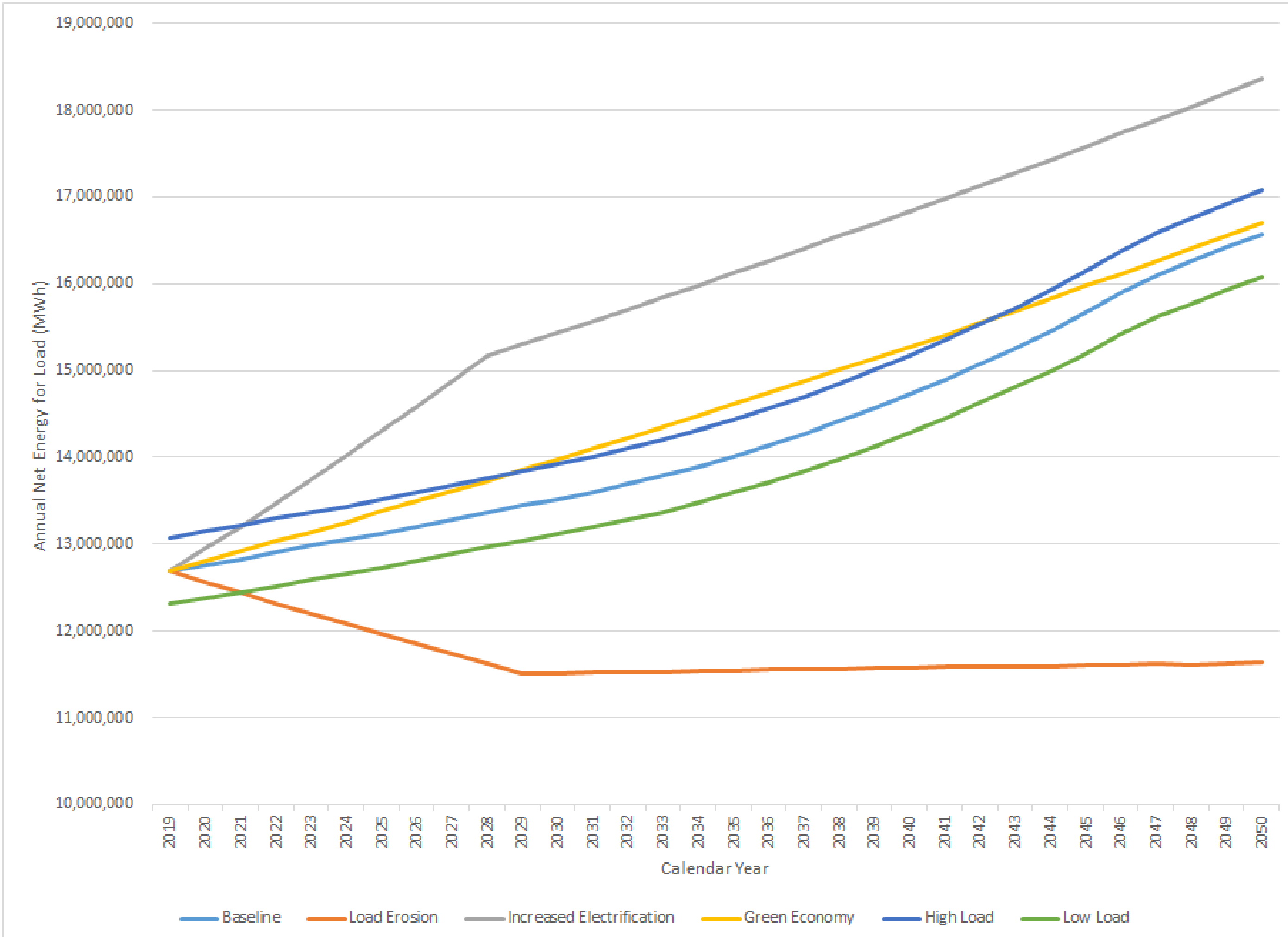

Figure ES-4
Comparison of Annual Net Energy for Load Forecasts

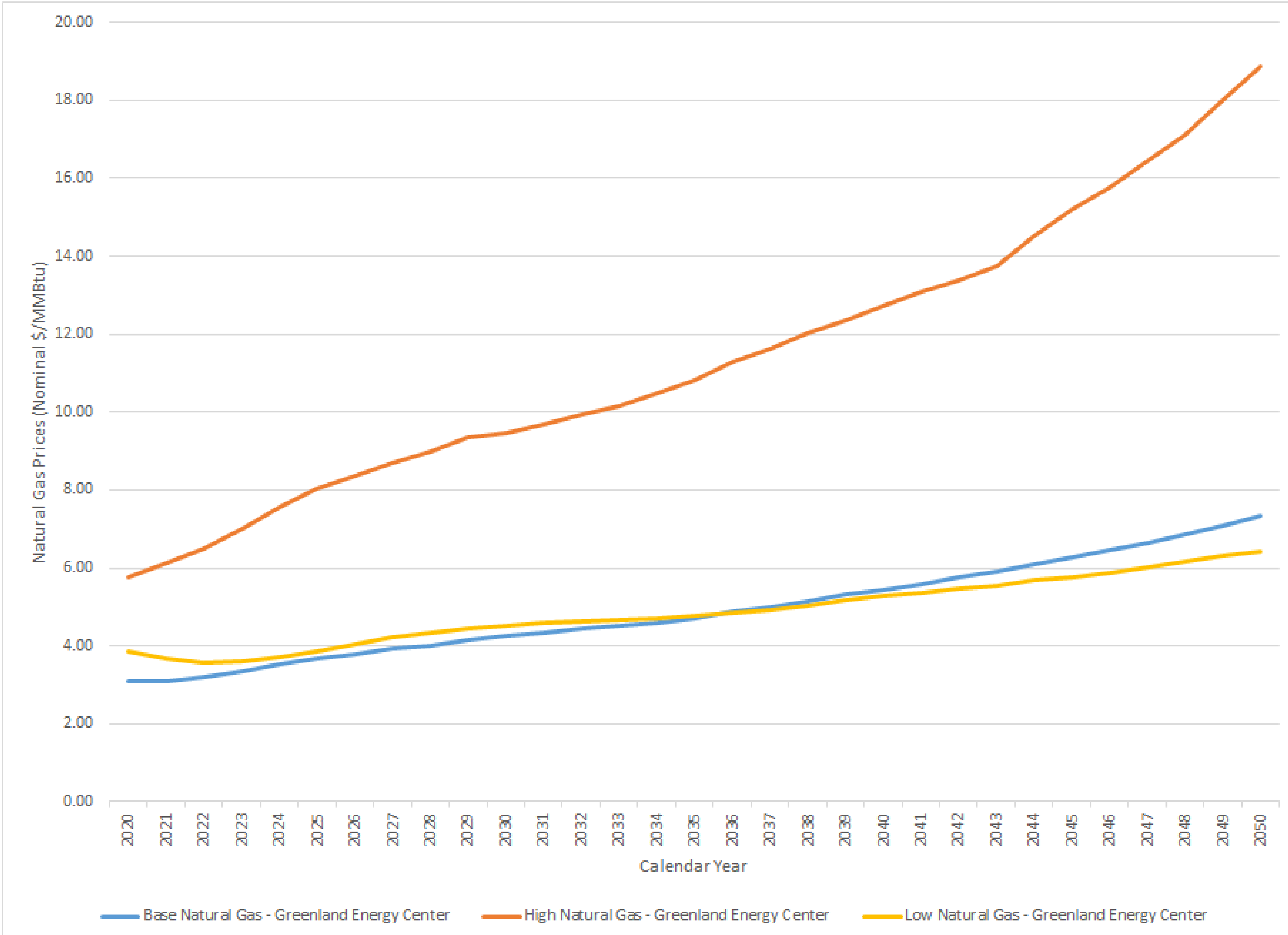

Figure ES-5
Comparison of Natural Gas Price Projections

ES.5 Modeling and Economic Evaluations

The economic evaluations performed for this IRP include an initial screening of the supply-side options as well as detailed generation expansion and production cost modeling. The initial screening, performed as a levelized cost of energy (LCOE) analysis, was utilized to evaluate the various supply-side options and eliminate, or screen out, options that were not economic or appropriate for consideration in the generation expansion planning (and subsequent production cost modeling performed based on the generation expansion planning modeling). Reducing the number of supply-side options through the LCOE analysis allows for more efficient generation expansion planning modeling as the modeling is performed based on a more manageable number of supply-side options.

ES.5.1 Supply-Side Screening

The LCOE analysis considered capital costs, operating costs, and fuel costs (as appropriate for each supply-side option) and expresses the total annual cost and corresponding energy generation on a nominal (current year) and present value basis. The cumulative present value costs are divided by the sum of the annual present worth factors to calculate the lifecycle levelized cost of energy for each option. Such an approach is widely used in comparing the relative economics of various supply-side options to determine if one (or more) option may be consistently more costly than the others across a range of possible capacity factors, allowing an initial list of supply-side options to be reduced to a smaller number to be considered in subsequent evaluations.

ES.5.2 Modeling and Economic Evaluations

Resource plans were developed for each scenario and sensitivity using the ABB/Ventyx Strategist model to evaluate and select the overall least-cost generating unit additions from several alternatives appropriate for JEA's consideration, including new simple and combined cycle units as well as conversion of the existing Greenland Energy Center simple cycle units. All resource plans include the 250 MW of solar power purchase agreements (PPAs) to which JEA has committed beginning in the 2020/21 timeframe, 200 MW of nuclear from the Vogtle PPA for a 20-year period (100 MW beginning in 2021, followed by another 100 MW beginning in 2022), and the continued operation of the current fleet, except as noted in the scenarios. Following determination of the least-cost resource plan for each scenario and sensitivity, the ABB/Ventyx PROMOD model was used for production cost modeling, from which annual costs and cumulative present worth costs (CPWC) were developed and used as the basis for economic comparisons.

The following provides a general overview of the least-cost resource plans for each of the scenarios evaluated in this IRP:

- **Baseline Scenario** – In the Baseline Scenario, the need for additional capacity to maintain reserve margin requirements is first projected to occur in the 2025/26 timeframe due primarily to the assumed retirement of Northside 3. The least-cost resource plan includes a new 1x1 H-class combined cycle located at JEA's existing Greenland Energy Center to meet the initial capacity requirements, followed by the addition of several F-class simple cycle combustion turbines over the remainder of the evaluation period. It should be noted that in the Baseline Scenario the CPWC of alternative expansion plans (which include conversion of either one or both of the existing Greenland Energy Center simple cycle units to 1x1 or 2x1 combined cycle units, respectively) are within less than 2.0 percent of the CPWC of the least-cost resource plan, and the CPWC of a resource plan that includes continued operation of Northside 3 through the study period is within

1.0 percent of the CPWC of the least-cost plan. In general, these results are consistent across each of the sensitivities evaluated within the Baseline Scenario.

- **Load Erosion Scenario** – Although projected peak demand is lower in the Load Erosion Scenario than in the Baseline Scenario, the need for additional capacity to maintain reserve margin requirements is still projected to occur in the 2025/26 timeframe due to the assumed retirement of Northside 3. The least-cost resource plan includes a new 1x1 H-class combined cycle located at JEA's existing Greenland Energy Center to meet the initial capacity requirements, followed by the addition of an F-class simple cycle combustion turbine in 2042. It should be noted that in the Load Erosion Scenario the CPWC of alternative expansion plans (which include conversion of either one or both of the existing Greenland Energy Center simple cycle units to 1x1 or 2x1 combined cycle units, respectively) are within approximately 3.0 percent of the CPWC of the least-cost resource plan, and the CPWC of a resource plan that includes continued operation of Northside 3 through the study period is within 2.0 percent of the CPWC of the least-cost plan.
- **Increased Electrification Scenario** – The need for additional capacity to maintain reserve margin requirements is higher in the Increased Electrification Scenario than the Baseline Scenario, due to higher near-term annual growth in peak demands. The least-cost resource plan includes continued operation of Northside 3 through the study period as well as a new 1x1 H-class combined cycle located at JEA's existing Greenland Energy Center, followed by the addition of several simple cycle units throughout the evaluation period. It should be noted that in the Increased Electrification Scenario the CPWC of alternative expansion plans (which include conversion of either one or both of the existing Greenland Energy Center simple cycle units to 1x1 or 2x1 combined cycle units, respectively) are within approximately 3.0 percent of the CPWC of the least-cost resource plan, and the CPWC of a resource plan that includes retirement of Northside 3 in 2025 is within 1.0 percent of the CPWC of the least-cost plan.
- **Green Economy Scenario** – The need for additional capacity to maintain reserve margin requirements is higher in the Green Economy Scenario than in the Baseline Scenario, due to higher annual growth in peak demand. Longer term, the need for capacity is driven by assumed retirement of all JEA's solid-fuel resources in 2030. The economics reflected in this scenario are driven by several factors that tend to favor the addition of new, more efficient combined cycle generation as well as solar power when compared to the other scenarios. In particular, the combination of higher natural gas prices, a carbon tax, and a clean energy standard (assumed to be 30 percent by the year 2030) support the addition of new efficient generation and solar power. The least-cost resource plan includes continued operation of Northside 3 through the study period and conversion of one of the existing simple cycle units at Greenland Energy Center to a 1x1 combined cycle, followed by the addition of several simple cycle units and a new 1x1 H-class combined cycle unit, as well as a significant amount of solar power. The CPWC of the least-cost resource plan is essentially identical (approximately 0.03 percent difference) to the CPWC of the resource plan that includes retirement of Northside 3 and the addition of a new 1x1 H-class combined cycle as the initial capacity addition. Similarly, the CPWC of resource plans that include retirement of Northside 3 in 2025 and either a 1x1 or 2x1 conversion of the existing simple cycle units at the Greenland Energy Center are within approximately 0.06 percent of the CPWC of the least-cost resource plan. It should be noted that the CPWC of a resource plan that includes continued operation of Northside 3 through the study period, but no new combined cycle capacity, is 3.4 percent higher than the CPWC of the least-cost resource plan.

ES.6 Conclusions

Based on the evaluations performed for and discussed throughout this IRP, the following conclusions can be reached. Tables ES-2 and ES-3, presented at the end of this section, summarize the potential decisions and resource considerations within various timeframes and across the scenarios evaluated in this IRP.

- JEA's near-term capacity requirements are driven primarily by retirement of Northside 3, which is assumed to occur in September 2025. Given this assumption, a significant amount of new capacity is projected to be required in the 2025/26 timeframe in order to maintain JEA's reserve margin and meet capacity requirements.
- Specific to the Baseline Scenario and with the base load forecast and natural gas price projections, the following observations can be made:
    - The CPWC of the expansion plan that includes retirement of Northside 3 and a new 7HA.02 1x1 combined cycle in 2025 is the least cost expansion plan, but the other expansion plans are very close in CPWC.
        - The CPWC of the expansion plan with continued operation of Northside 3 is within 1 percent of the CPWC of the least cost expansion plan.
        - The CPWC of the expansion plan that includes conversion of both of the existing simple cycle combustion turbines at the Greenland Energy Center in 2025 is approximately 1.3 percent higher than the CPWC of the least-cost expansion plan.
        - The CPWC of the expansion plan that includes conversion of one of the existing simple cycle combustion turbines at the Greenland Energy Center in 2025 is approximately 1.9 percent higher than the CPWC of the least-cost expansion plan.
        - The CPWC of the expansion plan with Retirement of Northside 3 and the Northside simple cycle units is approximately 3.4 percent higher than the least cost expansion plan.
- In general, regardless of the scenario or sensitivity considered, the CPWCs of the various expansion plans are close to one another.
    - When comparing expansion plans including continued operation of Northside 3, retirement of Northside 3, and conversion of the Greenland Energy Center simple cycle units to combined cycle:
        - Comparisons of the CPWCs of expansion plans within each scenario and sensitivity indicates that the CPWCs of the expansion plans are within approximately 1 percent to 3 percent of one another.
        - The difference in CPWCs between expansion plans is often less than 1 percent.
        - Expansion plans that include retirement of Northside 3 and new combined cycles (i.e. either a new 1x1 combined cycle or conversion of one or both of the existing Greenland Energy Center simple cycle units to combined cycle) in 2025/26 timeframe are generally lowest in CPWC; the differentials in CPWC between these plans are small.
- There are other important considerations beyond CPWC related to retirement or continued operation of Northside 3, including:
    - Safety
    - Comprehensive condition assessment on Northside 3
    - Applicable regulations including and other than 316(b)
    - Reliability (expected near-term and longer term)
    - Capital investment

    - Efficiency (qualitative consideration, as efficiency of the unit in terms of fuel usage and operating costs is reflected in the CPWC evaluations)
    - Operational flexibility, particularly when considering potential future integration of additional solar PV resources
- The IRP evaluated new solar PV resources, with and without storage, and reflected the anticipated continued downward trend in solar pricing. Depending upon the scenario and sensitivity considered, it appears that additional solar may be beneficial and economic for JEA. However, before making final decisions about the amount and timing of new solar, and whether storage is appropriate, JEA should consider performing a solar integration study (such a study is beyond the scope of this IRP).
- As discussed throughout this section and supported by the evaluation results presented in Section 10 of this IRP, development of a new combined cycle for operation in 2025 appears to be cost-effective and appropriate for JEA. As such, JEA should consider the following:
    - Finalize decision on timing of Northside 3 retirement (see earlier bullets for relevant considerations).
    - Confirm whether a new combined cycle or combined cycle conversion of one or both of the existing Greenland Energy Center simple cycle units is to be pursued.
        - Develop more detailed project cost estimates for new 7HA.02 1x1 combined cycle (or similar, competing technology such as Siemens or Mitsubishi Hitachi Power Systems) and Greenland Energy Center combined cycle conversions.
        - Consider issuing a request for proposals (RFP) for comparable power supply alternatives.
        - Initiate activities to support developing and filing a determination of need, as a new combined cycle or conversion of the Greenland Energy Center simple cycle units would fall under the Florida Power Plant Siting Act (PPSA), as well as other necessary environmental permitting.
            - Development of a new power plant, expansion, repowering or conversion of an existing power plant or addition of a new solar development with 75 MW or greater of steam capacity falls under the PPSA.

Table ES-2 Summary of Potential Resource Considerations

Timeframe	Natural Gas Resources	Solid-Fuel Resources	Nuclear Resources	Renewables	EE/DSM
Short-term (2020-2029)	• Potential Northside 3 retirement in September 2025; new combined cycle or combined cycle conversion in 2025/26 timeframe.	• No retirements or additions.	• 200 MW Vogtle 20-year PPA expected (100 MW beginning 2021; 100 MW beginning 2022).	• Continue to evaluate opportunities for additional solar (with and without storage). • IRP considered utility-scale solar (with and without storage). Economics of each may be expected to improve over the next several years. • JEA has recently committed to ~ 300 MW of solar; future evaluations of additional solar should consider ability to integrate with JEA's system (i.e. solar integration analysis).	• Continue with evaluations of new EE/DSM/Direct Load Control programs as appropriate for JEA's customers.
Mid–term (2030-2039) to Long-term (2040 – 2050)	• New simple cycle and/or new combined cycle capacity, depending on load growth, fuel prices, environmental regulations, etc.	• No solid fuel additions. • No solid fuel retirements under current environmental regulations; more stringent environmental regulations may necessitate retirement considerations. • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.	• New nuclear not considered as part of this IRP; consideration of future nuclear may be appropriate as Small Modular Reactor (SMR) technology matures.	• Continue to evaluate opportunities for additional solar (with and without storage). • IRP considered utility-scale solar (with and without storage). Economics of each may be expected to improve over the next several years. • JEA has recently committed to ~ 300 MW of solar; future evaluations of additional solar should consider ability to integrate with JEA's system (i.e. solar integration analysis).	• Continue with evaluations of new EE/DSM/Direct Load Control programs as appropriate for JEA's customers.

Table ES-3 Summary of Potential Resource Considerations by Scenario

Timeframe	Baseline Scenario	Load Erosion Scenario	Increased Electrification Scenario	Green Economy Scenario
Short-term (2020-2029)	• Decision on retirement of Northside 3 • Decision on new combined cycle resource (i.e. conversion of GEC simple cycle unit(s) or new 1x1 combined cycle) • Consideration of additional utility-scale solar PV (solar integration study recommended)	• Decision on retirement of Northside 3 • Decision on new combined cycle resource (i.e. conversion of GEC simple cycle unit(s) or new 1x1 combined cycle) • Consideration of additional utility-scale solar PV (solar integration study recommended)	• Decision on retirement of Northside 3 • Decision on new combined cycle resource (i.e. conversion of GEC simple cycle unit(s) or new 1x1 combined cycle) • Consideration of additional utility-scale solar PV (solar integration study recommended)	• Decision on retirement of Northside 3 • Decision on new combined cycle resource (i.e. conversion of GEC simple cycle unit(s) or new 1x1 combined cycle) • Consideration of additional utility-scale solar PV (solar integration study recommended) • No solid fuel retirements under current environmental regulations; more stringent environmental regulations may necessitate retirement considerations
Mid–term (2030-2039) to Long-term (2040 – 2050)	• Decision on new simple cycle resources. • Consideration of additional utility-scale solar PV (solar integration study recommended) • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.	• Decision on new simple cycle resources. • Consideration of additional utility-scale solar PV (solar integration study recommended) • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.	• Decision on new simple cycle resources. • Consideration of additional utility-scale solar PV (solar integration study recommended) • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.	• Decision on new simple cycle resources. • Consideration of additional utility-scale solar PV (solar integration study recommended) • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.

1.0 INTRODUCTION

This report documents the 2019 Integrated Resource Plan (IRP) developed for JEA's electric system over the 2020 through 2050 period. The IRP was developed to assist JEA in determining the most cost-effective type of generating unit to provide firm power to JEA in the 2025 to 2030 timeframe, with consideration of potential retirement of JEA's Northside 3 as the primary driver for projected capacity requirements.

A scenario approach was utilized for the IRP, which allowed for simultaneous consideration of variations to several of the reference set of inputs (referred to herein as the Baseline Scenario). Scenarios were developed to address uncertainties related to:

- Projected load growth (both peak demand and annual energy requirements)
- Penetration of plug-in electric vehicles and increased electrification in general
- Net metering, energy efficiency, energy conservation, and direct load control
- Future environmental regulation and clean energy standards
- Estimated capital costs for new generating units
- Projected natural gas prices
- Potential future solid-fuel unit retirements

This IRP provides for a comprehensive analysis of supply-side options that are reasonable for JEA to consider in the context of satisfying projected capacity requirements in an economic, reliable, and environmentally appropriate manner across a wide range of various load forecast, load shapes, and fuel price scenarios and sensitivities. Embedded within each load forecast utilized in each scenario are various assumptions related to current and anticipated trends affecting the electric utility industry, specifically considerations related to energy efficiency and conservation, interruptible loads, net metering, and penetration of plug-in electric vehicles (PEVs). The relevant assumptions and methodologies utilized to develop the inputs considered throughout this IRP are discussed in more detail in subsequent sections of this IRP, along with results of the economic analyses and corresponding conclusions. The remainder of this IRP is structured as follows:

- Section 2.0 provides a description of JEA's existing facilities, summarizing available generating resources including wholly and jointly owned units as well as purchased power resources. Section 2.0 also discussed JEA's electric transmission and distribution systems, demand-side management programs, and clean power and renewable energy initiatives.
- Section 3.0 provides a description of the process and methodology that JEA utilized to develop the base case load forecast, including seasonal peak demand and net energy for load requirements, reflected in this IRP.
- Section 4.0 discusses JEA's projected seasonal capacity requirements, which take into account existing and planned future capacity resources, seasonal peak demand forecasts, and JEA's planning reserve margin (15 percent).
- Section 5.0 discusses the economic parameters (inflation and discount rates, interest during construction rate, and levelized fixed charge rate) used throughout this IRP.
- Section 6.0 introduces the environmental assessment that was performed as part of this IRP (the assessment is included, in its current draft form, as Appendix A to this IRP).

- Section 7.0 discusses the process and methodology used to develop the base case fuel price projections reflected in this IRP, including consideration of firm natural gas transportation requirements, and corresponding estimated costs, associated with new supply-side options.
- Section 8.0 discusses the supply-side options considered in this IRP, including natural gas and solar photovoltaic (PV) options. A more detailed discussion of the supply-side options is included as Appendix B to this IRP.
- Section 9.0 discusses the supply-side screening, or LCOE analysis, that was performed to assess the economics of the supply-side options and determine which options should be considered for more detailed evaluation.
- Section 10.0 discusses the generation expansion planning and production cost modeling performed for this IRP, including discussion of the various scenarios and sensitivities evaluated, along with corresponding economic results.
- Section 11.0 presents conclusions based on the results of the analysis presented in previous sections of this IRP.
- Appendix A presents the Environmental Assessment, in its current draft form.
- Appendix B presents the Characterization of Supply-Side Options, in its current draft form.

2.0 DESCRIPTION OF EXISTING FACILITIES

2.1 System Description

2.1.1 Power Supply System Description

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers most of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves more than 450,000 customers.

As of January 1, 2019, JEA consists of three financially separate entities: the JEA Electric System; the St Johns River Power Park bulk power system; and the Robert W. Scherer bulk power system. St Johns River Power Park is in the process of being decommissioned. The total projected net capability of JEA's generation system is 3,090 MW for winter and 2,767 MW for summer, as shown in Table 2-1.

2.1.1.1 The JEA Electric System

The JEA Electric System consists of generating facilities located on four plant sites within the City of Jacksonville (The City); the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), the Brandy Branch Generating Station (Brandy Branch), and the Greenland Energy Center (GEC).

Collectively, these plants consist of two dual-fired (petroleum coke/coal) Circulating Fluidized Bed (CFB) steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); seven dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT7 and GT8, GEC GT1 and GT2 and Brandy Branch GT1, CT2, and CT3); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle heat recovery steam generator unit (Brandy Branch steam Unit 4).

At the time this IRP was initiated, JEA was in the process of upgrading Brandy Branch units CT2 and CT3. The upgrade involves the addition of General Electric's Advanced Gas Path (AGP) and 7FA.05 compressor modifications to the existing Brandy Branch CT2 and CT3 7FA.03 units. The upgrade is expected to yield an additional 84 MW of summer capacity and 33 MW of winter capacity via efficiency improvements. The increased capacity anticipated to result from these unit upgrades is reflected in JEA's future available capacity in this IRP. [2]

[2] The upgrade to the Brandy Branch combined cycle units was completed in Spring of 2019. The upgrade of CT2 and CT3 increased Summer net output on gas from 150 MW each to 190 net MW each, or 80 net MW total. The associated steam unit (BB4) net Summer output increased from 201 to 216 net MW, for a combined Summer net unit output of 596 net MW, or a 95MW net Summer increase. The upgrade of CT2 and CT3 increased Winter net output from 186 net MW to 209 net MW each, or a 46 net MW total increase. The associated steam unit (BB4) Net Winter Output dropped from 223 MW to 216 net MW, for a combined Winter net unit output of 634 net MW, or a 39 net MW increase.

Table 2-1
JEA's Existing Generating Facilities

Plant Name	Unit No.	Unit Type	Fuel Type		In-Service Date	Capacity		
			Primary	Secondary		Nameplate (kW)	Net Summer (MW)	Net Winter (MW)
Kennedy	7	GT	NG	DFO	6/2000	203,800	150	191
Kennedy	8	GT	NG	DFO	6/2009	203,800	150	191
Northside	1	ST	PC	BIT	5/2003	350,000	293	293
Northside	2	ST	PC	BIT	4/2003	350,000	293	293
Northside	3	ST	NG	RFO	7/1977	563,700	524	524
Northside	33-36	GT	DFO	N/A	1/1975	248,400	212	246
Brandy Branch	1	GT	NG	DFO	5/2001	203,800	150	191
Brandy Branch	2	CT	NG	DFO	5/2001	203,800	150	186
Brandy Branch	3	CT	NG	DFO	10/2001	203,800	150	186
Brandy Branch	4	CA	WH	N/A	1/2005	268,400	201	223
Greenland Energy Center	1	GT	NG	DFO	6/2011	203,800	150	186
Greenland Energy Center	2	GT	NG	DFO	6/2011	203,800	150	186
Scherer	4	ST	BIT	N/A	2/1989	990,000	194	194
							2,767	3,090

Notes/Legend:
(1). Nameplate (kW) is total unit not ownership.
(2). Net capability reflects JEA's 23.64% ownership in Scherer 4.
(3). Numbers may not add due to rounding.

GT – Simple Cycle Gas Turbine
ST – Steam Turbine
CT – Combustion Turbine portion of Combined Cycle
CA – Steam Turbine portion of Combined Cycle

NG – Natural Gas
DFO – Distillate (No. 2) Fuel Oil
PC – Petroleum Coke
BIT – Bituminous Coal
RFO – Residual (No. 6) Fuel Oil
WH – Waste Heat

2.1.1.2 The Bulk Power Systems

2.1.1.2.1 St. John's River Power Park

The St. Johns River Power Park (SJRPP) was jointly owned by JEA (80 percent) and Florida Power and Light (FPL; 20 percent ownership). SJRPP consisted of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station in Jacksonville, Florida. Unit 1 began commercial operation in March 1987 and Unit 2 followed in May 1988.

Although JEA was the majority owner of SJRPP, both owners were entitled to 50 percent of the output of SJRPP. Since Florida Power and Light ownership was only 20 percent, JEA sold, and FPL purchased, on a "take-or-pay" basis, 37.5 percent of JEA's 80 percent share of the generating capacity and related energy of SJRPP. Contractually, the sale would have continued until the earlier of the Joint Ownership Agreement expiration in October 2021 or the realization of the sale limit which was expected to occur June 2019.

JEA and FPL obtained all required approvals, including those of the JEA Board, FPL's Board, and the Florida PSC, and definitive agreements for cessation of commercial operations and decommissioning of the Power Park were executed, including an Asset Transfer and Contract Termination Agreement dated as of May 17, 2017.

JEA completed the Regulated Material Study and Environmental Site Assessments on August 25, 2017. FPL obtained Florida PSC Final Order approval on October 16, 2017. JEA's Procurement Awards Committee approved a Demolition and Soil Remediation contract on November 16, 2017. The plant closure was executed on January 5, 2018. The total demolition and the soil and groundwater remediation is scheduled to be complete in mid-2020. At that time final closing will occur and all land and real assets will be transferred to JEA.

2.1.1.2.2 Robert W. Scherer Generating Station

Robert W. Scherer Unit 4 is a coal-fired generating unit with a net output of 846 MW located in Monroe County, Georgia. Scherer Unit 4 is one of four coal-fired steam units located at the 12,000-acre site near the Ocmulgee River approximately three miles east of Forsyth, Georgia. JEA and FPL purchased an undivided interest of this unit from Georgia Power Company. JEA has 23.6 percent (200 net MW) and FPL 76.36 percent ownership interest in Unit 4.

In addition to the purchase of undivided ownership interests in Scherer Unit 4, under the Scherer Unit 4 Purchase Agreement, JEA and FPL also purchased proportionate undivided ownership interests in (i) certain common facilities shared by Units 3 and 4 at Plant Scherer, (ii) certain common facilities shared by Units 1, 2, 3 and 4 at Plant Scherer and (iii) an associated coal stockpile. Under a separate agreement, JEA also purchased a proportionate undivided ownership interest in substation and switchyard facilities. JEA has firm transmission service for delivering the energy output from this unit to JEA's system.

2.1.2 Purchased Power

JEA's current purchased power resources are summarized in Table 2-2, and are discussed in more detail in the following subsections.

Table 2-2 Summary of JEA's Current Power Purchase Resources				
Contract	Start Date	End Date	MW(1)	Product Type
LES Trailridge I	12/06/08	12/31/26	9	Annual
LES Trailridge II	02/01/14	12/31/26	6	Annual
MEAG Plant Vogtle Unit 3	11/01/21	11/01/41	100	Annual
MEAG Plant Vogtle Unit 4	11/01/22	11/01/42	100	Annual
Jacksonville Solar	09/30/10	09/30/40	12	Annual
NW Jacksonville Solar	05/30/17	05/30/42	7	Annual
Old Plank Road Solar	10/13/17	10/13/37	3	Annual
Starratt Solar	12/20/17	12/20/37	5	Annual
Blair Site Solar	01/23/18	01/23/38	4	Annual
Simmons Road Solar	01/17/18	01/17/38	2	Annual
Old Kings Solar	10/15/18	10/15/38	1	Annual
Imeson Solar	10/01/19	10/01/39	5	Annual
Cecil Commerce Solar(2)	02/01/21	02/01/45	50	Annual
Forest Trail Solar (2)	05/01/21	05/01/46	50	Annual
Deep Creek Solar (2)	08/01/21	08/01/46	50	Annual
Westlake Solar(2)	10/01/21	10/01/46	50	Annual
Beaver Street Solar(2)	01/01/22	01/01/47	50	Annual
(1) Capacity level may vary over contract term. All capacities are listed in MWAC. (2) Dates are tentative.				

2.1.2.1 Trail Ridge Landfill

In 2006, JEA entered into a power purchase agreement (PPA) with Trail Ridge Energy, LLC (TRE) to purchase energy and environmental attributes from up to 9 net MW of firm renewable generation capacity utilizing the methane gas from the City's Trail Ridge landfill located in western Duval County (the Phase One Purchase). The facility is one of the largest landfill gas-to-energy facilities in the Southeast. The TRE gas-to-energy facility began commercial operation December 6, 2008.

JEA and TRE executed an amendment to this power purchase agreement on March 9, 2011 that included additional capacity. The "Phase Two Purchase" amendment included up to 9 additional net MW. Landfill Energy Systems (LES) developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began February 2015.

2.1.2.2 Southern Company

JEA entered into a power purchase agreement with Southern Power to purchase 200 MW of firm capacity and associated energy from January 1, 2018 – December 31, 2019. The purchase is unit contingent on one of 2, Southern Power owned, natural gas fired combined cycle units at the Hal B Wansley plant, Wansley Unit 7. The plant is located in northeastern Heard County between the cities of Franklin and Carrollton, Georgia.

2.1.2.3 Jacksonville Solar

In May 2009, JEA entered into a power purchase agreement with Jacksonville Solar, LLC (Jax Solar) to receive up to 12 MW_{AC} of as-available renewable energy from the solar plant located in western Duval County. The Jacksonville Solar facility consists of approximately 200,000 photovoltaic panels on a 100-acre site and was forecasted to produce an average of 22,340 megawatt-hours (MWh) of electricity per year. The Jacksonville Solar plant began commercial operation at full designed capacity September 30, 2010. Jax Solar generated 17,670 MWh in calendar year 2018.

2.1.2.4 Solar Power Purchase Agreements

In 2014, JEA's Board approved a Solar Photovoltaic Initiative that supports up to 38 additional MW_{AC}. JEA issued Solar PV RFPs in December 2014 and April 2015 to solicit PPA proposals to satisfy the adopted 2014 Solar PV Policy. JEA awarded a total of 31.5 MW of solar PV power purchase contracts with terms of 20-25 years to various vendors. Of the awarded contracts, only seven agreements have been finalized for a total of 27 MW. Only one of these solar facilities remain to be completed by close of 1st quarter of 2019.

In October 2017, the JEA Board approved a further solar expansion consisting of five-50 MWAC solar facilities to be constructed on JEA-owned property. These projects, totaling 250 MW_{AC}, are structured as PPAs. Request for Qualifications to select the vendors was issued and a vendor short list was announced in November 2017. The RFP for the facilities was released to the short listed vendors on January 2, 2018. JEA received and evaluated 50 proposals that conformed to the requirements of the RFP. April 26, 2018, JEA awarded the contracts to EDF Renewables Distributed Solutions. JEA negotiated and executed the contracts 1st quarter of 2019. JEA will purchase the produced energy and the associated environmental attributes from each facility. Beaver Street Solar Center, Cecil Commerce Solar Center, Deep Creek Solar Center, Forest Trail Solar Center, and Westlake Solar Center facilities are tentatively scheduled for completion by the end of 2022.

2.1.2.5 Nuclear Generation

JEA's Board had established targets to acquire 10 percent of JEA's energy requirements from nuclear sources by 2018 and up to 30 percent by 2030. In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships as part of a strategy for greater regulatory and fuel diversification. In October, 2017, the JEA Board modified this goal by adopting an Energy Mix Policy, which allows the 30 percent target to be met by any carbon-free or carbon-neutral generation. Meeting these targets will result in a smaller carbon footprint for JEA's customers.

In June 2008, JEA entered into a 20-year power purchase agreement (PPA) with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4. These two new nuclear units are under construction at the existing Plant Vogtle location in Burke County, GA. Under this PPA, JEA is entitled to a total of 206 MW of firm capacity from these units. After accounting for transmission losses, JEA is anticipating to receive a total of 200 MW of net firm capacity from these units. The current schedule makes available to JEA 100 net MW of capacity beginning November 2021 from Unit 3 and an additional 100 net MW beginning November 2022 from Unit 4.

2.1.2.6 Cogeneration

Cogeneration facilities help meet the energy needs of JEA's system on an as-available, non-firm basis. Since these facilities are considered energy only resources, they are not forecasted to contribute firm capacity to JEA's reserve margin requirements.

Currently, JEA has contracts with one customer-owned qualifying facility (QF), as defined in the Public Utilities Regulatory Policy Act of 1978. Anheuser Busch has a total installed summer rated capacity of 8 MW and winter rated capacity of 9 MW.

2.2 Transmission and Distribution

2.2.1 Transmission and Interconnections

JEA's transmission system consists of 744 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV.

The 500 kV transmission lines are jointly owned by JEA and FPL, completing the path from FPL's Duval substation (west of JEA's system) to the north to interconnect with the Georgia Integrated Transmission System (ITS). Along with JEA and FPL, Duke Energy Florida and the City of Tallahassee each own transmission interconnections with the Georgia ITS. JEA's import capacity is 1,228 MW over the 500 kV transmission lines through Duval substation.

The 230 kV and 138 kV transmission systems provide a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest; covering the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates a total of four 230 kV transmission interconnections at FPL's Duval substation in Duval County. In addition, JEA has one 230 kV transmission interconnection which terminates at Beaches Energy Services' Sampson substation (FPL metered) in St. Johns County. JEA's ownership of this interconnection ends at State Road 210 which is located just north of the Sampson substation. JEA also has one 230 kV transmission interconnection terminating at Seminole Electric Cooperative Incorporated's (SECI) Black Creek substation in Clay County. JEA's ownership of this interconnection ends at the Duval County – Clay County line.

JEA has one 138 kV tie-line owned by Beaches Energy Services terminating at JEA's Neptune substation. The 138 kV circuit breaker at Neptune substation is owned and maintained by JEA, and the 138 kV transmission line fed by the circuit breaker is owned and operated by Beaches Energy Services. JEA also owns and operates a 138 kV transmission loop that extends from the 138 kV backbone north to JEA's Nassau substation. This substation serves as a 138 kV transmission interconnection point for FPL's O'Neil substation and Florida Public Utilities Company's (FPU) Step Down substation. JEA's ownership of these two 138 kV interconnections end at the first transmission structure outside of the Nassau substation.

2.2.2 Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. In compliance with North American Electric Reliability Corporation (NERC) and Florida Reliability Coordinating Council's (FRCC) standards, JEA continually assesses the needs and options for increasing the capability of the transmission system.

JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC's published Regional Transmission Planning Process. FRCC's published Regional Transmission Planning Process facilitates coordinated planning by all transmission providers, owners, and stakeholders within the FRCC Region.

FRCC's members include investor owned utilities, municipal utilities, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Technical Subcommittee in conjunction with the FRCC Staff to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the Federal Energy Regulatory Commission (FERC) Final Rule in Docket No. RM05-35-000 for: (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

2.2.3 Transmission Service Requirements

JEA also engages in market transmission service obligations via the Open Access Same-time Information System (OASIS) where daily, weekly, monthly, and annual firm and non-firm transmission requests are submitted by potential transmission service subscribers.

The following two existing transmission service contracts are set to expire in the near future:

- The contract for the delivery of backup, non-firm, as-available service to Beaches Energy Services will expire at the end of November 2019.
- FPL purchased Cedar Bay plant and retired the generation in December 2016. The transmission service for the delivery of Cedar Bay generation has been converted to JEA's Open Access Transmission service, and will remain with FPL through 2024.

2.2.4 Distribution

The JEA distribution system operates at three primary voltage levels (4.16 kV, 13.2 kV, and 26.4 kV). The 4.16kV system serves a permanently defined area in older residential neighborhoods. The 13kV system serves a permanently defined area in the urban downtown area. These two distribution systems serve any new customers that are located within their defined areas, but there are no plans to expand these two systems beyond their present boundaries. The 26.4 kV system serves approximately 86 percent of JEA's load, including 75 percent of the 4.16 kV substations. The current standard is to expand the 26.4kV system as required to serve all new distribution loads, except loads that are within the boundaries of the 4.16kV or 13.2kV systems. JEA has approximately 6,600 miles of distribution circuits of which more than half is underground.

2.3 Demand-Side Management

2.3.1 Interruptible Load

JEA currently offers Interruptible and Curtailable Service to eligible industrial class customers with peak demands of 750 kW or higher. Customers who subscribe to the Interruptible Service are subject to interruption of their full nominated load during times of system emergencies, including supply shortages. Customers who subscribe to the Curtailable Service may elect to voluntarily curtail portions of their nominated load based on economic incentives. For the purposes of JEA's planning reserve requirements, only customer load nominated for Interruptible Service is treated as non-firm. This non-firm load reduces the need for capacity planning reserves to meet peak demands. JEA forecasts 105 MW of interruptible peak load for the summer and 102 MW for the winter which remain constant throughout the study period. For 2019, the interruptible load represents 3.9 percent of the forecasted total peak demand in the winter and 4.3 percent of the forecasted total peak demand in the summer.

2.3.2 Demand-Side Management Programs

JEA continues to pursue a greater implementation of demand-side management programs where economically beneficial and continues to meet JEA's Florida Energy Efficiency and Conservation Act (FEECA) goals. JEA's demand-side management programs focus on improving the efficiency of customer end uses as well as improving the system load factor. To encourage efficient customer usage, JEA offers customers both education and economic incentives on more efficient end use technologies. For load factor improvement, JEA has implemented a Demand Rate Pilot program with the intent of reducing peaks for residential customers.

Electrification programs include on-road and off-road vehicles, floor scrubbers, forklifts, cranes and other industrial process technologies. JEA's forecast of annual incremental demand and energy reductions due to its current DSM energy efficiency programs is shown in Table 2-3. The Demand Rate Pilot program is still in development, and as such impacts are not reflected in Table 2-3. JEA's current and planned DSM programs are summarized by commercial and residential programs in Table 2-4.

Table 2-3
DSM Portfolio – Energy Efficiency Programs

Annual Incremental		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Annual Energy (GWh)	Residential	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
	Commercial	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
	Total	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7	25.7
Summer Peak (MW)	Residential	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	Commercial	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
	Total	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Winter Peak (MW)	Residential	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Commercial	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	Total	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1	3.1

Table 2-4 DSM Programs	
Commercial Programs	**Residential Programs**
Commercial Energy Assessment Program	Residential Energy Assessment Program
Commercial Energy Efficient Products	Residential Energy Efficient Products
Commercial Prescriptive Program	Residential New Build
Custom Commercial Program	Residential Solar Water Heating
Commercial Solar Net Metering	Residential Solar Net Metering
Small Business Direct Install Program	Neighborhood Efficiency Program
Off-Road Electrification	Residential Efficiency Upgrade
	Electric Vehicles
	Demand Rate Pilot

2.4 Clean Power and Renewable Energy

JEA continues to investigate economic opportunities to incorporate clean power and renewable energy into JEA's power supply portfolio. To that end, JEA has implemented several clean power and renewable energy initiatives and continues to evaluate potential new initiatives.

2.4.1 Clean Power Program

From 1999 - 2014, JEA worked with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups through routine Clean Power Program meetings, as established in JEA's "Clean Power Action Plan" as a means of providing guidance and recommendations to JEA in the development and implementation of the Clean Power Programs.

Since the conclusion of this program, JEA has continued to make considerable progress related to clean power initiatives. This progress includes installation of clean power systems, unit efficiency improvements, solar power purchase agreements, legislative and public education activities, and research and development of clean power technologies.

2.4.2 Renewable Energy

In 2005, JEA received a Sierra Club Clean Power Award for its voluntary commitment to increasing the use of solar, wind and other renewable or green power sources. Since that time, JEA has implemented new renewable energy projects and continues to explore additional opportunities to increase its utilization of renewable energy. JEA issued several Requests for Proposals (RFPs) for solar energy that resulted in new resources for JEA's portfolio. As discussed below, JEA's existing renewable energy sources include installation of solar photovoltaic (PV), solar thermal, and landfill gas capacity.

2.4.2.1 Solar and the Solar Incentive

JEA has installed 35 solar PV systems, totaling 222 kW, on public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport. To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program provided rebates for the installation of solar thermal systems.

In addition to the solar thermal system incentive program, JEA established a residential net metering program to encourage the use of customer-sited solar PV systems. The policy has since evolved with several revisions:

- 2009: Tier 1 & 2 Net Metering policy launched to include all customer-owned renewable generation systems less than or equal to 100 kW
- 2011: Tier 3 Net Metering policy established for customer-owned renewable generation systems greater than 100 kW up to 2 MW
- 2014: Policy updated to define Tier 1 as 10 kW or less, Tier 2 as greater than 10 kW – 100 kW, and Tier 3 as greater than 100 kW – 2 MW. This policy was capped at 10 MW for total generation. All customer-owned generation in excess of 2 MW would be addressed in JEA's Distributed Generation Policy.
- October 2017: JEA Board approved the consolidation of the Net Metering and Distributed Generation Policies into a single, comprehensive Distributed Generation Policy.
- April 1, 2018: The comprehensive Distributed Generation (DG) Policy qualifies renewable and non-renewable customer-owned generation systems under the following ranges:
    - DG-1 – Less than or equal to 2 MW
    - DG-2D – Over 2 MW with distribution level connection
    - DG-2T – Over 2 MW with transmission level connection

  This DG policy will act in concert with the JEA Battery Incentive Program (see Section 1.4.3.3 Energy Storage) and allows existing customers the option to be grandfathered under the 2014 Net Metering Policy for a period of 20 years.

JEA signed a power purchase agreement with Jacksonville Solar, LLC in May 2009 to provide energy from a 12 MW_{AC} rated solar farm, which began operation in summer 2010 (see Section 1.1.2.3 Jacksonville Solar).

In December 2014, a Solar Policy was approved by the JEA Board, setting forth the goal of an additional 38 MW of solar photovoltaic (PV) power via power purchase contracts by the end of 2016. JEA issued three Solar PV RFPs and received a total of 73 bids. In 2015, JEA awarded a total of 31.5 MW of solar PV power purchase contracts with terms of 20 to 25 years to various vendors. One PPA for 5 MW on land owned by the U.S. Navy was awarded to Hecate Energy, LLC in 2016. This contract was canceled because JEA and the Navy were unable to reach an agreement on the lease. A 4.5 MW award to SunEdison Utility Solutions, LLC was cancelled due to failure of the contractor to secure site control. The following are the seven PPAs that were finalized for a total of 27 MW in JEA's service territory of which JEA pays only for the energy produced by the facilities and have rights to the associated environmental attributes:

- 25-year PPA with Northwest Jacksonville Solar Partners, LLC for the produced 7 MW_{AC} facility, which consists of 28,000 single-axis tracking photovoltaic panels on a vendor-leased site, owned by American Electric Power (AEP). The facility became operational on May 30, 2017.
- 20-year PPA with Old Plank Road Solar Farm, LLC for the produced 3 MW_{AC} solar farm, Old Plank Road Solar. The facility, which consists of 12,800 single-axis tracking photovoltaic panels on a vendor-leased 40-acre site, is owned by Southeast Solar Farm Fund, a partnership between PEC Velo & Cox Communications. The site attained commercial operation on October 13, 2017.
- 20-year PPA with C2 Starratt Solar, LLC for the 5 MW_{AC} solar farm, Starratt Solar. The facility, on a vendor-leased site, is owned by C2 Starratt Solar, LLC and was constructed by Inman Solar, Incorporated. The site attained commercial operation on December 20, 2017.

- 20-year PPA with Inman Solar Holdings 2, LLC for the 2 MW_{AC} solar farm, Simmons Solar. The facility, on a vendor-leased site, is owned by Inman Solar Holdings 2, LLC and was constructed by Inman Solar, Inc. The site attained commercial operation on January 17, 2018.
- 20-year PPA with Hecate Energy Blair Road, LLC for the 4 MW_{AC} solar farm, Blair Road. The facility, on a vendor-leased site, is owned by Hecate Energy Blair Road, LLC and was constructed by Hecate Energy, LLC. The site attained commercial operation on January 23, 2018.
- 20-year PPA with JAX Solar Developers, a wholly-owned subsidiary of Mirasol Fafco Solar, Inc. for the 1 MW_{AC} solar farm, Old Kings Rd Solar. The facility is owned by EcoPower Development, LLC and was constructed by Mirasol Fafco Solar, Inc. The site attained commercial operation on October 15, 2018.
- 20-year PPA with National Solar, LLC for a 5 MW_{AC} solar PV and 4 MWh battery storage system. The site, labeled Imeson Solar, is scheduled for commercial operation 4th quarter 2019[3].

In October 2017, the JEA Board approved a further solar expansion consisting of five-50 MW_{AC} solar facilities to be constructed on JEA-owned property. These projects, totaling 250 MW_{AC}, are structured as PPAs. Request for Qualifications to select the vendors was issued and a vendor short list was announced in November 2017. The RFP for the facilities was released to the short listed vendors on January 2, 2018. JEA received and evaluated 50 proposals that conformed to the requirements of the RFP. Near the end of April 2018, JEA awarded the contracts to EDF Renewables Distributed Solutions. JEA and EDF executed the contracts during the 1st quarter of 2019. JEA will purchase the produced energy, as well as the associated environmental attributes from each facility: Beaver Street Solar Center, Cecil Commerce Solar Center, Deep Creek Solar Center, Forest Trail Solar Center, and Westlake Solar Center. The facilities are tentatively scheduled for completion as described in Table 2-2.

2.4.2.2 Landfill Gas and Biogas

JEA owned three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997, and has been fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, gas generation has declined and one generator was removed and placed into service at the Buckman Wastewater Treatment facility and Girvin was decommissioned in 2014.

The JEA's Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The current facility manages the sludge using three anaerobic digesters and one sludge dryer to produce a pelletized fertilizer product. The methane gas from the digesters can be used as a fuel for the sludge dryer and for the on-site 800 kW generator.

JEA signed a Power Purchase Agreement with Trail Ridge Energy, LLC (TRE) in 2006 (Phase One) for 9 net MW of the gas-to-energy facility at the Trail Ridge Landfill in Duval County. In 2011, JEA executed an amendment to the Power Purchase Agreement (Phase Two) to purchase an additional 9 MW from a gas-to-energy facility. LES has developed the Sarasota County Landfill in Nokomis, Florida (up to 6 net MW) to serve part of this Phase Two agreement. This portion of the Phase Two purchase began February 2015 (see Section 2.1.2.1 Trail Ridge Landfill).

[3] Imeson Solar, also known as Sunport, achieved commercial operation December 2019.

2.4.2.3 Wind

As part of its ongoing effort to utilize more sources of renewable energy, in 2004 JEA entered into a 20-year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits (green tags) associated with this green power project. Under the wind generation agreement, JEA purchases 10 MW of capacity from NPPD's wind generation facility. In turn, NPPD buys back the energy at specified on and off peak charges.

JEA has sold environmental credits for specified periods from this project thereby reducing but not eliminating JEA's net cost for this resource for that period. With the expansion of JEA's renewable portfolio within the State of Florida, additional landfill gas generation and new solar facilities, JEA and NPPD agreed to terminate the contract effective December 31, 2019.

2.4.2.4 Biomass

In 2008, to obtain cost-effective biomass generation, JEA completed a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in Northside 1 and 2. The JEA self-build projects would not have been eligible for the federal tax credits afforded to developers. The co-firing alternative for Northside 1 and 2 considered potential reliability issues associated with both of those units. Even though the price of petroleum coke has been volatile in recent past, petroleum coke prices are still forecasted to be lower than the cost of biomass on an as-fired basis. In addition, JEA conducted an analytical evaluation of specific biomass fuel types to determine the possibility of conducting a co-firing test in Northside 1 or 2.

In 2011, JEA co-fired biomass in the Northside Units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. Northside 1 and 2 produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. At that time, JEA received bids from local sources to provide sized biomass for potential use for Northside Units 1 and 2. Currently, no biomass is being co-fired in Northside Units 1 and 2.

2.4.3 Research Efforts

Many of Florida's renewable resources such as offshore wind, tidal, and energy crops require additional research and development before they can be implemented as large-scale power generating technologies. JEA's renewable energy research efforts have focused on the development of these technologies through a partnership with the University of North Florida's (UNF) Engineering Department. In the past, UNF and JEA have worked on the following projects:

- JEA with UNF, worked to quantify the winter peak reductions of solar hot water systems.
- UNF, in association with the University of Florida, evaluated the effect of biodiesel fuel in a utility-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF evaluated the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway, where small proto-type turbines have been tested.
- JEA, UNF, and other Florida municipal utilities partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for offshore wind development in Florida.
- JEA provided solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.

- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.

Through Florida State University (FSU), JEA participated in The Sunshine State Solar Grid Initiative (SUNGRIN) which was a five-year project (2010-2015) funded under the DOE Solar Energy Technologies Program (SETP), Systems Integration (SI) Subprogram, High Penetration Solar Deployment Projects. The goal of the SUNGRIN project, which started in spring 2010, was to gain significant insight into effects of high-penetration levels of solar PV systems in the power grid, through simulation-assisted research and development involving a technically varied and geographically dispersed set of real-world test cases within the Florida grid. JEA provided FSU with data from the output of Jacksonville Solar project.

In addition to these projects, in 2016 JEA pledged its support to the proposed 3-year Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) project. The program, as led by Nhu Energy, Inc. and Florida Municipal Electric Association (FMEA), with partial funding from the DOE, seeks to grow solar capacity in FMEA member utilities to over 10% by 2024, and provide increased value in terms of cost of service, electric infrastructure reliability, security, and resilience, and environmental and broader economic benefits. With assistance from the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL), studies on cost and performance of solar and solar plus storage applications were conducted. As the program enters its final year, JEA is identifying potential strategies to apply study results in our solar and storage efforts.

2.4.3.1 Generation Efficiency and New Natural Gas Generation

In the late 1990's, JEA began to modernize its natural gas/oil fleet of generating units by replacing inefficient steam units and inefficient combustion turbine units with more efficient natural gas fired combustion turbines and combined cycle units. The retirement of units and their replacement with an efficient combined cycle unit and efficient simple cycle combustion turbines at Brandy Branch, Kennedy, and Greenland Energy Center significantly reduced CO_2 emissions.

2.4.3.2 Renewable Energy Credits

JEA makes all environmental attributes from renewable facilities available to sell in order to lower rates for JEA customers. JEA has sold environmental credits for specified periods. In 2019, JEA will certify approximately 20,000 Solar RECs under the Green-e certification structure and track and deliver approximately 46,000 landfill gas renewable energy credits (REC) through the North America Renewables (NAR) registry. All RECs sold to outside entities and through JEA customer programs, SolarSmart and future SolarMax, are retired and no longer considered renewable for JEA use. SolarSmart and SolarMax are customer programs that allow JEA customers to subscribe to a percentage of their load to be supplied by solar at a defined averaged solar PPA rate.

2.4.3.3 Energy Storage

JEA continues its efforts to demonstrate its commitment to energy efficiency and environmental improvement by researching energy storage applications and methods to efficiently incorporate storage technologies into the JEA system.

JEA will welcome a 4 MWh battery storage system to the grid 4th quarter 2019. The system will firm and smooth the PV output of the 5 MW_{AC} Imeson Solar PV project. This will be the first utility scale storage system of its kind on the JEA system.

JEA commenced its Battery Incentive Program April 1, 2018 to provide a financial incentive towards the cost of an energy storage system, subject to lawfully appropriated funds. The Program, meant to be used in concert with the 2018 Distributed Generation Policy, facilitates customers in being efficient energy users. Customers who elect to collect the rebate will be able to offset electricity consumption from JEA, up to the limits of their storage devices. Funds allotted to each customer under the Program is subject to review and change, to optimize adoption. Since its inception, more than 25 applications have been submitted for residential storage systems.

3.0 LOAD FORECAST

Annually, JEA develops forecasts of seasonal peaks demand, net energy for load (NEL), interruptible customer demand, demand-side management (DSM), and the impact of plug-in electric vehicles (PEVs). JEA removes from the total load forecast all seasonal, coincidental non-firm sources and adds sources of additional demand to derive a firm load forecast.

JEA uses National Oceanic and Atmospheric Administration (NOAA) Weather Station - Jacksonville International Airport for the weather parameters, Moody's Analytics (Moody) economic parameters for Duval County, JEA's Data Warehouse to determine the total number of Residential accounts and CBRE Jacksonville for Commercial and Industrial total inventory square footages. JEA develops its annual forecast using SAS and Microsoft Office Excel.

JEA's Fiscal Year 2019 baseline forecast uses 10-years of historical data. Using the shorter periods allows JEA to capture the more recent trends in customer behavior, energy efficiency and conservation, where these trends are captured in the actual data and used to forecast projections.

The following subsections discuss the methodology used by JEA to develop its peak demand and energy forecasts; the resulting annual peak demands and net energy for load requirements used for the base case load forecast in this IRP are presented in Table 3-1 at the end of this Section.

3.1 Peak Demand Forecast

JEA normalizes historical seasonal peaks using historical maximum and minimum temperatures, 24°F is used as the normal temperature for the winter peak and 97°F for the normal summer peak demands. JEA develops the seasonal peak forecasts using multiple regression analysis of normalized historical seasonal peaks, normalized historical and forecasted residential, commercial and industrial energy for Winter/Summer peak months, heating degrees for the 72 hours leading to winter peak and cooling degrees for the 48 hours leading to summer peak.

3.2 Energy Forecast

JEA begins this forecast process by weather normalizing energy for each customer class. JEA uses NOAA Weather Station - Jacksonville International Airport for historical weather data. JEA develops the normal weather using 10-year historical average heating/cooling degree days and maximum/minimum temperatures. Normal months, with heating/cooling degree days and maximum/minimum temperatures that are closest to the averages, are then selected. JEA updates its normal weather every 5 years or more frequently, if needed.

The residential energy forecast was developed using multiple regression analysis of weather normalized historical residential energy, Total Population, Median Household Income, Total Housing Starts from Moody's Analytics, JEA's total residential accounts and JEA's residential electric rate.

The commercial energy forecast was developed using multiple regression analysis of weather normalized historical commercial energy, commercial inventory square footage, total commercial employment, gross product and JEA's commercial electric rate.

The industrial energy forecast was developed using multiple regression analysis of weather normalized historical industrial energy, total industrial employment, proprietors' profit and total retail sales product for existing industrial accounts. JEA then layers in the estimated energy for new industrial customers on the forecasted industrial energy.

The lighting energy forecast was developed using the historical actual energy, number of luminaries and JEA's estimated High Pressure Sodium (HPS) to Light-Emitting Diode (LED) street light conversion schedule. The LEDs are estimated to use 45% less energy than the HPS street lights. JEA developed the forecasted number of luminaries using regression analysis of the number of JEA customers. The forecasted lighting energy was calculated using the forecasted number of luminaries, applied with the remaining HPS to LED street light conversions with all new street light additions as LED only.

3.3 Plug-in Electric Vehicle Peak Demand and Energy

The PEVs demand and energy forecasts are developed using the historical number of PEVs in Duval County obtained from Florida Department of Highway Safety and Motor Vehicles (DHSMV) and the historical number of vehicles in Duval County from the U.S. Census Bureau.

JEA forecasted the numbers of vehicles in Duval County using multiple regression analysis of historical and forecasted Duval Population, Median Household Income and Number of Households from Moody's Analytics. The forecasted number of PEVs is modeled using multiple regression analysis of the number of vehicles and the average motor gasoline price from the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO)

The usable battery capacity (70% of battery capacity) per vehicle was determined based on the current plug-in vehicle models in Duval County, such as BMW, General Motors' Chevrolet and Cadillac, Honda, Fisker, Ford, Mitsubishi, Nissan, Porsche, Tesla, Toyota and Volvo. The average usable battery capacity per PEV is calculated using the average usable battery capacity of each vehicle brand and then assumes the annual growth of usable battery capacity per PEV by using historical 5 years average growth of 0.69 kWh. Similarly, the peak capacity is determined based on the average on-board charging rate of each vehicle brand and the forecast peak capacity per PEV grows by 0.28 kW per year.

JEA developed the PEVs daily charge pattern based on the U.S. Census 2013 American Community Survey (ACS-13) for time of arrival to work and travel time to work for Duval County. The baseline forecast assumed that charging will be once every two days and uncontrolled; charging starts immediately upon arriving home.

The PEVs peak demand forecast is developed using the on-board charge rate for each model, the PEVs daily charge pattern and the total number of PEVs each year. The PEV energy forecast is developed simply by summing the hourly peak demand for each year.

Table 3-1 Base Case Peak Demand and Net Energy for Load Forecasts			
Calendar Year	Winter Peak Demand (MW)	Summer Peak Demand (MW)	Net Energy for Load (GWh)
2019	2,715	2,555	12,695
2020	2,736	2,566	12,764
2021	2,752	2,576	12,831
2022	2,769	2,587	12,906
2023	2,787	2,599	12,981
2024	2,802	2,609	13,047
2025	2,817	2,617	13,120
2026	2,832	2,627	13,199
2027	2,849	2,637	13,282
2028	2,869	2,647	13,366
2029	2,889	2,658	13,445
2030	2,906	2,668	13,522
2031	2,925	2,679	13,603
2032	2,944	2,691	13,690
2033	2,964	2,704	13,786
2034	2,988	2,719	13,894
2035	3,013	2,736	14,011
2036	3,040	2,753	14,136
2037	3,069	2,771	14,270
2038	3,100	2,792	14,413
2039	3,133	2,813	14,566
2040	3,167	2,836	14,729
2041	3,203	2,860	14,899
2042	3,242	2,885	15,076
2043	3,280	2,911	15,263
2044	3,323	2,939	15,458
2045	3,366	2,969	15,668
2046	3,411	3,001	15,889
2047	3,461	3,034	16,097
2048	3,497	3,063	16,256
2049	3,532	3,094	16,415
2050	3,569	3,133	16,576

4.0 PROJECTED CAPACITY REQUIREMENTS

JEA's electric generating resource planning practices include planning for adequate capacity resources to meet its peak demand while maintaining additional capacity (i.e., a reserve margin) to be prepared in case peak demands exceed projections and/or generating resources are unexpectedly not available. JEA evaluates future supply capacity needs for the electric system based on peak demand and energy forecasts, existing supply resources and contracts, transmission considerations, existing unit capacity changes, and future committed resources as well as other planning assumptions.

JEA's Planning Reserve Policy defines the planning reserve requirements that are used to develop the resource portfolio through the Integrated Resource Planning process. These guidelines set forth the planning criteria relative to the planning reserve levels and the constraints of the resource portfolio. JEA's system capacity is planned with a targeted 15 percent generation reserve level for forecasted wholesale and retail firm customer coincident one-hour peak demand, for both winter and summer seasons. This reserve level has been determined to be adequate to meet and exceed the industry standard Loss of Load Probability of 0.1 days per year. Further, this level has been used by the Florida Public Service Commission (FPSC) for municipalities in the consideration of need for additional generation.

To meet these Planning Reserve Policy requirements, JEA will acquire the needed capacity and associated energy as identified in Table 4, for those years where the reserve margin is below 15 percent. JEA's Planning Reserve Policy establishes a guideline that provides an allowance to meet the 15 percent reserve margin with up to 3 percent of forecasted firm peak demand in any season from purchases acquired in the operating horizon. Where JEA's seasonal needs are greater than 3% of firm peak demand, The Energy Authority (TEA) will acquire short-term, seasonal market purchases for JEA no later than the season prior to the need. TEA actively trades energy with a large number of counterparties throughout the United States, and is generally able to acquire capacity and energy from other market participants when any of its members require additional resources.

Given the planning process and criteria outlined above, projected capacity requirements for the Baseline Scenario (with the base case load forecast) considered in this IRP are shown in Table 4-1 (winter) and Table 4-2 (summer). JEA's expected capacity plan includes the addition of the purchased power agreement with MEAG for 200 MW of nuclear from the Vogtle PPA for a 20-year period (100 MW beginning in 2021, followed by another 100 MW beginning in 2022), the purchased power agreement with Southern Power for combined cycle energy and capacity from Wansley (which expires on December 31, 2019), and the previously discussed upgrades to the Brandy Branch combustion turbine units. As shown in Tables 4-1 and 4-2, JEA anticipates near-term seasonal capacity requirements in 2020 through 2022, which JEA expects to be met utilizing short-term, seasonal market purchases via TEA. Capacity requirements are anticipated to again materialize beginning in the 2025/26 timeframe (depending on the timing of retirement of Northside 3), and those capacity requirements are used in the analyses performed as part of, and discussed throughout, this IRP[4].

[4] Retirement of Northside 3 is assumed to occur in September 2025, allowing the unit to be operational and provide capacity to meet JEA's projected summer 2025 peak demand. Capacity requirements may materialize prior to JEA's winter 2025/26 peak period, and the timing of new capacity would need to be coordinated to meet JEA's peak demand plus reserve margin requirements. Seasonal peak demands are used as the basis for illustrating projected capacity requirements. The date at which new capacity would need to be added by JEA subsequent to retirement of Northside 3 is therefore indicative and for discussion purposes referred to as the 2025/26 timeframe.

Table 4-1 Winter Projected Capacity Requirements – Baseline Scenario/Base Case Load Forecast				
Calendar Year	Net Firm Winter Peak Demand (MW)	Net Firm Winter Peak Demand + 15% Reserve Margin (MW)	System Capacity, Including Unit Upgrades, Firm Purchases, and Unit Retirements (MW)	Excess/(Deficit) Capacity to Maintain 15% Reserve Margin (MW)
2020	2,736	3,146	3,162	16
2021	2,752	3,165	3,162	(2)
2022	2,769	3,184	3,262	78
2023	2,787	3,205	3,362	157
2024	2,802	3,222	3,362	140
2025	2,817	3,239	3,362	123
2026	2,832	3,256	2,838	(418)
2027	2,849	3,276	2,823	(453)
2028	2,869	3,299	2,823	(476)
2029	2,889	3,322	2,823	(499)
2030	2,906	3,342	2,823	(519)
2031	2,925	3,363	2,823	(540)
2032	2,944	3,386	2,823	(562)
2033	2,964	3,409	2,823	(586)
2034	2,988	3,436	2,823	(612)
2035	3,013	3,465	2,823	(641)
2036	3,040	3,496	2,823	(673)
2037	3,069	3,530	2,823	(706)
2038	3,100	3,566	2,823	(742)
2039	3,133	3,603	2,823	(779)
2040	3,167	3,642	2,823	(819)
2041	3,203	3,684	2,823	(861)
2042	3,242	3,728	2,723	(1,005)
2043	3,280	3,772	2,623	(1,149)
2044	3,323	3,821	2,623	(1,198)
2045	3,366	3,871	2,623	(1,248)
2046	3,411	3,923	2,623	(1,300)
2047	3,461	3,980	2,623	(1,357)
2048	3,497	4,021	2,623	(1,398)
2049	3,532	4,061	2,623	(1,438)
2050	3,569	4,104	2,623	(1,481)
Note: Northside 3 is assumed to retire in September 2025, and therefore is reflected as reduction to "System Capacity, Including Unit Upgrades, Firm Purchases, and Unit Retirements (MW)" beginning in winter 2026.				

Table 4-2
Summer Projected Capacity Requirements – Baseline Scenario/Base Case Load Forecast

Calendar Year	Net Firm Summer Peak Demand (MW)	Net Firm Summer Peak Demand + 15% Reserve Margin (MW)	System Capacity, Including Unit Upgrades, Firm Purchases, and Unit Retirements (MW)	Excess/(Deficit) Capacity to Maintain 15% Reserve Margin (MW)
2020	2,566	2,951	2,865	(86)
2021	2,576	2,963	2,865	(98)
2022	2,587	2,976	2,965	(10)
2023	2,599	2,988	3,065	77
2024	2,609	3,000	3,065	65
2025	2,617	3,010	3,065	55
2026	2,627	3,022	2,541	(480)
2027	2,637	3,032	2,526	(506)
2028	2,647	3,044	2,526	(518)
2029	2,658	3,056	2,526	(530)
2030	2,668	3,068	2,526	(542)
2031	2,679	3,081	2,526	(555)
2032	2,691	3,095	2,526	(569)
2033	2,704	3,110	2,526	(584)
2034	2,719	3,127	2,526	(601)
2035	2,736	3,146	2,526	(620)
2036	2,753	3,166	2,526	(640)
2037	2,771	3,187	2,526	(661)
2038	2,792	3,211	2,526	(685)
2039	2,813	3,235	2,526	(709)
2040	2,836	3,261	2,526	(735)
2041	2,860	3,289	2,526	(763)
2042	2,885	3,318	2,426	(892)
2043	2,911	3,348	2,326	(1,022)
2044	2,939	3,380	2,326	(1,054)
2045	2,969	3,414	2,326	(1,088)
2046	3,001	3,451	2,326	(1,125)
2047	3,034	3,489	2,326	(1,163)
2048	3,063	3,523	2,326	(1,197)
2049	3,094	3,558	2,326	(1,232)
2050	3,133	3,603	2,326	(1,277)

Note: Northside 3 is assumed to retire in September 2025, and therefore is reflected as reduction to "System Capacity, Including Unit Upgrades, Firm Purchases, and Unit Retirements (MW)" beginning in summer 2026.

5.0 ECONOMIC PARAMETERS

This section presents the economic evaluation criteria and methodology used for the Baseline Scenario evaluated in this IRP. The criteria listed below were supplied by JEA for the Baseline Scenario, and are typical of values that JEA has historically used for IRP work and other studies.

5.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed operations and maintenance (O&M) escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.0 percent.

5.2 Municipal Bond Interest Rate

The tax exempt municipal bond interest rate is assumed to be 4.5 percent.

5.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax exempt municipal bond interest rate of 4.5 percent.

5.4 Interest During Construction Rate

The interest during construction rate, or IDC, is assumed to be 4.5 percent.

5.5 Levelized Fixed Charge Rate

The levelized fixed charge rate, or FCR, represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year FCR.

Different generating technologies are assumed to have different economic lives and, therefore, different financing terms. Simple cycle combustion turbine and renewable energy (specifically, solar PV) alternatives are assumed to have a 20 year financing term, while combined cycle alternatives are assumed to be financed over 25 years. Given the various economic lives and corresponding financing terms, different levelized FCRs were developed.

For the conventional generating unit alternatives, all levelized FCR calculations assume the 4.5 percent tax exempt municipal bond interest rate, a 1.0 percent bond issuance fee, and an assumed 0.50 percent annual property insurance cost. The resulting 20 year FCR is 8.265 percent, and the resulting 25 year FCR is 7.312 percent.

For purposes of this IRP, it has been assumed that solar photovoltaic (PV) alternatives would qualify for an investment tax credit (ITC) equivalent to 30 percent of the total installed capital cost of each renewable alternative. As a tax-exempt municipal utility, JEA would not receive this ITC if JEA were to own the PV facilities, and therefore the economic analyses of solar PV assumed that JEA would enter into power purchase agreements with a developer able to capitalize on the ITC. The economic analyses assume a capital recovery factor of 12 percent for a 25-year term, and the capital cost of the PV alternatives reflect a 30 percent reduction to account for the ITCs.

6.0 ENVIROMENTAL ASSESSMENT

JEA's generation fleet is subject to numerous environmental regulatory programs and requirements. While most of the environmental regulatory programs and requirements applicable to JEA generating units have already been addressed, a few recently proposed and finalized programs in various stages of administrative transition and judicial review could have impacts on future operations. As part of this IRP, JEA commissioned an assessment of the applicability of air, water and waste programs and permitting requirements, as well as the associated potential compliance risks associated with continued operation of JEA's existing fossil fuel-fired generating units. This environmental assessment, in its current draft form, is included as Appendix A to this IRP.

7.0 FUEL PRICE PROJECTIONS

This section discusses the methodology used to develop the natural gas, solid fuel (coal and petroleum coke), and fuel oil price projections, as well as the resulting price projections, utilized in this IRP.

7.1 Natural Gas Price Projections

The Greenland Energy Center (GEC) receives natural gas via the SeaCoast Gas Transmission, LLC (SeaCoast) intrastate pipeline owned by Peoples Gas System (PGS) via the GEC Lateral, which is the distribution lateral that is owned by JEA. JEA and PGS are joint owners of a portion of the natural gas pipeline network in the Jacksonville area, including the pipelines that serve the Northside Generating Station and the Brandy Branch Generating Station. PGS owns the pipeline system that serves the Kennedy Generating Station.

The baseline natural gas price projections utilized in this IRP were developed based on the following components:

- Natural gas contract settlement prices from the New York Mercantile Exchange (NYMEX) for the Henry Hub (using NYMEX projections available on August 23, 2018).
- Henry Hub price projections included in the United States Energy Information Administration (EIA) Annual Energy Outlook 2018 (AEO2018).
- Costs for interstate transportation (representative of the historical differential between natural gas prices at the Henry Hub and at the Jacksonville City Gate).
- Natural gas transportation system losses for units located at GEC.
- Costs for PGS distribution for units located at all sites other than GEC.
- Firm natural gas transportation costs for reservation of firm natural gas in excess of JEA's existing firm natural gas transportation, both at GEC (via SeaCoast and the GEC Lateral) as well as at a potential new site considered for future generating units (referred to in this IRP as the North Jacksonville site, which is assumed to be served by a new gas pipeline to the site).

The following subsections provide additional details on each of the components of the natural gas price projections, and also present the resulting baseline natural gas prices used in this IRP. In addition to the baseline natural gas price projections, sensitivities reflecting high and low natural gas price projections have been considered in this IRP (see Section 10.0 for discussion of the natural gas price sensitivities).

7.1.1 NYMEX Henry Hub Natural Gas Price Projections

In order to develop the Henry Hub price projections that have been used as the basis of the natural gas price projections utilized in this IRP, JEA provided natural gas contract settlement prices from the New York Mercantile Exchange (NYMEX) for calendar years 2019, 2020, and 2021 for the Henry Hub (using NYMEX projections available on August 23, 2018). The NYMEX monthly prices for each of these years was averaged, on an annual basis, to develop the average annual price projections for calendar years 2019 through 2021 as shown in Table 7-1 below. Beyond 2021, Henry Hub price projections were developed by escalating the 2021 price projection at the annual escalation rates included in the United States Energy Information Administration (EIA) Annual Energy Outlook 2018 (AEO2018) Reference Case.

Table 7-1 NYMEX Henry Hub Natural Gas Price Projections (2018 $/MMBtu)	
2019	$2.84
2020	$2.66
2021	$2.59

7.1.2 AEO2018 Henry Hub Natural Gas Price Projections

The AEO2018 provides modeled projections of, among other information, energy supply, demand, and prices (including natural gas prices for the Henry Hub) through the year 2050. The projections included in the AEO2018 were developed by the EIA using the National Energy Modeling System (NEMS), an integrated model that captures interactions of economic changes and energy supply, demand, and prices. The AEO2018 can be found at: https://www.eia.gov/outlooks/archive/aeo18/.

As stated in the AEO 2018:

> EIA's Annual Energy Outlook provides modeled projections of domestic energy markets through 2050, and it includes cases with different assumptions regarding macroeconomic growth, world oil prices, technological progress, and energy policies. Strong domestic production coupled with relatively flat energy demand allows the United States to become a net energy exporter over the projection period in most cases. In the Reference case, natural gas consumption grows the most on an absolute basis, and nonhydroelectric renewables grow the most on a percentage basis.

The AEO2018 Reference Case Henry Hub price projections, and corresponding annual escalation rates, are presented in Table 7-2 below. As stated previously, the annual escalation rates presented in the AEO2018 Reference Case projections of natural gas prices at the Henry Hub have been used to escalate the 2021 NYMEX-based Henry Hub natural gas price projections. Also presented in Table 7-2 are the resulting Henry Hub natural gas price projections developed by escalating the 2021 NYMEX-based Henry Hub price projections at the annual escalation rates per the AEO2018 Reference Case.

Table 7-2 Henry Hub Natural Gas Price Projections			
Year	AEO2018 Henry Hub Natural Gas Price Projection (2017 $/MMBtu)	Annual Escalation Rate per AEO2018 Henry Hub Natural Gas Price Projections	Resulting NYMEX-based Henry Hub Natural Gas Price Projections (2018 $/MMBtu)
2021	$3.66	--	$2.59
2022	$3.69	1.03%	$2.62
2023	$3.83	3.67%	$2.71
2024	$3.94	2.97%	$2.79
2025	$4.07	3.33%	$2.89
2026	$4.12	1.05%	$2.92
2027	$4.17	1.30%	$2.95
2028	$4.19	0.45%	$2.97
2029	$4.26	1.63%	$3.02
2030	$4.26	0.10%	$3.02
2031	$4.27	0.08%	$3.02
2032	$4.27	0.22%	$3.03
2033	$4.27	-0.14%	$3.02
2034	$4.27	-0.01%	$3.02
2035	$4.26	-0.28%	$3.02
2036	$4.35	2.18%	$3.08
2037	$4.36	0.30%	$3.09
2038	$4.43	1.51%	$3.14
2039	$4.47	1.05%	$3.17
2040	$4.50	0.53%	$3.19
2041	$4.53	0.62%	$3.21
2042	$4.58	1.19%	$3.24
2043	$4.62	0.79%	$3.27
2044	$4.67	1.10%	$3.31
2045	$4.71	0.88%	$3.34
2046	$4.75	0.90%	$3.37
2047	$4.79	0.93%	$3.40
2048	$4.87	1.67%	$3.45
2049	$4.94	1.26%	$3.50
2050	$5.01	1.59%	$3.55

7.1.3 Costs for Interstate Natural Gas Transportation

JEA provided historical pricing information for natural gas delivered to Jacksonville on the Florida Gas Transmission (FGT) system as compared to the Henry Hub natural gas prices. Based on this information, JEA indicated that using $0.30/MMBtu, in 2018 dollars, was a reasonable representation of the interstate transportation cost to be included as an adder to the previously discussed NYMEX-based Henry Hub natural gas price projections presented in the last column of Table 7-2. Resulting projections of natural gas prices at the Jacksonville City Gate are presented in Table 7-3; price projections are presented in both real 2018 dollars as well as nominal dollars (using the 2.0 percent annual inflation rate discussed in Section 5.0 of this IRP).

Table 7-3
Henry Hub and Jacksonville City Gate Natural Gas Price Projections

Year	NYMEX-based Henry Hub Natural Gas Price Projections (2018 $/MMBtu)	Interstate Natural Gas Price Differential (2018 $/MMBtu)	Natural Gas Price Projections at Jacksonville City Gate (2018 $/MMBtu)	Natural Gas Price Projections at Jacksonville City Gate (Nominal $/MMBtu)
2021	$2.59	$0.30	$2.89	$3.07
2022	$2.62	$0.30	$2.92	$3.16
2023	$2.71	$0.30	$3.01	$3.33
2024	$2.79	$0.30	$3.09	$3.48
2025	$2.89	$0.30	$3.19	$3.66
2026	$2.92	$0.30	$3.22	$3.77
2027	$2.95	$0.30	$3.25	$3.89
2028	$2.97	$0.30	$3.27	$3.98
2029	$3.02	$0.30	$3.32	$4.12
2030	$3.02	$0.30	$3.32	$4.21
2031	$3.02	$0.30	$3.32	$4.30
2032	$3.03	$0.30	$3.33	$4.39
2033	$3.02	$0.30	$3.32	$4.47
2034	$3.02	$0.30	$3.32	$4.56
2035	$3.02	$0.30	$3.32	$4.64
2036	$3.08	$0.30	$3.38	$4.83
2037	$3.09	$0.30	$3.39	$4.94
2038	$3.14	$0.30	$3.44	$5.11
2039	$3.17	$0.30	$3.47	$5.26
2040	$3.19	$0.30	$3.49	$5.39
2041	$3.21	$0.30	$3.51	$5.53
2042	$3.24	$0.30	$3.54	$5.70
2043	$3.27	$0.30	$3.57	$5.86
2044	$3.31	$0.30	$3.61	$6.03
2045	$3.34	$0.30	$3.64	$6.20
2046	$3.37	$0.30	$3.67	$6.38
2047	$3.40	$0.30	$3.70	$6.56
2048	$3.45	$0.30	$3.75	$6.80
2049	$3.50	$0.30	$3.80	$7.01
2050	$3.55	$0.30	$3.85	$7.26

7.1.4 Natural Gas Transportation System Losses

For units located at GEC, the natural gas price projections presented in the last column of Table 7-3 have been increased by 1.0 percent to account for losses associated with delivery from SeaCoast via the GEC lateral.

7.1.5 Distribution Costs for Peoples Gas Transportation System

JEA provided historical information related to distribution charges for natural gas delivered via the PGS system to Northside, Kennedy, and Brandy Branch Generating Stations. The historical distribution charge of approximately $0.10/MMBtu has been incorporated into the natural gas price projections for generating units at all sites except GEC.

7.1.6 Resulting Natural Gas Price Projections for Generating Units at GEC and Other Sites

Natural gas price projections for generating units at GEC and for generating units at all other sites, reflecting each of the previously discussed components, are presented in Table 7-4.

Table 7-4 Delivered Natural Gas Price Projections		
Year	GEC Natural Gas Price Projection (Nominal $/MMBtu)	All Other Sites Natural Gas Price Projections (Nominal $/MMBtu)
2021	$3.10	$3.17
2022	$3.19	$3.26
2023	$3.36	$3.43
2024	$3.52	$3.59
2025	$3.70	$3.76
2026	$3.81	$3.87
2027	$3.93	$3.99
2028	$4.02	$4.09
2029	$4.16	$4.23
2030	$4.25	$4.31
2031	$4.34	$4.40
2032	$4.44	$4.49
2033	$4.52	$4.58
2034	$4.61	$4.67
2035	$4.69	$4.74
2036	$4.88	$4.93
2037	$4.99	$5.04
2038	$5.16	$5.21
2039	$5.31	$5.36
2040	$5.44	$5.49
2041	$5.58	$5.63
2042	$5.76	$5.80
2043	$5.92	$5.96
2044	$6.09	$6.14
2045	$6.27	$6.31
2046	$6.45	$6.48
2047	$6.63	$6.67
2048	$6.87	$6.90
2049	$7.09	$7.12
2050	$7.33	$7.36

7.1.7 Firm Natural Gas Transportation Costs

Due to electrical transmission considerations, for the IRP it has been assumed that GEC can accommodate either a 1x1 combined cycle conversion using one of the existing simple cycle units, or a 2x1 combined cycle conversion using both of the existing simple cycle units, as well as either a new 1x1 7FA.05 combined cycle, or a new 1x1 7HA.02 combined cycle.[5] Rather than performing transmission upgrades, following addition of allowable units at GEC, subsequent new units are assumed to be located at the North Jacksonville site. The following subsections discuss how costs associated with firm natural gas transportation were developed for this IRP.

7.1.7.1 Determination of Natural Gas Capacity Requirements

Based on historical firm interstate gas transportation use, for the IRP it has been assumed that firm interstate natural gas transportation capacity reservations adequate to supply 85 percent of the maximum hourly gas requirements will be required for any combined cycle. The remaining 15 percent will be supplied via interruptible natural gas supplies. Firm gas transportation capacity requirements will be calculated as follows:

- Calculate full-load gas flow rate using full-load output at net plant heat rate of the unit (at average ambient conditions, with duct firing, and reflecting non-recoverable degradation).
- Calculate daily firm natural gas transportation capacity quantity that would need to be reserved such that 4.2 percent of the total daily quantity is adequate for full-load operation of the unit for any one hour (i.e. divide the full-load gas flow rate by 4.2 percent).
- Multiply calculated natural gas transmission capacity needed by 85 percent to get the daily firm natural gas reservation quantity.
- Multiply the daily firm natural gas reservation quantity by the cost of incremental firm natural gas transportation (assumed for the IRP to be $1.60/MMBtu), and by 365 days/year to calculate the annual firm natural gas reservation fee.

7.1.7.2 Consideration of Existing Firm Interstate Natural Gas Transportation Capacity

For the first combined cycle or combined cycle conversion at GEC (i.e. 1x1 conversion or 2x1 conversion, new 1x1 7FA.05, new 1x1 7HA.02), the existing 100,000 MMBtu/day of firm interstate natural gas transportation capacity allocated to Northside 3 will be reallocated to the GEC combined cycle if Northside 3 is retired. For cases evaluated in this IRP in which Northside 3 does not retire, if a new combined cycle is added it would displace generation from Northside 3, resulting in an appropriate assumption that Northside 3 would then operate on interruptible natural gas. Given the assumed reallocation, there will be no incremental firm interstate natural gas transportation cost associated with either the first combined cycle conversion at GEC or the first addition of a new combined cycle at GEC.

7.1.7.3 Consideration of Local Natural Gas Transportation Capacity at GEC

All units located at GEC require local natural gas transportation capacity for use of either firm or interruptible natural gas. All natural gas delivery to the GEC site is via the existing SeaCoast pipeline and the GEC Lateral. Existing capacity of the GEC Lateral is adequate for some generating units considered in this IRP, while incremental capacity will be required for others, as follows:

- 100,000 MMBtu per day of local firm gas transportation capacity to GEC is currently purchased. The maximum hourly usage is 4.2 percent of the total firm daily quantity reserved. The cost of this capacity is $0.28/MMBtu, and the annual cost of this capacity is treated as a sunk cost.
- For any new construction at GEC requiring incremental local gas delivery beyond the current 100,000 MMBtu/day, capacity and cost are calculated as follows:

[5] Refer to the Levelized Cost of Energy screening discussion in Section 9.0 of this IRP for discussion of combined cycle alternatives.

- Calculate the full-load maximum hourly gas flow rate for the entire site by summing individual unit flow rates calculated using full-load output at net plant heat rate for each unit (at average ambient conditions, with duct firing, and reflecting non-recoverable degradation).
- Calculate daily firm natural gas transportation capacity quantity that would need to be reserved such that 4.2 percent of the total daily quantity is equivalent to the full-load maximum gas flow rate for the site (i.e. divide max hourly flow by 4.2 percent).
- Subtract the existing 100,000 MMBtu capacity from the calculated natural gas transmission capacity needed. This is the incremental daily firm natural gas reservation quantity.
- Multiply the incremental daily firm natural gas reservation quantity by the cost of incremental firm natural gas transportation (assumed for the IRP to be $0.28/MMBtu), and by 365 days/year to calculate the annual incremental firm local natural gas transportation capacity fee for GEC.

7.1.7.4 Consideration of Local Natural Gas Transportation Capacity at North Jacksonville Site

All units located at the North Jacksonville site require local gas transportation capacity. All local gas delivery to the North Jacksonville site will be accomplished via a new pipeline interconnecting with interstate gas transmission lines near the Brandy Branch plant. This new pipeline will be constructed to support the first unit constructed at North Jacksonville, and will have capacity adequate to supply potential future expansion of the North Jacksonville site[6]. The estimated cost of this line is $130 million, and this cost has been included in the capital cost of the first unit constructed at the North Jacksonville site, and not included in the capital cost of subsequent units.

7.1.7.5 Incremental Firm Natural Gas Transportation Costs for GEC Options

The following summarizes the methodology used to determine the incremental firm natural gas transportation costs for options at GEC, and also presents the resulting costs reflected in the analysis included in this IRP.

- For the first unit selected to be converted or added at GEC, no incremental interstate gas transmission is required, but incremental firm local gas transportation (SeaCoast and GEC Lateral) would be required as follows:
  - GEC 1x1 conversion as first unit– $0/year total gas transportation cost:
    - The existing interstate firm gas transmission capacity reallocated from Northside 3 is adequate to supply the 1x1 combined cycle conversion option at GEC, including duct firing.
    - The existing local firm gas transmission capacity to GEC is adequate to support the 1x1 combined cycle conversion option at GEC, including duct firing.
  - GEC 2x1 conversion as first unit – $300,000/year total gas transportation cost:
    - The existing interstate firm gas transmission capacity reallocated from Northside 3 is adequate to supply the 2x1 combined cycle conversion option at GEC, including duct firing.

[6] The potential synergy between pipelines for JEA generation and planned liquified natural gas (LNG) facilities in North Jacksonville has not been evaluated as part of this IRP.

- The existing local firm gas transmission capacity to GEC must increase by 3,000 MMBtu/day at a cost of $300,000/year to support the 2x1 combined cycle conversion option, including duct firing. (3,000 MMBtu/Day x 0.28 $/MMBTU x 365 days/year).

  - New GEC 1x1 7FA.05 combined cycle as first unit - $5,100,000/year total gas transportation cost:
    - The existing interstate firm gas transmission capacity reallocated from Northside 3 is adequate to supply a 1x1 7FA.05 combined cycle.
    - The local gas delivery capacity must increase by 50,000 MMBtu/day, at a cost of $5,100,000/year (50,000 MMBtu/Day x 0.28 $/MMBtu x 365 days/year).
  - New 1x1 7HA.02 combined cycle as first unit- $7,900,000/year gas total transportation cost:
    - The existing interstate firm gas transmission capacity reallocated from Northside 3 is adequate to supply a 1x1 7HA.02 combined cycle.
    - The local gas delivery capacity must increase by 77,000 MMBtu/day, at a cost of $7,900,000/year (72,000 MMBtu/day x 0.28 $/MMBtu x 365 days/year).
- If the first combined cycle selected for GEC is the GEC 1x1 combined cycle conversion, the second combined cycle could be a new 1x1 7FA.05 combined cycle, or a new 1x1 7HA.02 combined cycle. For either of these options, additional incremental firm interstate natural gas transportation and firm local gas transportation (SeaCoast and GEC Lateral) would be required as follows:
  - New 1x1 7FA.05 combined cycle at GEC (after GEC 1x1 combined cycle conversion) - $5,700,000/year gas transportation cost as follows:
    - The existing interstate firm gas transmission capacity re-allocated from Northside 3 is adequate to supply the new 1x1 7FA combined cycle after the 1x1 GEC combined cycle conversion.
    - The local gas delivery capacity (SeaCoast and GEC Lateral) must increase by 56,000 MMBtu/day, at a cost of $5,700,000/year (56,000 MMBtu/day * 0.28 $/MMBtu *365 days/year).
  - New 1x1 7HA.02 combined cycle at GEC (after GEC 1x1 combined cycle conversion) - $17,800,000/year gas transportation cost as follows:
    - The Interstate firm gas transmission must increase by 16,000 MMBtu/day, at a cost of $9,300,000/year (16,000 MMBtu/Day * 1.60 $/MMBtu * 365 days/year).
    - The local gas delivery capacity (SeaCoast and GEC Lateral) must increase by 83,000 MMBtu/day, at a cost of $8,500,000/year (83,000 MMBtu/day * 0.28 $/MMBtu*365 days/year).
- If the first combined cycle selected for GEC is the GEC 2x1 combined cycle conversion, the second combined cycle could be a new 1x1 7FA.05 combined cycle or a new 1x1 7HA.02 combined cycle. For either of these options, additional incremental firm interstate natural gas transportation and firm local gas transportation (SeaCoast and GEC Lateral) would be required as follows:
  - New 1x1 7FA.05 combined cycle at GEC (after GEC 2x1 combined cycle conversion) - $26,900,000/year gas transportation cost as follows:
    - The interstate firm gas transmission must increase by 36,000 MMBtu/day, at a cost of $21,000,000/year (36,000 MMBtu/day * 1.60 $/MMBtu * 365 days/year).

        - The local gas delivery capacity (SeaCoast and GEC Lateral) must increase by 58,000 MMBtu/day, at a cost of $5,900,000/year(58,000 MMBtu/day * 0.28 $/MMBtu *365 days/year).
    - New 1x1 7HA.02 combined cycle at GEC (after GEC 2x1 combined cycle conversion) - $43,200,000/year gas transportation cost as follows:
        - The Interstate firm gas transmission must increase by 60,000 MMBtu/day, at a cost of $34,500,000/year (59,000 MMBtu/day * 1.60 $/MMBtu * 365 days/year).
        - The local gas delivery capacity (SeaCoast and GEC Lateral) must increase by 85,000 MMBtu/day, at a cost of $8,700,000/year (85,000 MMBtu/day * 0.28 $/MMBtu *365 days/year).

7.1.7.6 Incremental Firm Natural Gas Transportation Costs for North Jacksonville Options

After the limitation of new generating units previously outlined at GEC has been reached, the IRP reflects the assumption that subsequent unit additions will be located at the North Jacksonville site. The following summarizes the methodology used to determine the incremental firm natural gas transportation costs for options at the North Jacksonville site (beyond the $130 million included in the capital cost of the first new unit constructed at the North Jacksonville site), and also presents the resulting costs reflected in the analysis included in this IRP.

- 1x1 7FA.05 combined cycle at North Jacksonville - $28.3 million/year firm natural gas transportation costs, based on requiring 48,500 MMBtu/day of incremental firm natural gas transportation capacity at a cost of $1.60/MMBtu.
- 1x1 7HA.02 combined cycle at North Jacksonville - $42.0 million/year firm natural gas transportation costs, based on requiring 72,000 MMBtu/day of incremental firm natural gas transportation capacity at a cost of $1.60/MMBtu.

7.1.7.7 Summary of Incremental Firm Natural Gas Transportation Costs Included for Combined Cycle Options

The previous subsections discussed the costs associated with incremental firm natural gas transportation capacity for each of the combined cycle options evaluated as part of this IRP. These costs are summarized in Figure 7-1.

	First New Unit @ GEC (Million$)			
Description	1x1 Combined Cycle Conversion	2x1 Combined Cycle Conversion	1x1 7FA.05 Combined Cycle	1x1 7HA.02 Combined Cycle
Annual Incremental Interstate Transportation Cost	$0.00	$0.00	$0.00	$0.00
Annual Incremental GEC Lateral Cost	$0.00	$0.30	$5.10	$7.90
Total Annual Incremental Transportation Cost	$0.00	$0.30	$5.10	$7.90

Description	1x1 7FA.05 Combined Cycle	1x1 7HA.02 Combined Cycle	1x1 7FA.05 Combined Cycle	1x1 7HA.02 Combined Cycle	1x1 7FA.05 Combined Cycle	1x1 7HA.02 Combined Cycle	1x1 7FA.05 Combined Cycle	1x1 7HA.02 Combined Cycle
Annual Incremental Interstate Transportation Cost	$0.00	$9.30	$21.00	$34.50				
Annual Incremental GEC Lateral Cost	$5.70	$8.50	$5.90	$8.70				
Total Annual]Incremental Transportation Cost	$5.70	$17.80	$26.90	$43.20	$28.30	$42.00	$28.30	$42.00
	Second New Unit @ GEC (Million$)				Second New Unit @ North Jacksonville (Million$)			

Figure 7-1

Summary of Firm Annual Natural Gas Transportation Costs for Combined Cycle Options

7.2 Solid Fuel Price Projections

The circulating fluidized bed (CFB) units the Northside Generating Station operate on a blend of coal (historically delivered from Colombia via waterborne vessel), petroleum coke, and natural gas, while Scherer 4 operates on low-sulfur Power River Basin (PRB) coal from the Wyoming region.

7.2.1 Northside Generating Station Solid Fuel Blend

For purposes of this IRP, it has been assumed that the CFBs at Northside Generating Station Northside Units 1 and 2) operate on a blend of 32 percent coal / 56 percent petroleum coke / 12 percent natural gas. The following subsections present the methodology used to develop the coal and petroleum coke price projections that comprise the solid fuel blend, and present the corresponding price projections.

7.2.1.1 Northside Coal Price Projections

The delivered coal price projections for Northside Units 1 and 2 were developed as follows:

- Commodity price projections for calendar years 2019 through 2021 were developed in $/short ton based on NYMEX MTF Contract[7] settle prices as of August 23, 2018.
- The 2021 coal price projection was escalated based on the annual escalation rates per the AEO2018 Reference Case projections for low sulfur Central Appalachian coal to develop commodity coal price projections through 2050.
- Vessel (transportation) costs (in 2018 $/short ton) were estimated by JEA based on actual calendar year 2015 through 2017 vessel costs for transportation of coal from Colombia to the Northside Generating Station.
- Resulting commodity and vessel costs were added to develop projected delivered coal prices to Northside Generating Station (in 2018 $/short ton), which were then converted to $/MMBtu (HHV) using an assumed heat content of 11,300 Btu/lb (HHV).
- The 2018 $/MMBtu delivered coal price projections were converted to nominal dollars at the 2.0 percent general inflation rate discussed in Section 5.0 of this IRP.

The components of the delivered coal price projections for the Northside Generating Station are shown in Table 7-5.

[7] MTF represents the Monthly Coal Price Index published in the Argus/McCloskey's Coal Price Index Report.

Table 7-5 Northside Generating Station - Delivered Coal Price Projections					
Year	Commodity Coal Price (2018 $/ Short Ton)	Vessel Costs (2018 $/ Short Ton)	Delivered Coal Price (2018 $/ Short Ton)	Delivered Coal Price (2018 $/MMBtu)	Delivered Coal Price (Nominal $/MMBtu)
2021	$73.01	$6.46	$79.47	$3.52	$3.73
2022	$72.80	$6.46	$79.26	$3.51	$3.80
2023	$72.66	$6.46	$79.12	$3.50	$3.87
2024	$73.21	$6.46	$79.67	$3.53	$3.97
2025	$73.31	$6.46	$79.77	$3.53	$4.05
2026	$73.43	$6.46	$79.89	$3.53	$4.14
2027	$72.41	$6.46	$78.87	$3.49	$4.17
2028	$72.53	$6.46	$78.99	$3.50	$4.26
2029	$72.10	$6.46	$78.56	$3.48	$4.32
2030	$71.88	$6.46	$78.34	$3.47	$4.40
2031	$71.77	$6.46	$78.23	$3.46	$4.48
2032	$71.36	$6.46	$77.82	$3.44	$4.54
2033	$71.05	$6.46	$77.51	$3.43	$4.62
2034	$71.05	$6.46	$77.51	$3.43	$4.71
2035	$71.04	$6.46	$77.50	$3.43	$4.80
2036	$70.98	$6.46	$77.44	$3.43	$4.89
2037	$71.31	$6.46	$77.77	$3.44	$5.01
2038	$71.88	$6.46	$78.34	$3.47	$5.15
2039	$72.64	$6.46	$79.10	$3.50	$5.30
2040	$73.46	$6.46	$79.92	$3.54	$5.47
2041	$73.82	$6.46	$80.28	$3.55	$5.60
2042	$74.47	$6.46	$80.93	$3.58	$5.76
2043	$75.01	$6.46	$81.47	$3.60	$5.91
2044	$75.71	$6.46	$82.17	$3.64	$6.08
2045	$76.67	$6.46	$83.13	$3.68	$6.28
2046	$77.08	$6.46	$83.54	$3.70	$6.44
2047	$77.96	$6.46	$84.42	$3.74	$6.63
2048	$78.93	$6.46	$85.39	$3.78	$6.84
2049	$80.03	$6.46	$86.49	$3.83	$7.07
2050	$81.08	$6.46	$87.54	$3.87	$7.30

7.2.1.2 Northside Petroleum Coke Price Projections

The petroleum coke price projections were developed based on the historical ratio of the price that JEA paid for petroleum coke to the price that JEA paid for coal delivered to the Northside Generating Station over the 2014 though 2017 period. This ratio of 80.6 percent was then applied to the projected delivered coal prices shown in the last column of Table 7-5. Resulting petroleum coke price projections are shown in Table 7-6.

Table 7-6
Delivered Petroleum Coke Price Projections

Year	Delivered Petroleum Coke (Nominal $/MMBtu)
2021	$3.01
2022	$3.06
2023	$3.12
2024	$3.20
2025	$3.27
2026	$3.34
2027	$3.36
2028	$3.43
2029	$3.48
2030	$3.54
2031	$3.61
2032	$3.66
2033	$3.72
2034	$3.79
2035	$3.87
2036	$3.94
2037	$4.04
2038	$4.15
2039	$4.28
2040	$4.41
2041	$4.51
2042	$4.64
2043	$4.77
2044	$4.90
2045	$5.06
2046	$5.19
2047	$5.35
2048	$5.52
2049	$5.70
2050	$5.88

7.2.1.3 Northside Blended Fuel Price Projections

Table 7-7 presents the Northside Generating Station blended fuel price projections, based on the natural gas, coal, and petroleum coke price projections discussed previously and the assumed blend of 32 percent coal / 56 percent petroleum coke / 12 percent natural gas.[8]

[8] Blended solid fuel forecast which includes some natural gas was prepared before final update of transportation adders used in the natural gas forecast. Some values are marginally different.

Table 7-7 Northside Generating Station Blended Fuel Price Projections	
Year	Coal/Petroleum Coke/Natural Gas Blend (Nominal $/MMBtu)
2021	$3.25
2022	$3.31
2023	$3.38
2024	$3.48
2025	$3.57
2026	$3.65
2027	$3.69
2028	$3.77
2029	$3.83
2030	$3.90
2031	$3.97
2032	$4.04
2033	$4.10
2034	$4.18
2035	$4.26
2036	$4.36
2037	$4.46
2038	$4.59
2039	$4.73
2040	$4.87
2041	$4.99
2042	$5.13
2043	$5.27
2044	$5.42
2045	$5.59
2046	$5.73
2047	$5.91
2048	$6.10
2049	$6.30
2050	$6.51

7.2.2 Scherer 4 Coal Price Projections

Scherer 4 operates on low sulfur Powder River Basin (PRB) coal sourced from Wyoming. Delivered coal price projections for Scherer 4 were developed as follows:

- Contractual freight on-board (FOB), or commodity, prices for calendar years 2019 through 2022.
- The 2022 FOB price was escalated based on the annual escalation rates per the AEO2018 Reference Case projections for low sulfur Wyoming PRB coal.

- Rail (transportation) costs for Norfolk Southern and Burlington Northern based on projections developed by JEA.
- Other transportation charges developed by JEA.

Given the confidential nature of the Scherer 4 contractual FOB coal prices, each component of the Scherer 4 coal price projections is not shown; instead, Table 7-8 presents the resulting delivered coal prices projections for Scherer 4 coal.

Table 7-8
Scherer 4 Delivered Coal Price Projections

Year	Scherer 4 Delivered Coal Prices (Nominal $/MMBtu)
2021	$2.56
2022	$2.62
2023	$2.69
2024	$2.75
2025	$2.82
2026	$2.89
2027	$2.95
2028	$3.02
2029	$3.09
2030	$3.16
2031	$3.22
2032	$3.29
2033	$3.37
2034	$3.45
2035	$3.54
2036	$3.62
2037	$3.71
2038	$3.79
2039	$3.88
2040	$3.96
2041	$4.05
2042	$4.14
2043	$4.23
2044	$4.32
2045	$4.42
2046	$4.51
2047	$4.60
2048	$4.70
2049	$4.79
2050	$4.90

7.3 Ultra-Low Sulfur No. 2 Fuel Oil

JEA's generating fleet includes dual-fuel capable units that can operate one either natural gas or No. 2 fuel oil (Kennedy Generating Station combustion turbines 7 and 8, as well as Brandy Branch combustion turbine 1) and units that can operate solely on No. 2 fuel oil (Northside Generating Station combustion turbines 3 through 6). For purposes of this IRP, the dual-fuel units are modeled as operating on natural gas, while the Northside Generating Station combustion turbines are modeled as operating on ultra-low sulfur No. 2 fuel oil (ultra-low sulfur).

The projected prices for No. 2 fuel oil were developed as follows:

- Price projections for calendar years 2019 through 2021 were developed in 2018 $/gallon based on NYMEX prices as of September 16, 2018.
- Prices per gallon for 2019 through 2021 were converted to $/MMBtu based on an assumed heat content of 137,381 Btu/gallon (HHV).
- The 2021 fuel oil price projection was escalated based on the annual escalation rates per the AEO2018 Reference Case projections for diesel fuel to price projections through 2050.
- The 2018 $/MMBtu price projections were converted to nominal dollars at the 2.0 percent general inflation rate discussed in Section 5.0 of this IRP.

The resulting No. 2 fuel oil price projections are shown in Table 7-9.

Table 7-9 No. 2 Fuel Oil Price Projections	
Year	No. 2 Fuel Oil Prices (Nominal $/MMBtu)
2021	$16.30
2022	$16.88
2023	$17.43
2024	$18.05
2025	$18.62
2026	$19.08
2027	$19.70
2028	$20.37
2029	$21.11
2030	$21.74
2031	$22.52
2032	$23.13
2033	$23.86
2034	$24.64
2035	$25.30
2036	$25.94
2037	$26.99
2038	$27.68
2039	$28.47
2040	$29.25
2041	$30.07
2042	$30.69
2043	$31.35
2044	$31.97
2045	$32.69
2046	$33.24
2047	$34.04
2048	$34.85
2049	$35.38
2050	$36.17

8.0 SUPPLY-SIDE OPTIONS

Various natural gas -fired and utility-scale solar photovoltaic (PV) generating resources were characterized in a separate study commissioned by JEA, with the intent that these future resource alternatives would be evaluated as part of this IRP. This *Characterization of Supply-Side Options*, in its current draft form, is included as Appendix B to this IRP. This section provides a summary of the estimated capital cost, operations and maintenance (O&M) costs, and performance characteristics for the options included in the *Characterization of Supply-Side Options* and discusses the economic evaluation process that was used to determine the appropriate options to be included for further consideration and evaluation in this IRP.

8.1 Summary of Supply-Side Options

The *Characterization of Supply-Side Options* included estimated capital costs, O&M costs, and performance characteristics for the following generating resources. For purposes of this IRP, it has been assumed that the natural gas-fired alternatives would either be installed at the existing Greenland Energy Center (GEC) or at a new brownfield site located on part of the property associated with the recently retired St. Johns River Power Park (SJRPP) units, referred to herein as the North Jax site. Alternatives are assumed to be first installed at GEC up to the assumed total site capacity, after which point subsequent alternatives would be installed at North Jax.

- Natural Gas-Fired Simple Cycle Combustion Turbines, Aeroderivatives, and Reciprocating Engines
    - General Electric (GE) 7F.05 simple cycle combustion turbine
    - GE 7HA.01 simple cycle combustion turbine
    - GE 7HA.02 simple cycle combustion turbine
    - GE LMS100 simple cycle aeroderivative
    - GE LM6000 simple cycle aeroderivative (2 units installed simultaneously)
    - GE Jenbacher J920 Flextra reciprocating engine (5 units installed simultaneously)
    - Wartsila 18V50SG reciprocating engine (5 units installed simultaneously)
- Natural Gas-Fired Combined Cycle Combustion Turbines
    - Existing GEC GE 7F.03 simple cycle combustion turbines upgraded to include a GE 7F.05 compressor and advanced gas path (AGP) upgrade and converted to either 1x1 or 2x1 combined cycle configuration
    - GE 7F.05 1x1 combined cycle
    - GE 7HA.01 1x1 combined cycle
    - GE 7HA.01 2x1 combined cycle
    - GE 7HA.02 1x1 combined cycle
    - GE 7HA.02 2x1 combined cycle (both wet cooling and air cooled condenser (ACC) alternatives)
    - GE 7HA.02 3x1 combined cycle
- Solar Photovoltaic (with and without battery storage)
    - 74.9 MW (AC) solar array, with and without battery storage

Tables 8-1 and 8-2 summarize the capital costs, operating costs, and performance for each of the natural gas-fired supply-side options assumed to be installed at GEC and North Jax, respectively. As shown in Tables 8-1 and 8-2, installation at GEC or North Jax has been assumed to affect the capital cost of each alternative. It should be noted that the capital costs for the options as shown in Tables 8-1 and 8-2 reflect estimates that assume each unit is the first unit installed at each site and as such may include infrastructure costs that, once incurred for the first unit, may not be required for future units (thereby resulting in lower costs for subsequent units); this consideration has been reflected in the detailed economic analysis presented in Section 10 of this IRP (and associated observations and conclusions discussed throughout this IRP) . However, the initial screening of the supply-side alternatives presented in Section 9 of this IRP only reflects the capital costs shown in Tables 8-1 and 8-2.

Capital and operating cost assumptions for the solar PV alternatives (with and without storage) are summarized below, based on information developed for and presented in the *Characterization of Supply-Side Options* that is included as Appendix B to this IRP. Of note the capital cost reflects the reduction to account for the 30 percent ITC (as discussed previously in this IRP), reflects estimated declining costs as technologies continue to mature, and is presented on a per kW (AC) basis while the fixed O&M reflects an annualized average of estimated annual maintenance and periodic major maintenance costs. Capital and operating costs for the solar with storage reflect the 75 MW/4-hour storage option included in the *Characterization of Supply-Side Options* as JEA indicated that would be the most appropriate option to evaluate given JEA's typical profile of electric demand.

- Solar without Storage
    - Capital Cost: $0.73/Watt (AC) in 2018 $, reflecting declining costs for installation in 2022 and 30% ITC
    - O&M: $12/kW (AC)-year in 2018$
- Solar with 75 MW/4-hours of Lithium Ion Storage
    - Capital Cost: $1.50/Watt (AC) in 2018 $, reflecting declining costs for installation in 2022 and 30% ITC
    - O&M: $20.50/kW (AC)-year in 2018$

Table 8-1
Summary of Natural Gas-Fired Supply-Side Options Installed at GEC Site

Supply Side Option	Capacity Factor	Duct Firing	Degraded Net Output (kW)[1]	Capital Cost - EPC + Owner's Costs ($M)[2]	Fixed O&M ($/kW-yr)[2, 3]	Non-Fuel Variable O&M ($/MWh)[2]	Degraded Full-Load Net Plant Heat Rate (BTU/kWh)[1]	$/kW Installed Capital Cost[1, 2, 4]
LM6000 PF Sprint 2X0	10%	No	88,135	97.8	14.98	6.52	9,482	$1,110
LMS100 PA+ 1X0	10%	No	109,453	116.9	12.27	4.16	8,933	$1,068
7FA.05 1X0	10%	No	223,459	106.3	8.00	14.92	10,072	$476
7FA.05 1X1	35%	Yes	350,410	414.5	10.41	4.83	6,843	$1,183
7FA.05 1X1	35%	No	333,302	414.5	10.41	4.83	6,758	$1,244
7FA.05 1X1	80%	Yes	350,410	414.5	10.41	2.67	6,843	$1,183
7FA.05 1X1	80%	No	333,302	414.5	10.41	2.67	6,758	$1,244
7HA.01 1X0	10%	No	258,149	120.7	7.12	18.53	9,483	$468
7HA.01 1X1	35%	Yes	415,401	475.1	9.02	5.69	6,585	$1,144
7HA.01 1X1	35%	No	396,578	475.1	9.02	5.69	6,494	$1,198
7HA.01 1X1	80%	Yes	415,401	475.1	9.02	2.59	6,585	$1,144
7HA.01 1X1	80%	No	396,578	475.1	9.02	2.59	6,494	$1,198
7HA.01 2X1	35%	Yes	834,231	736.4	5.83	5.61	6,558	$883
7HA.01 2X1	35%	No	796,130	736.4	5.83	5.61	6,469	$925
7HA.01 2X1	80%	Yes	834,231	736.4	5.83	2.52	6,558	$883
7HA.01 2X1	80%	No	796,130	736.4	5.83	2.52	6,469	$925
7HA.02 1X0	10%	No	341,648	165.6	5.64	17.41	9,452	$485
7HA.02 1X1	35%	Yes	545,400	487.3	7.28	5.32	6,519	$893
7HA.02 1X1	35%	No	520,675	487.3	7.28	5.32	6,434	$936
7HA.02 1X1	80%	Yes	545,400	487.3	7.28	2.26	6,519	$893
7HA.02 1X1	80%	No	520,675	487.3	7.28	2.26	6,434	$936

Table 8-1 (Continued)
Summary of Natural Gas-Fired Supply-Side Options Installed at GEC Site

Supply Side Option	Capacity Factor	Duct Firing	Degraded Net Output (kW)[1]	Capital Cost - EPC + Owner's Costs ($M)[2]	Fixed O&M ($/kW-yr)[2, 3]	Non-Fuel Variable O&M ($/MWh)[2]	Degraded Full-Load Net Plant Heat Rate (BTU/kWh)[1]	$/kW Installed Capital Cost[1, 2, 4]
7HA.02 2X1	35%	Yes	1,094,544	814.7	4.80	5.25	6,497	$744
7HA.02 2X1	35%	No	1,055,316	814.7	4.80	5.25	6,414	$772
7HA.02 2X1	80%	Yes	1,094,544	814.7	4.80	2.20	6,497	$744
7HA.02 2X1	80%	No	1,055,316	814.7	4.80	2.20	6,414	$772
7HA.02 3X1	35%	Yes	1,646,424	1035.0	4.23	5.22	6,478	$629
7HA.02 3X1	35%	No	1,570,924	1035.0	4.23	5.22	6,397	$659
7HA.02 3X1	80%	Yes	1,646,424	1035.0	4.23	2.18	6,478	$629
7HA.02 3X1	80%	No	1,570,924	1035.0	4.23	2.18	6,397	$659
7HA.02 1X1 ACC	35%	Yes	539,833	511.3	7.36	4.73	6,584	$947
7HA.02 1X1 ACC	35%	No	515,965	511.3	7.36	4.73	6,493	$991
7HA.02 1X1 ACC	80%	Yes	539,833	511.3	7.36	1.64	6,584	$947
7HA.02 1X1 ACC	80%	No	515,965	511.3	7.36	1.64	6,493	$991
7F.03 Upgraded 2X1	35%	Yes	622,075	513.3	6.92	4.72	6,905	$1,594
7F.03 Upgraded 2X1	35%	No	591,440	513.3	6.92	4.72	6,806	$1,761
7F.03 Upgraded 2X1	80%	Yes	622,075	513.3	6.92	2.64	6,905	$1,594
7F.03 Upgraded 2X1	80%	No	591,440	513.3	6.92	2.64	6,806	$1,761
7F.03 Upgraded 1X1	35%	Yes	309,681	284.4	11.50	4.81	6,935	$1,781
7F.03 Upgraded 1X1	35%	No	294,540	284.4	11.50	4.81	6,833	$1,968
7F.03 Upgraded 1X1	80%	Yes	309,681	284.4	11.50	2.72	6,935	$1,781
7F.03 Upgraded 1X1	80%	No	294,540	284.4	11.50	2.72	6,833	$1,968
J920 5X0	11.4%	No	44,556	63.9	42.11	9.59	7,962	$1,434
18V50SG 5X0	11.4%	No	89,800	107.5	20.81	8.45	8,526	$1,197

Notes:
1. Output and net plant heat rate are based on 69 F ambient temperature. Net plant heat rate is presented on a higher heating value (HHV) basis.
2. Capital and O&M costs are presented in 2018 dollars. Capital costs do not include interest during construction, which is accounted for in the detailed economic analyses performed for this IRP.
3. Fixed O&M costs do not include costs for natural gas transportation, which are discussed in Section 7.0 of this IRP and are accounted for in the detailed economic analyses performed for this IRP.
4. Estimated $/kW Installed Capital Cost for the 7F.03 Upgraded 2x1 (GEC 2x1 Combined Cycle Conversion) and 7F.03 Upgraded 1x1 (GEC 1x1 Combined Cycle Conversion) reflect estimated incremental capacity resulting from the conversion as compared to the capacity of the existing GEC simple cycle combustion turbines.

Table 8-2
Summary of Natural Gas-Fired Supply-Side Options Installed at North Jax Site

Supply Side Option	Capacity Factor	Duct Firing	Degraded Net Output (kW)[1]	Capital Cost - EPC + Owner's Costs ($M)[2]	Fixed O&M ($/kW-yr)[2, 3]	Non-Fuel Variable O&M ($/MWh)[2]	Degraded Full-Load Net Plant Heat Rate (BTU/kWh)[1]	$/kW Installed Capital Cost[1, 2]
LM6000 PF Sprint 2X0	10%	No	88,135	234.5	14.98	6.52	9,482	$2,661
LMS100 PA+ 1X0	10%	No	109,453	253.6	12.27	4.16	8,933	$2,317
7FA.05 1X0	10%	No	223,459	245.0	8.00	14.92	10,072	$1,096
7FA.05 1X1	35%	Yes	350,410	557.9	10.41	4.83	6,843	$1,592
7FA.05 1X1	35%	No	333,302	557.9	10.41	4.83	6,758	$1,674
7FA.05 1X1	80%	Yes	350,410	557.9	10.41	2.67	6,843	$1,592
7FA.05 1X1	80%	No	333,302	557.9	10.41	2.67	6,758	$1,674
7HA.01 1X0	10%	No	258,149	259.4	7.12	18.53	9,483	$1,004
7HA.01 1X1	35%	Yes	415,401	618.4	9.02	5.69	6,585	$1,489
7HA.01 1X1	35%	No	396,578	618.4	9.02	5.69	6,494	$1,559
7HA.01 1X1	80%	Yes	415,401	618.4	9.02	2.59	6,585	$1,489
7HA.01 1X1	80%	No	396,578	618.4	9.02	2.59	6,494	$1,559
7HA.01 2X1	35%	Yes	834,231	832.1	5.83	5.61	6,558	$997
7HA.01 2X1	35%	No	796,130	832.1	5.83	5.61	6,469	$1,045
7HA.01 2X1	80%	Yes	834,231	832.1	5.83	2.52	6,558	$997
7HA.01 2X1	80%	No	796,130	832.1	5.83	2.52	6,469	$1,045
7HA.02 1X0	10%	No	341,648	305.4	5.64	17.41	9,452	$894
7HA.02 1X1	35%	Yes	545,400	631.8	7.28	5.32	6,519	$1,158
7HA.02 1X1	35%	No	520,675	631.8	7.28	5.32	6,434	$1,213
7HA.02 1X1	80%	Yes	545,400	631.8	7.28	2.26	6,519	$1,158
7HA.02 1X1	80%	No	520,675	631.8	7.28	2.26	6,434	$1,213

Table 8-2 (Continued)
Summary of Natural Gas-Fired Supply-Side Options Installed at North Jax Site

Supply Side Option	Capacity Factor	Duct Firing	Degraded Net Output (kW)[1]	Capital Cost - EPC + Owner's Costs ($M)[2]	Fixed O&M ($/kW-yr)[2, 3]	Non-Fuel Variable O&M ($/MWh)[2]	Degraded Full-Load Net Plant Heat Rate (BTU/kWh)[1]	$/kW Installed Capital Cost[1, 2]
7HA.02 2X1	35%	Yes	1,094,544	861.5	4.80	5.25	6,497	$787
7HA.02 2X1	35%	No	1,055,316	861.5	4.80	5.25	6,414	$816
7HA.02 2X1	80%	Yes	1,094,544	861.5	4.80	2.20	6,497	$787
7HA.02 2X1	80%	No	1,055,316	861.5	4.80	2.20	6,414	$816
7HA.02 3X1	35%	Yes	1,646,424	1084.2	4.23	5.22	6,478	$658
7HA.02 3X1	35%	No	1,570,924	1084.2	4.23	5.22	6,397	$690
7HA.02 3X1	80%	Yes	1,646,424	1084.2	4.23	2.18	6,478	$658
7HA.02 3X1	80%	No	1,570,924	1084.2	4.23	2.18	6,397	$690
7HA.02 1X1 ACC	35%	Yes	539,833	655.8	7.36	4.73	6,584	$1,215
7HA.02 1X1 ACC	35%	No	515,965	655.8	7.36	4.73	6,493	$1,271
7HA.02 1X1 ACC	80%	Yes	539,833	655.8	7.36	1.64	6,584	$1,215
7HA.02 1X1 ACC	80%	No	515,965	655.8	7.36	1.64	6,493	$1,271
J920 5X0	11.4%	No	44,556	70.8	42.11	9.59	7,962	$1,590
18V50SG 5X0	11.4%	No	89,800	114.4	20.81	8.45	8,526	$1,274

Notes:
1. Output and net plant heat rate are based on 69 F ambient temperature. Net plant heat rate is presented on a higher heating value (HHV) basis.
2. Capital and O&M costs are presented in 2018 dollars. Capital costs do not include interest during construction, which is accounted for in the detailed economic analyses performed for this IRP.
3. Fixed O&M costs do not include costs for natural gas transportation, which are discussed in Section 7.0 of this IRP and are accounted for in the detailed economic analyses performed for this IRP.

9.0 SUPPLY-SIDE SCREENING

In order to compare the economics of the supply-side options discussed previously, a levelized cost of energy (LCOE) screening analysis was performed. Although the LCOE analysis does not evaluate how each supply-side option may fit into JEA's portfolio of generation resources, the LCOE is a useful screening mechanism that reduces the number of options considered in the detailed economic evaluations discussed in Section 8 of this IRP, providing for a more manageable number of options for consideration in the detailed economic analyses that is discussed in Section 10 of this IRP.

The remainder of this section provides a description of the LCOE approach and presents and discusses the results of the LCOE analysis.

9.1 Approach

The LCOE analysis considered capital costs, operating costs, and fuel costs (as appropriate for each supply-side option; as an example, evaluation of a power purchase agreement for solar would not have capital or fuel cost components) and expresses the total annual cost and corresponding energy generation on a nominal (current year) and present value basis. The cumulative present value costs are divided by the sum of the annual present worth factors to calculate the lifecycle levelized cost of energy for each option. Such an approach is widely used in comparing the relative economics of various supply-side options to determine if one (or more) option may be consistently more costly than the others across a range of possible capacity factors, allowing an initial list of supply-side options to be reduced to a smaller number to be considered in subsequent evaluations.

As stated previously, the LCOE calculated using a number of cost components that are specific to each supply-side option; these cost components are outlined below:

- Levelized annual capital cost – the levelized annual capital cost (or debt service) of each supply-side option is determined by applying the levelized fixed charge rate, which is discussed in Section 5.0 of this IRP, to the estimated capital cost of the option. The basis for the capital cost estimates is discussed in detail in Appendix B (*Characterization of Supply-Side Options*) to this IRP.
- Annual fixed and variable O&M costs - fixed and variable O&M costs are based on first year costs. Each successive year is escalated at the 2.0 percent escalation rate discussed in Section 5.0 of this IRP.
- Annual fuel costs – annual fuel costs were calculated based on the net heat rate of each supply-side options using the natural gas price projections are presented in Section 7.0 of this IRP.
- Natural gas transportation costs – costs associated with natural gas transportation capacity for the supply-side options are reflected in the LCOE calculations, based on the natural gas transportation considerations and associated costs discussed in Section 6.0 of this IRP.

The annual total cost is determined by summing the appropriate components listed above. To determine the LCOE, the annual total cost is divided by the annual generation (assumed to be delivered to the busbar), resulting in an annual cost per kWh. Discounting the annual cost per kWh by the present worth discount rate (PWDR) for each year produces the present worth or discounted annual bus-bar cost. By summing each discounted annual cost per kWh and dividing it by the sum of the present worth factors, the LCOE is derived, as reflected in the following formula (in which "n" represents the year of the LCOE analysis).

$$LCOE = \frac{\sum_{n=1}^{Y} Discounted\ Annual\ Busbar\ Cost}{\sum_{n=1}^{Y} \frac{1}{(1+PWDR)^n}}$$

An example calculation which implements these steps is presented in Table 9-1. This analysis is for the addition of a new GE 7HA.02 1x1 combined cycle at the Greenland Energy Center, assumed to operate at a 65 percent capacity factor.

9.2 LCOE Screening Results

The LCOE for each of the supply-side options considered in this IRP is summarized in Table 9-2 (for units installed at GEC and reflecting the cost and operating characteristics discussed in Section 8.0 of this IRP). As shown in Table 9-2, the amount of annual generation (represented in Table 9-2 by capacity factor) has a significant impact on the levelized cost of each supply-side option (specifically, increased capacity factors reduce the LCOE as fixed costs are spread over increased generation). In this regard, when comparing the LCOE of the supply-side options, it is important to consider the capacity factor at which the different options are expected to operate. For example, simple cycle units may be expected to operate as peaking units that generally operate during times at or near system peak (or if other units are not available), and may be expected to operate at annual capacity factors less than 25 percent, while combined cycle units may be expected to operate as intermediate or baseload units that operate significantly more hours of the year than peaking units (i.e. at annual capacity factors between 30 to 90 percent, depending upon whether other existing baseload resources are available). Accordingly, it is important to compare the LCOE of similar technologies when evaluating whether certain supply-side options can be eliminated from further consideration based on the LCOE results. For example, comparison of the LCOE of a simple cycle option at a 10 percent capacity factor to the LCOE of a combined cycle option at an 80 percent capacity factor is not a relevant comparison, and such a comparison may result in the elimination of the simple cycle option that may be economic when compared to other peaking options. Likewise, comparison of solar PV technologies to conventional capacity is not a relevant comparison. None of the solar PV or solar plus 4 hour battery charged by solar technologies evaluated in this IRP can supply capacity and ancillary services on a 24x7 basis like conventional resource options. Solar and solar plus battery options are advantageous in scenarios that represents a future in which increased environmental regulations result in a carbon tax, clean energy standards, and high natural gas prices.

Table 9-2 includes bold formatting as well as highlighting to illustrate the appropriate ranges of capacity factors for which the LCOE of supply-side options should be evaluated and compared (consistent with the previous discussion of peaking and intermediate/baseload technologies). The solar PV options (with and without storage) were evaluated at a single capacity factor (22 percent) based on the estimated capacity factor for a single-axis tracking solar PV installation in or near Jacksonville; for presentation purposes, the LCOE of the solar PV options are shown at 20 percent capacity factors in Table 9-2. Figures 9-1 and 9-2 present the LCOE for the peaking and combined cycle options, respectively, across a representative range of capacity factors appropriate for each type of technology for units installed at GEC (Figure 9-1 also includes the LCOE of solar PV with and without storage for comparison purposes).

As discussed in Section 8.0 of this IRP, JEA may install new supply-side options at either the existing GEC site or at a new brownfield site located on part of the property associated with the recently retired St. Johns River Power Park (SJRPP) units, referred to herein as the North Jax site. For informational purposes, a comparison of the LCOE for supply-side options constructed at GEC against supply-side options constructed at North Jax (at a representative capacity factor for peaking and intermediate/baseload units) is shown in Figure 9-3.

Table 9-1 – Example LCOE Calculation for GE 7HA.02 1x1 Combined Cycle at 65 % Capacity Factor

Levelized Cost of Energy (LCOE) Analysis					
Generator Description, Capital Cost, and Performance for:	7HA.02 1X1	O&M, Fuel, and Financing	Base Year	Escalation	Comments
Net Output (kW)	520,675	Non-Fuel Variable O&M ($/MWh)	$3.28	2.0%	2018 $
Capital Cost ($000; excludes IDC and Escalation)	$487,270	Fixed O&M ($/kW-Yr)	$7.28	2.0%	2018 $
Net Plant Heat Rate (Btu/kWh, HHV)	6,434	Initial Natural Gas Price ($/MMBtu)	$3.19	Varies	Baseline NG Price, wo/ITS Adder
Capacity Factor	65.0%	Present Worth Discount Rate	4.50%	N/A	
Net Generation (MWh)	2,964,723	Capital Recovery Factor	7.31%	N/A	

Year	Levelized Capital Cost ($000)	Fixed O&M ($000)	Non-Fuel Variable O&M ($000)	Natural Gas Price ($/MMBtu)	Natural Gas Cost ($000)	Firm Natural Gas Reservation Cost ($000)	Other ($000)	Other ($000)	Total Cost ($000)	Total Cost (c/kWh)	Present Worth Cost (c/kWh)
2022	$35,629	$4,104	$10,522	$3.19	$60,816	$7,900	$0	$0	$118,971	4.01	3.22
2023	$35,629	$4,186	$10,733	$3.36	$64,073	$7,900	$0	$0	$122,521	4.13	3.17
2024	$35,629	$4,269	$10,947	$3.52	$67,101	$7,900	$0	$0	$125,847	4.24	3.12
2025	$35,629	$4,355	$11,166	$3.70	$70,502	$7,900	$0	$0	$129,553	4.37	3.07
2026	$35,629	$4,442	$11,390	$3.81	$72,596	$7,900	$0	$0	$131,957	4.45	3.00
2027	$35,629	$4,531	$11,617	$3.93	$74,919	$7,900	$0	$0	$134,597	4.54	2.92
2028	$35,629	$4,621	$11,850	$4.02	$76,730	$7,900	$0	$0	$136,730	4.61	2.84
2029	$35,629	$4,714	$12,087	$4.16	$79,423	$7,900	$0	$0	$139,753	4.71	2.78
2030	$35,629	$4,808	$12,329	$4.25	$81,084	$7,900	$0	$0	$141,750	4.78	2.70
2031	$35,629	$4,904	$12,575	$4.34	$82,769	$7,900	$0	$0	$143,778	4.85	2.62
2032	$35,629	$5,002	$12,827	$4.43	$84,591	$7,900	$0	$0	$145,949	4.92	2.54
2033	$35,629	$5,102	$13,083	$4.52	$86,175	$7,900	$0	$0	$147,889	4.99	2.47
2034	$35,629	$5,204	$13,345	$4.61	$87,893	$7,900	$0	$0	$149,971	5.06	2.39
2035	$35,629	$5,308	$13,612	$4.69	$89,419	$7,900	$0	$0	$151,868	5.12	2.32
2036	$35,629	$5,414	$13,884	$4.88	$93,018	$7,900	$0	$0	$155,846	5.26	2.28
2037	$35,629	$5,523	$14,162	$4.99	$95,134	$7,900	$0	$0	$158,347	5.34	2.21
2038	$35,629	$5,633	$14,445	$5.16	$98,373	$7,900	$0	$0	$161,981	5.46	2.17
2039	$35,629	$5,746	$14,734	$5.31	$101,303	$7,900	$0	$0	$165,312	5.58	2.12
2040	$35,629	$5,861	$15,028	$5.44	$103,833	$7,900	$0	$0	$168,251	5.68	2.06
2041	$35,629	$5,978	$15,329	$5.58	$106,508	$7,900	$0	$0	$171,344	5.78	2.01
2042	$35,629	$6,098	$15,636	$5.76	$109,821	$7,900	$0	$0	$175,084	5.91	1.96
2043	$35,629	$6,220	$15,948	$5.92	$112,829	$7,900	$0	$0	$178,526	6.02	1.92
2044	$35,629	$6,344	$16,267	$6.09	$116,241	$7,900	$0	$0	$182,381	6.15	1.87
2045	$35,629	$6,471	$16,593	$6.27	$119,526	$7,900	$0	$0	$186,119	6.28	1.83
2046	$35,629	$6,600	$16,924	$6.44	$122,929	$7,900	$0	$0	$189,983	6.41	1.79
2047		$6,732	$17,263	$6.63	$126,456	$7,900	$0	$0	$158,351	5.34	1.43
2048		$6,867	$17,608	$6.87	$130,963	$7,900	$0	$0	$163,338	5.51	1.41
2049		$7,004	$17,960	$7.08	$135,129	$7,900	$0	$0	$167,993	5.67	1.39
2050		$7,144	$18,320	$7.33	$139,851	$7,900	$0	$0	$173,215	5.84	1.37
2051		$7,287	$18,686	$7.59	$144,739	$7,900	$0	$0	$178,612	6.02	1.35
								Levelized Cost of Energy (c/kWh)			**5.00**
								Levelized Cost of Energy ($/MWh)			**50.02**

Table 9-2
Summary of LCOE for Supply-Side Options at GEC and Solar PV Options

Supply-Side Option	LCOE ($/MWh) at Various Capacity Factors																	
	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%	80%	85%	90%
GEC LM6000 PF Sprint 2X0	**301.3**	**177.3**	**136.0**	**115.4**	**103.0**	94.7	88.8	84.4	80.9	78.2	75.9	74.0	72.5	71.1	69.9	68.9	68.0	67.2
GEC LMS100 PA+ 1X0	**268.2**	**163.4**	**128.5**	**111.1**	**100.6**	93.6	88.6	84.9	82.0	79.7	77.8	76.2	74.8	73.7	72.7	71.8	71.0	70.4
GEC 7FA.05 1X0	**225.7**	**141.9**	**114.0**	**100.1**	**91.7**	86.1	82.1	79.1	76.8	74.9	73.4	72.1	71.1	70.2	69.4	68.7	68.0	67.5
GEC 7HA.01 1X0	**209.6**	**139.7**	**116.4**	**104.8**	**97.8**	93.2	89.8	87.3	85.4	83.9	82.6	81.5	80.6	79.9	79.2	78.6	78.1	77.7
GEC 7HA.02 1X0	**206.4**	**137.3**	**114.3**	**102.7**	**95.8**	91.2	87.9	85.5	83.6	82.0	80.8	79.7	78.8	78.1	77.4	76.8	76.3	75.9
GEC J920 5X0	**408.8**	**229.6**	**169.9**	**140.1**	**122.1**	110.2	101.7	95.3	90.3	86.3	83.1	80.3	78.0	76.1	74.4	72.9	71.6	70.4
GEC 18V50SG 5X0	**327.7**	**189.6**	**143.6**	**120.6**	**106.8**	97.6	91.0	86.1	82.2	79.2	76.7	74.6	72.8	71.3	70.0	68.8	67.8	66.9
GEC 7FA.05 1X1	295.6	166.9	124.1	102.6	89.8	**81.2**	**75.1**	**70.1**	**66.2**	**63.0**	**60.4**	**58.1**	**56.1**	**54.4**	**52.8**	**51.4**	**50.5**	**49.6**
GEC 7HA.01 1X1	283.1	160.7	119.9	99.5	87.2	**79.1**	**73.2**	**68.4**	**64.5**	**61.3**	**58.6**	**56.3**	**54.3**	**52.4**	**50.8**	**49.3**	**48.4**	**47.6**
GEC 7HA.01 2X1	252.2	145.1	109.4	91.6	80.9	**73.7**	**68.6**	**64.3**	**60.9**	**58.0**	**55.6**	**53.5**	**51.7**	**50.0**	**48.5**	**47.2**	**46.4**	**45.7**
GEC 7HA.02 1X1	237.1	137.3	104.0	87.4	77.4	**70.7**	**66.0**	**62.0**	**58.7**	**56.0**	**53.7**	**51.8**	**50.0**	**48.5**	**47.0**	**45.6**	**44.9**	**44.3**
GEC 7HA.02 2X1	261.8	149.5	112.1	93.4	82.2	**74.7**	**69.3**	**64.9**	**61.3**	**58.3**	**55.8**	**53.7**	**51.8**	**50.1**	**48.5**	**47.1**	**46.3**	**45.6**
GEC 7HA.02 3X1	285.6	161.4	120.0	99.3	86.8	**78.6**	**72.6**	**67.7**	**63.8**	**60.6**	**57.9**	**55.5**	**53.5**	**51.7**	**50.0**	**48.5**	**47.6**	**46.8**
GEC 7HA.02 1X1 ACC	245.5	141.2	106.5	89.1	78.6	**71.7**	**66.7**	**62.5**	**59.2**	**56.4**	**54.0**	**52.0**	**50.2**	**48.5**	**47.1**	**45.7**	**45.0**	**44.3**
GEC 2X1 CC Conversion	331.8	185.6	136.9	112.5	97.9	**88.1**	**81.2**	**74.6**	**70.2**	**66.7**	**63.7**	**61.2**	**59.0**	**57.1**	**55.3**	**54.2**	**53.2**	**52.2**
GEC 1X1 CC Conversion	374.7	207.1	151.3	123.4	106.6	**95.4**	**87.5**	**80.2**	**75.2**	**71.2**	**67.8**	**65.0**	**62.5**	**60.3**	**58.4**	**57.1**	**55.9**	**54.8**
75 MW Solar PV without Storage				**50.0**														
75 MW Solar PV with 4 Hours Storage				**100.0**														

Notes:
- Bold formatting and highlighting illustrate the appropriate ranges of capacity factors for which the LCOE of supply-side options should be evaluated and compared (consistent with the previous discussion of peaking and intermediate/baseload technologies).
- Solar PV is not directly comparable to natural gas options that provide firm annual capacity.

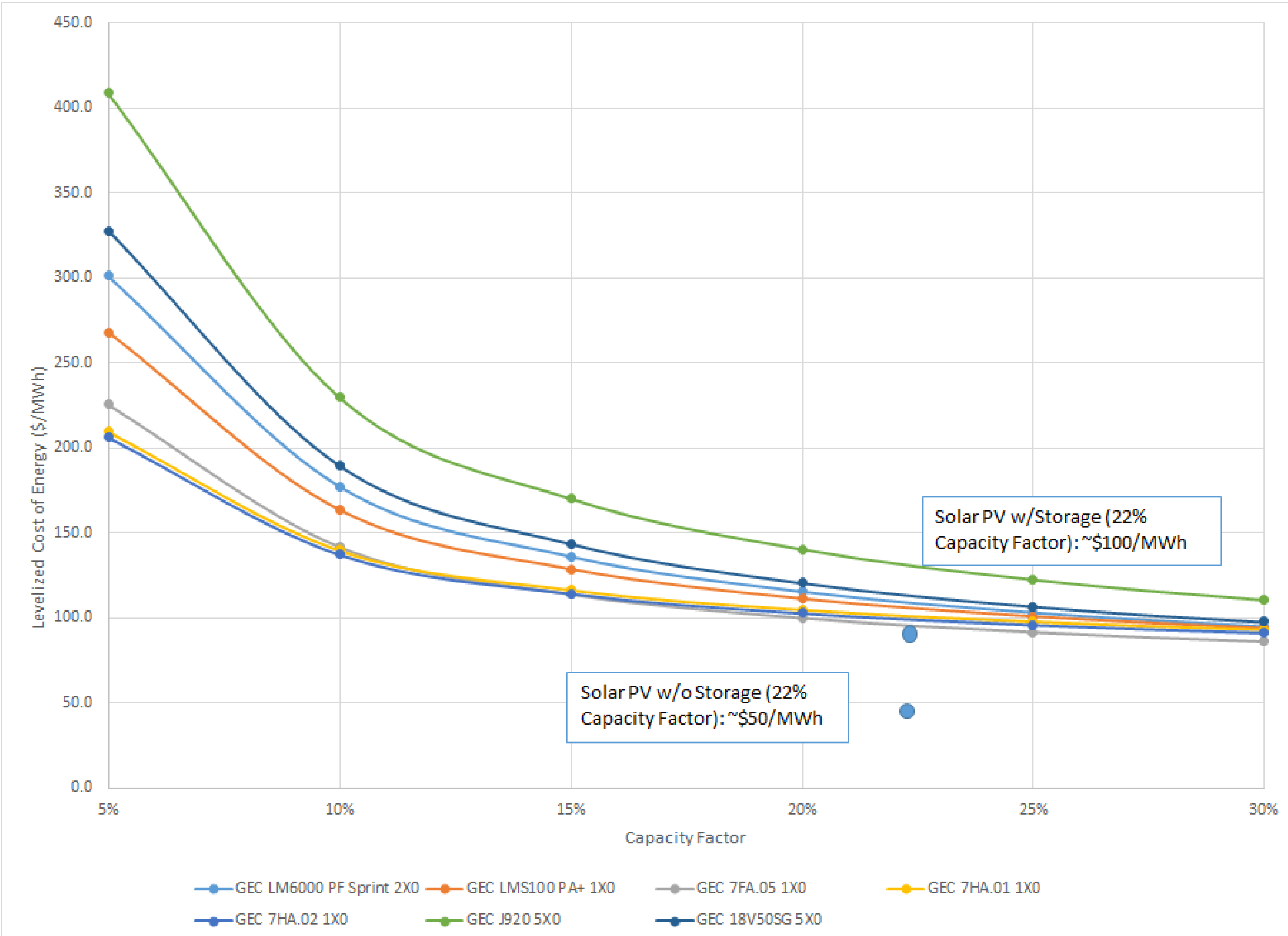

Figure 9-1
LCOE of Peaking Options Installed at GEC and Solar PV Options

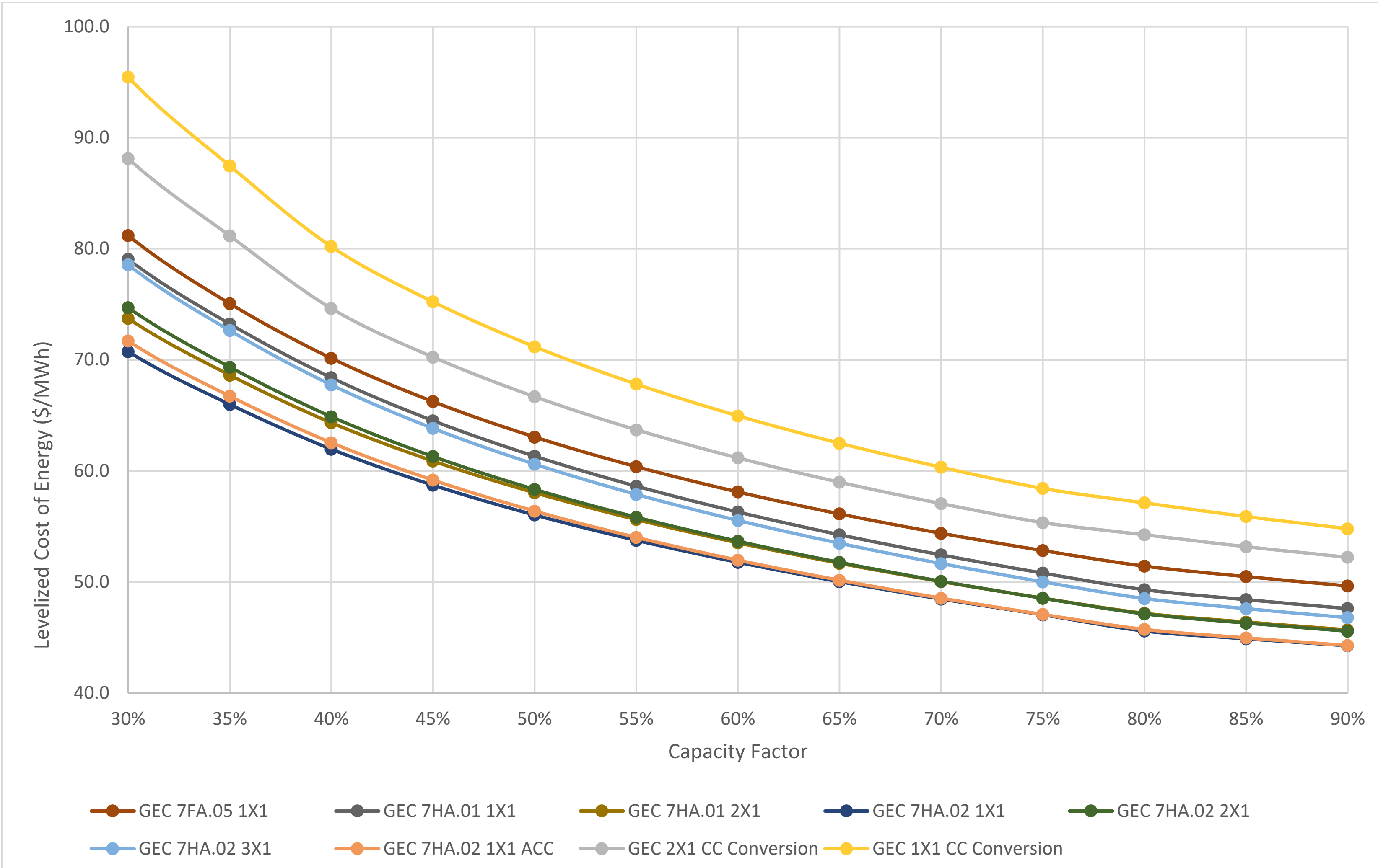

Figure 9-2
LCOE of Combined Cycle Options Installed at GEC

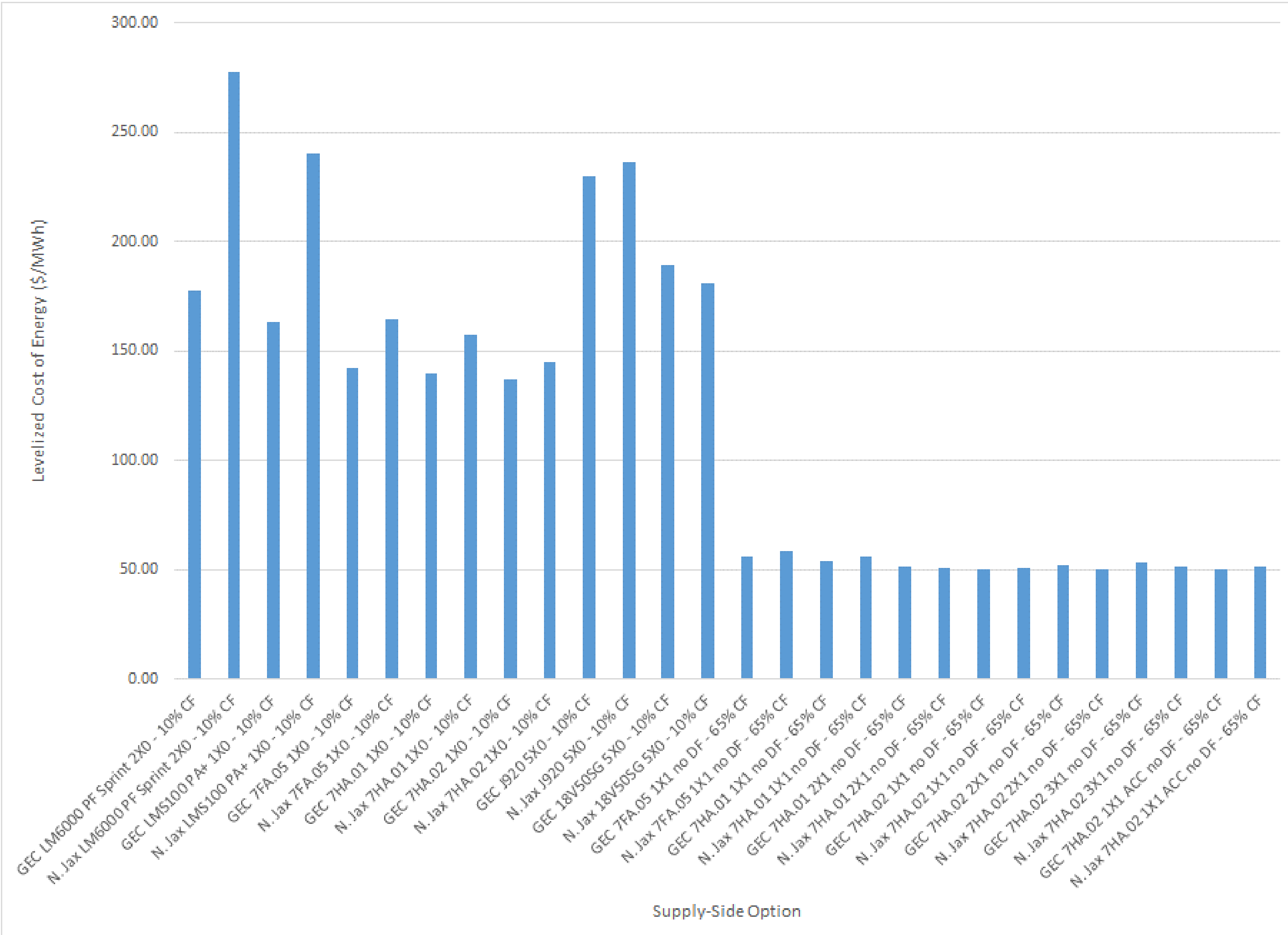

Figure 9-3
Comparison of LCOE for Options Constructed at GEC versus North Jax

9.3 Conclusions from LCOE Screening

The following presents the conclusions resulting from review of the LCOE information presented in Table 9-1 and illustrated in Figures 9-1 and 9-2.

- Simple Cycle and Solar Options
    - The GE 7HA.02 simple cycle is an economic peaking option and will be carried forward for consideration in the expansion planning and production cost analysis.
    - The 7HA.01 simple cycle will not be carried forward for further consideration, as the LCOE of the 7HA.02 simple cycle is lower across all capacity factors and the differential in capacity between the 7HA.01 and 7HA.02 simple cycle options is addressed by carrying forward the 7FA.05 simple cycle option (see below).
    - The 7FA.05 simple cycle will be carried forward. The LCOE is competitive with the LCOE of the 7HA.02 simple as capacity factors approach and exceed 15 percent, and the output of the 7FA.05 simple cycle relative to the output of the 7HA.02 simple cycle supports further consideration in the IRP.
    - The LMS100 simple cycle is an economic peaking option and will be carried forward for consideration in the expansion planning and production cost analysis.
    - The 2xLM6000 simple cycle will not be carried forward for further consideration, as the LCOE is higher than the LCOE of the LMS100 simple cycle across all capacity factors considered, and total capacity is similar to that of the LMS100 simple cycle. JEA may want to perform further evaluation of the 2xLM6000 simple cycle as an alternative to the LMS100 simple cycle if the LMS100 simple cycle is indicated to be included in optimal generation expansion plans identified in the IRP.
    - The 5xJ920 (Jenbachers) will be carried forward for further consideration. The 5x18V50SG (Wartsilas) will not be carried forward, as the LCOE is higher than the LCOE of the LMS100 simple cycle across all capacity factors considered, and total capacity is similar to that of the LMS100 simple cycle. JEA may want to perform further evaluation of the Wartsilas as an alternative to the LMS100 simple cycle or Jenbachers if the LMS100 simple cycle or Jenbachers are indicated to be included in optimal generation expansion plans identified in the IRP.
    - Solar (with and without storage) sized at 75 MW will be carried forward for consideration in the expansion planning and production cost analysis.
- Combined Cycle Options
    - The 7HA.02 3x1 combined cycle will not be carried forward for further consideration, as the amount of capacity associated with the unit is not appropriate for JEA to consider and it is not economical when compared to other combined cycle options, primarily due to the volume of firm natural gas transportation that would need to be reserved.
    - The 7HA.02 2x1 combined cycle will not be carried forward for further consideration, as the amount of capacity associated with the unit is not appropriate for JEA to consider and it is not economical when compared to other combined cycle options, primarily due to the volume of firm natural gas transportation that would need to be reserved.
    - The 7HA.01 2x1 combined cycle will not be carried forward for further consideration, as the amount of capacity associated with the unit is not appropriate for JEA to consider and it is not economical when compared to other combined cycle options, primarily due to the volume of firm natural gas transportation that would need to be reserved.

- The 7HA.02 1x1 combined cycle is an economic and appropriately sized combined cycle option and will be carried forward for consideration in the expansion planning and production cost analysis.
- The 7HA.02 1x1 with ACC combined cycle will not be carried forward for further consideration. The LCOE of the 7HA.02 1x1 ACC combined cycle is higher than or nearly the same as the LCOE of the 7HA.02 1x1 combined cycle, and JEA does not feel there is a need to consider an ACC rather than wet cooling.
- The 7HA.01 1x1 combined cycle will not be carried forward for further consideration. Although the LCOE is lower than the LCOE of the 7FA.05 1x1 combined cycle, the analysis will include consideration of an H-class combined cycle (the 7HA.02 1x1), and consideration of the 7FA.05 1x1 combined cycle allows for comparison of a combined cycle alternative with greater differential in capacity than the 7HA.01 1x1 combined cycle as compared to the 7HA.02 1x1 combined cycle.
- The 7FA.05 1x1 combined cycle is an economic and appropriately sized combined cycle option and will be carried forward for consideration in the expansion planning and production cost analysis.
- Both the 2x1 and 1x1 GEC combined cycle conversions will be carried forward. Although the LCOE of these options does not look competitive as compared to the other combined cycle options, analysis of the benefits of combined cycle conversion should be performed through production cost modeling as part of the IRP in order to allow for analysis of the potential advantages of realizing the associated incremental capacity and transition from simple cycle to combined cycle generation for JEA .

10.0 EXPANSION PLANNING AND PRODUCTION COST ANALYSES

Detailed expansion planning and production cost modeling were performed for this IRP using Strategist and PROMOD, respectively, both of which are industry accepted models licensed through ABB (formerly Ventyx). Both Strategist and PROMOD have been used in various public service commission resource planning filings in Florida and other states, and Strategist was used in JEA's previous IRP (in the 2011 timeframe). High level summary of each of these models is presented below.

- Strategist, a capacity expansion optimization computer model, was used to evaluate combinations of generating alternatives expected to be available to JEA (as discussed in Section 8 of this IRP) to meet future demand and energy requirements for each of the scenarios and several sensitivity cases. Strategist evaluates a typical week in each month of the year over the analysis period to optimize the least-cost generation alternatives considering peak demand, energy needs, fuel and emissions prices, fixed and variable operating costs, capital costs, and other factors, and estimates annual system costs. The software was used to evaluate the economics of the conventional and renewable alternatives that were carried forward following the LCOE screening analysis presented in Section 9.0 of this IRP.
- The expansion plans developed using Strategist were carried forward to the production cost analysis performed using PROMOD. The PROMOD analysis provides an optimized hourly simulation of generation commitment and dispatch, based on an hourly depiction of JEA's loads and all generating unit characteristics (e.g., capacity ratings, heat rate curves, availability, and minimum run time requirements), and considering system reliability and minimum reserve requirements.

The remainder of this section summarizes the methodology used for the expansion planning and production cost modeling of the Scenarios, including sensitivity analyses to reflect changes to the load forecast and natural gas price projections, as well as the results of the corresponding economic analysis.

10.1 Methodology

The analysis period reflected in this IRP includes 2019 through 2050, and economic evaluations were performed and are presented in nominal dollars using the 2.0 percent inflation rate discussed in Section 5.0 of this IRP. The cumulative present worth cost (CPWC) analysis used as the basis for the economic results and associated comparisons reflect the 4.5 percent present worth discount rate discussed in Section 5.0 of this IRP. As illustrated in Tables 4-1 and 4-2, under the base load forecast JEA anticipates near-term seasonal capacity requirements in 2020 through 2022, which JEA expects to be met utilizing short-term, seasonal market purchases via TEA. Capacity requirements are anticipated to again materialize beginning in the 2025/26 timeframe, and those capacity requirements are used in the analyses performed as part of, and discussed throughout, this IRP.

As discussed previously in this IRP, various scenarios and sensitivities were considered to reflect changes to key evaluation parameters and assumptions and allow for comparison of competing expansion plans (and associated new generating resource additions) across a wide range of potential futures. The Baseline Scenario, and associated base load and fuel price projections, is intended to reflect what JEA and nFront believe to be the most reasonable set of assumptions and corresponding projections based on current and expected likely future considerations. The other scenarios included in the IRP consist of the Load

Erosion, Increased Electrification, and Green Economy scenarios; each of the scenarios is outlined below and summarized in Table 10-1.

- **Baseline Scenario** – The Baseline Scenario represents a projection of the future based on current conditions, and reflects relatively low average annual growth rates for both annual energy requirements (0.87 percent) and summer and winter peak demand (0.70 percent and 0.86 percent, respectively). Northside 3 is assumed to retire in September 2025 due to environmental considerations and the age of the unit. No new environmental regulations or clean energy standards are assumed, and (except for Northside 3), none of JEA's generating units are assumed to retire. The following sensitivities were considered within the Baseline Scenario: high load growth, low load growth, high natural gas prices, and low natural gas prices.
- **Load Erosion Scenario** – The Load Erosion Scenario represents a future in which both annual energy requirements and summer and winter peak demands decline at 1.0 percent annually for 10 years, and then remain constant for the remainder of the evaluation period. Other assumptions are identical to those in the Baseline Scenario, except that the Load Erosion Scenario includes higher interest during construction, present worth discount, and general escalation rates.
- **Increased Electrification Scenario** – The Increased Electrification Scenario represents a future in which electrification increases in the near term such that both annual energy requirements and summer and winter peak demands increase at 2.0 percent annually until reaching levels that are 20 percent higher than in the Baseline Scenario, and then increase at the average annual growth rates from the Baseline Scenario thereafter. Other assumptions are identical to those in the Baseline Scenario.
- **Green Economy Scenario** – The Green Economy Scenario represents a future in which increased environmental regulations result in a carbon tax, clean energy standards, and high natural gas prices, with JEA retiring Northside 3 in September 2025 and retiring all of its other solid fuel units in 2030. Costs for construction of new generating units increase 1.0 percent more than the general escalation rate. Forecast annual energy requirements are similar to the Baseline Scenario, but summer and winter peak demand are assumed to increase at 1.6 percent annually.

Table 10-1
Summary of IRP Scenarios

Area	Metric	Baseline Scenario	Load Erosion Scenario	Increased Electrfication Scenario	Green Economy Scenario
Financial	Interest During Construction & Discount Rate	4.50%	6%	4.50%	4.50%
	Escalation Rate	2.00%	3.00%	2.00%	2.00%
Demand	Total Net Energy Requirements Forecast	AAGR: 0.87%	Energy requirements decline by 1.0% /year for 10 years; then no growth	Energy requirements increase at 2.0%/year until achieve +20% over Baseline forecast; then Baseline AAGR of 0.87% thereafter {See Comment}	AAGR: 0.89%
	Net Firm Peak Demand Forecast	AAGR Winter: 0.86% AAGR Summer: 0.70%	Winter and Summer net firm peak demand declines at 1.0% for 10 years; then no growth	Winter and Summer net firm peak demand increase at 2.0%/year until achieve +20% over Baseline forecast; Baseline Winter and Summer AAGR thereafter	AAGR Winter: 1.6% AAGR Summer: 1.6%
	EE/Conservation	Current Portfolio	Embedded in Energy Forecast	Embedded in Energy Forecast	Embedded in Energy Forecast
	Direct Load Control	None	None	None	None
	Interruptible Load	Current Portfolio	Embedded in Peak Demand Forecast	Embedded in Peak Demand Forecast	Embedded in Peak Demand Forecast
	PEV	0.5% by 2027 3.6% by 2046	Embedded in Energy and Peak Demand Forecasts	Embedded in Energy and Peak Demand Forecasts	Embedded in Energy and Peak Demand Forecasts
	Net Metering	Current Portfolio	Embedded in Energy and Peak Demand Forecasts	Embedded in Energy and Peak Demand Forecasts	Embedded in Energy and Peak Demand Forecasts
Environmental Regulations	Carbon Tax Rate	None	None	None	~ $11.50/ton in 2020, increasing at 5% annually
	Clean Energy Standard (CES)	None	None	None	Reflect 30% carbon neutral by 2030
Supply	Fuel Cost & Availability	Gas supply remains adequate with moderate pricing	Gas supply remains adequate with moderate pricing	Gas supply remains adequate with moderate pricing	Gas supply inadequate with high pricing
	Construction Cost	Costs increase at inflation	Costs increase at inflation	Costs increase at inflation	Costs increase at inflation through 2020, inflation + 1% thereafter
	Unit Retirements	Northside 3: 2025; Solid Fuel: none expected	Northside 3: 2025; Solid Fuel: none expected	Northside 3: 2025; Solid Fuel: none expected	Northside 3: 2025; Solid Fuel: 2030

The following figures are presented to illustrate the differences between load forecasts and natural gas price projections evaluated in this IRP within each of the scenarios and the sensitivities performed within the Baseline Scenario.

- Figure 10-1 presents a comparison of the summer peak demand forecasts. Note that the forecasts for the various scenarios and sensitivities were developed to reflect deviations based upon the base case summer peak demand forecast.
- Figure 10-2 presents a comparison of the winter peak demand forecasts. Note that the forecasts for the various scenarios and sensitivities were developed to reflect deviations based upon the base case winter peak demand forecast.
- Figure 10-3 presents a comparison of the annual net energy for load forecasts. Note that the forecasts for the various scenarios and sensitivities were developed to reflect deviations based upon the base case net energy for load forecast.
- Figure 10-4 presents a comparison of the natural gas price projections. Note that the high natural gas price projections were used for both the high natural gas sensitivity as well as the Green Economy scenario. As discussed in Section 7.0 of this IRP, the base case natural gas price projections were developed utilizing information from the United States Energy Information (EIA) Annual Energy Outlook 2018 (AEO 2018), and the high and low price sensitivities were developed based on sensitivity cases included in AEO2018.
- Figure 10-5 presents the annual carbon dioxide (CO_2) price projections considered in the Green Economy scenario. The CO_2 price projections were developed based on the CO_2 price projections contemplated in the Minnesota Public Utilities Commission Docket No. E-999/CI-14-643, *Order Updating Environmental Cost Values*, issued January 3, 2018.

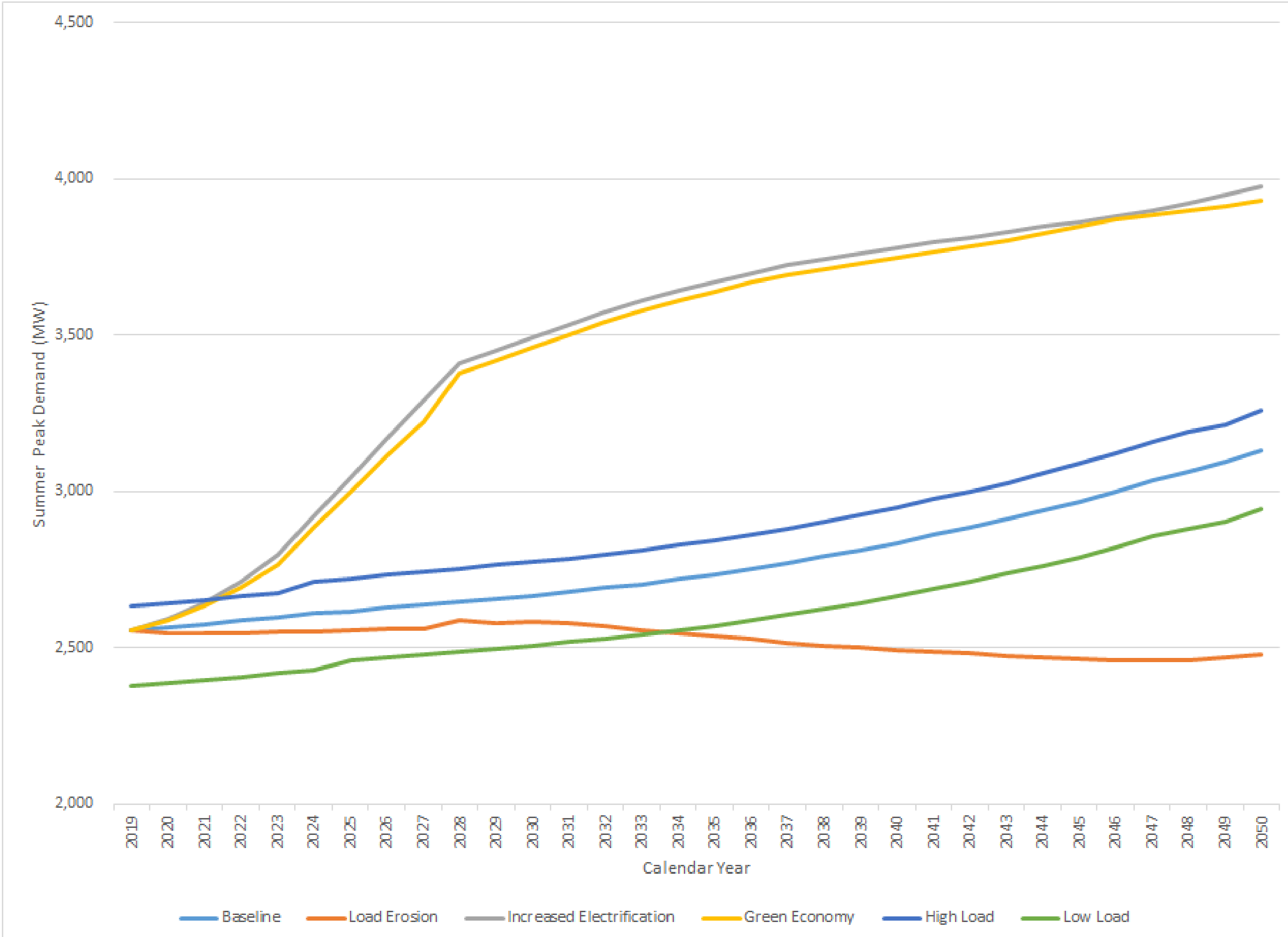

Figure 10-1
Comparison of Summer Peak Demand Forecasts

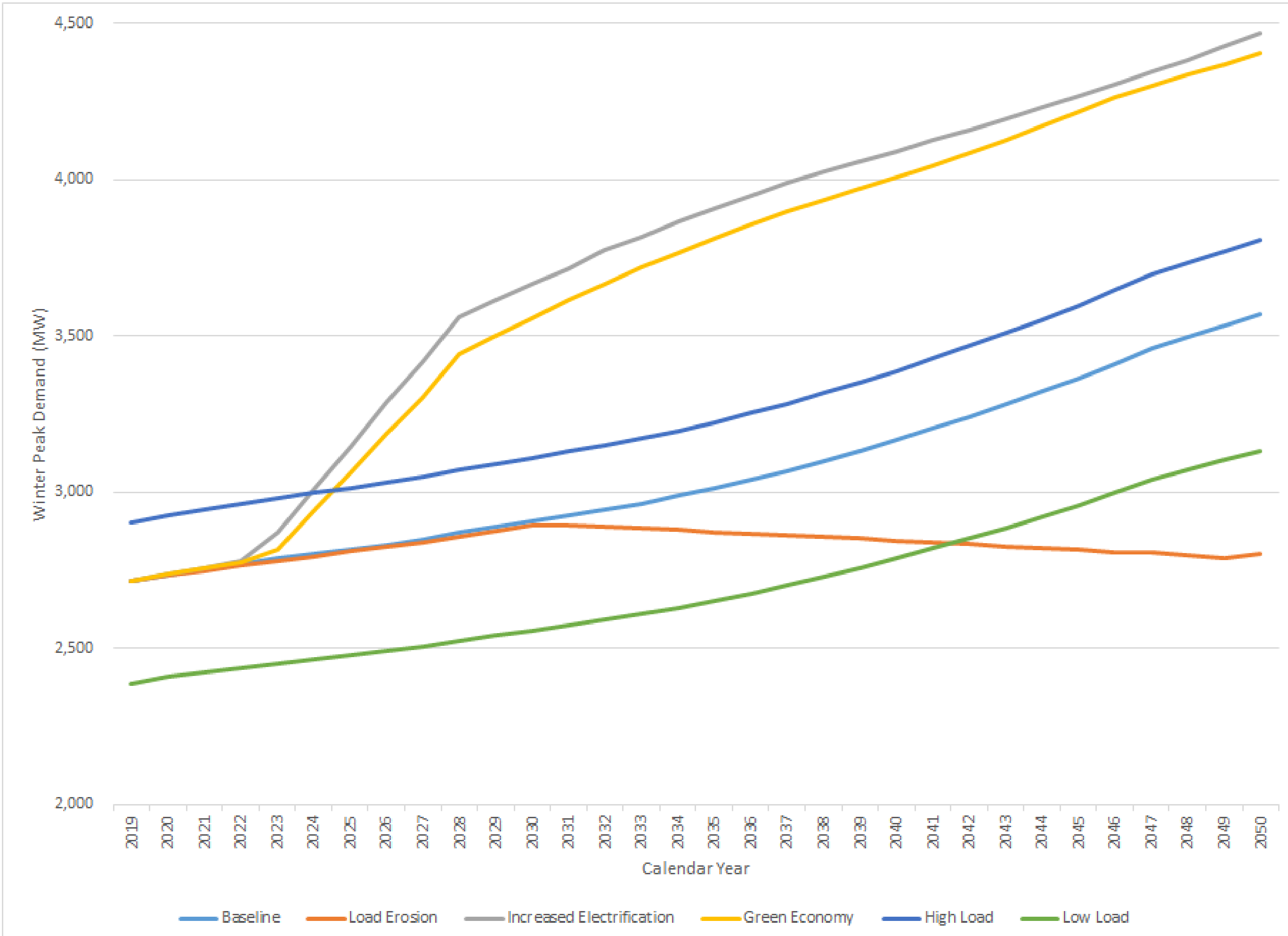

Figure 10-2
Comparison of Winter Peak Demand Forecasts

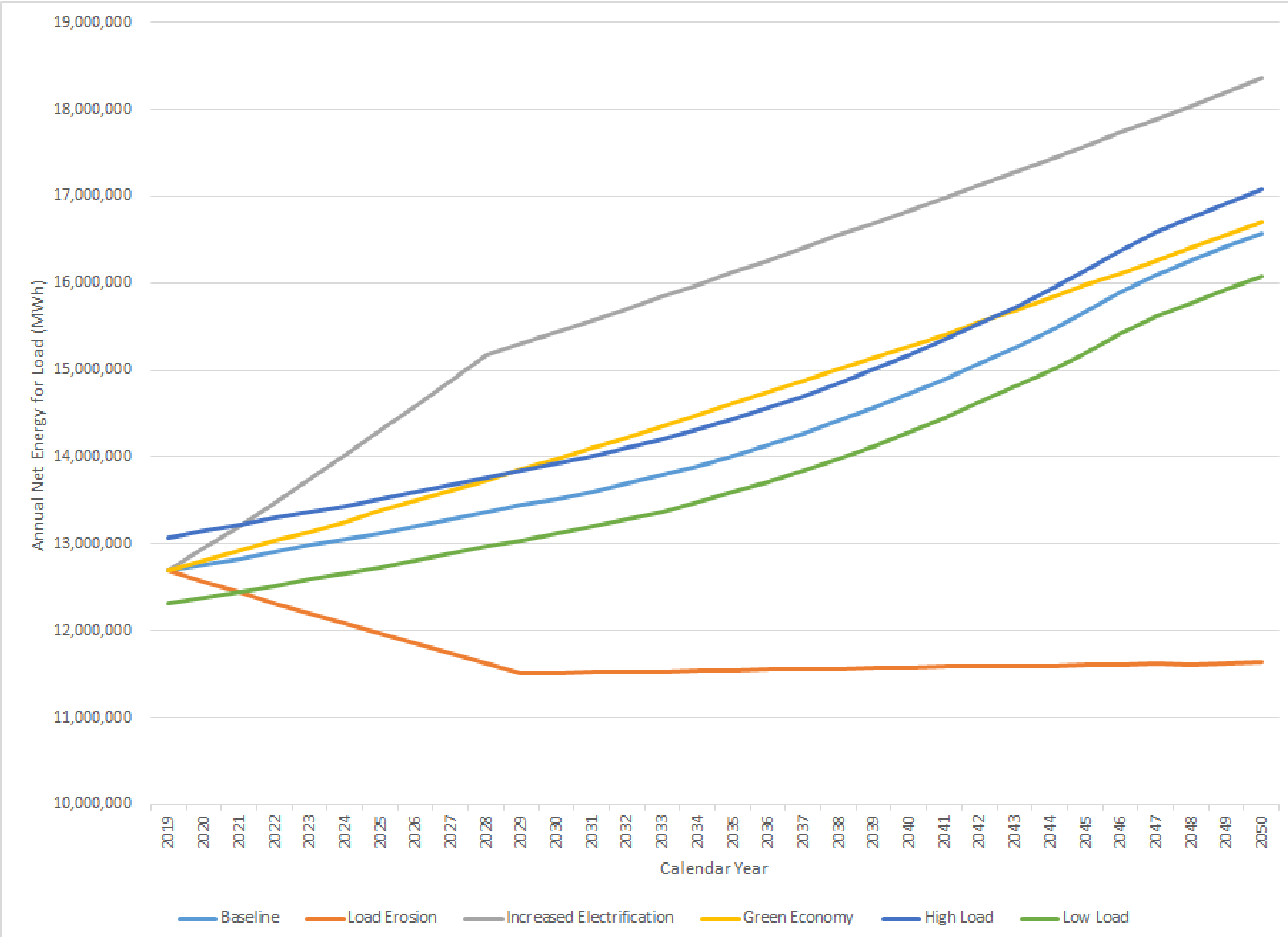

Figure 10-3
Comparison of Annual Net Energy for Load Forecasts

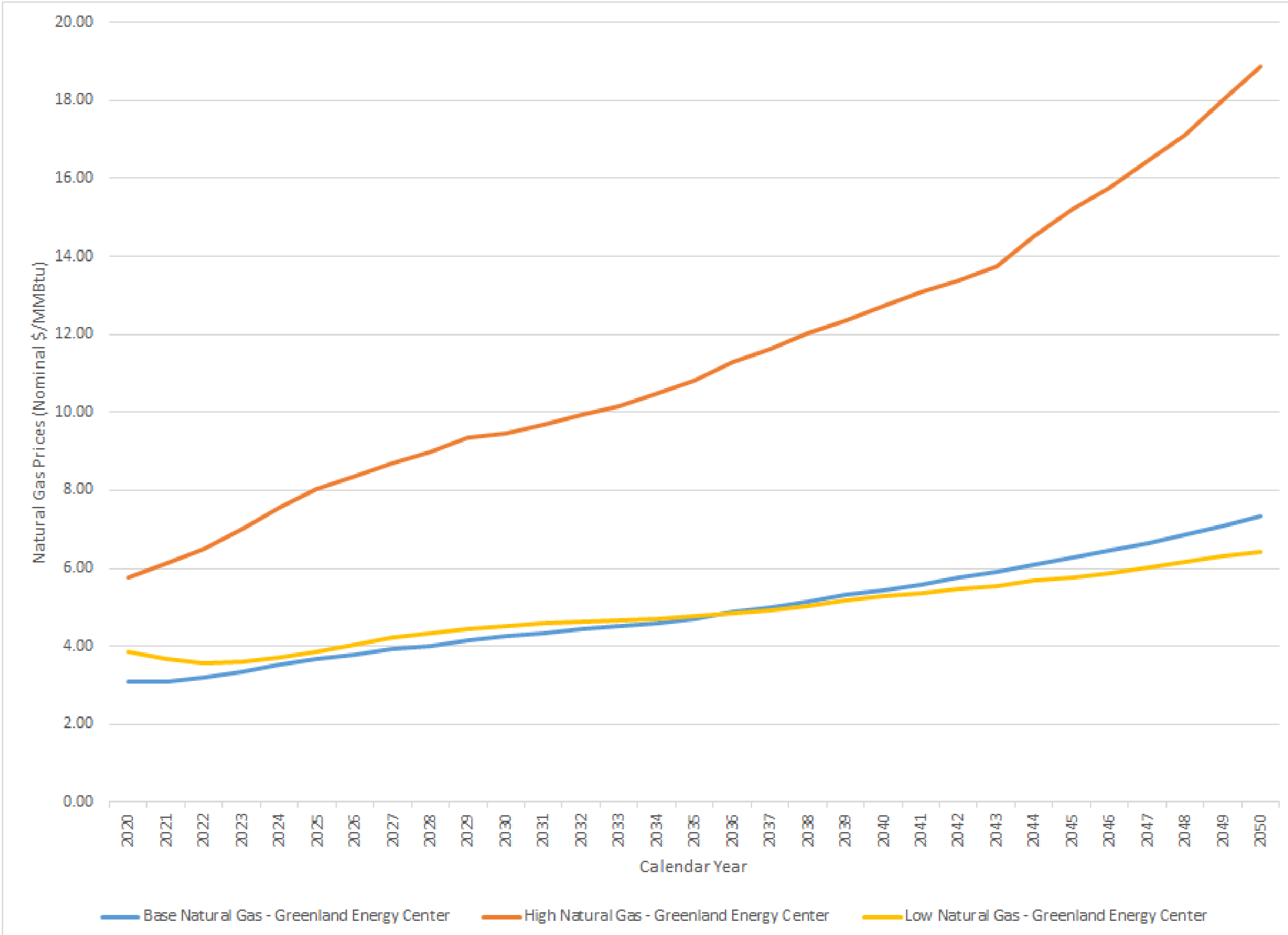

Figure 10-4
Comparison of Natural Gas Price Projections

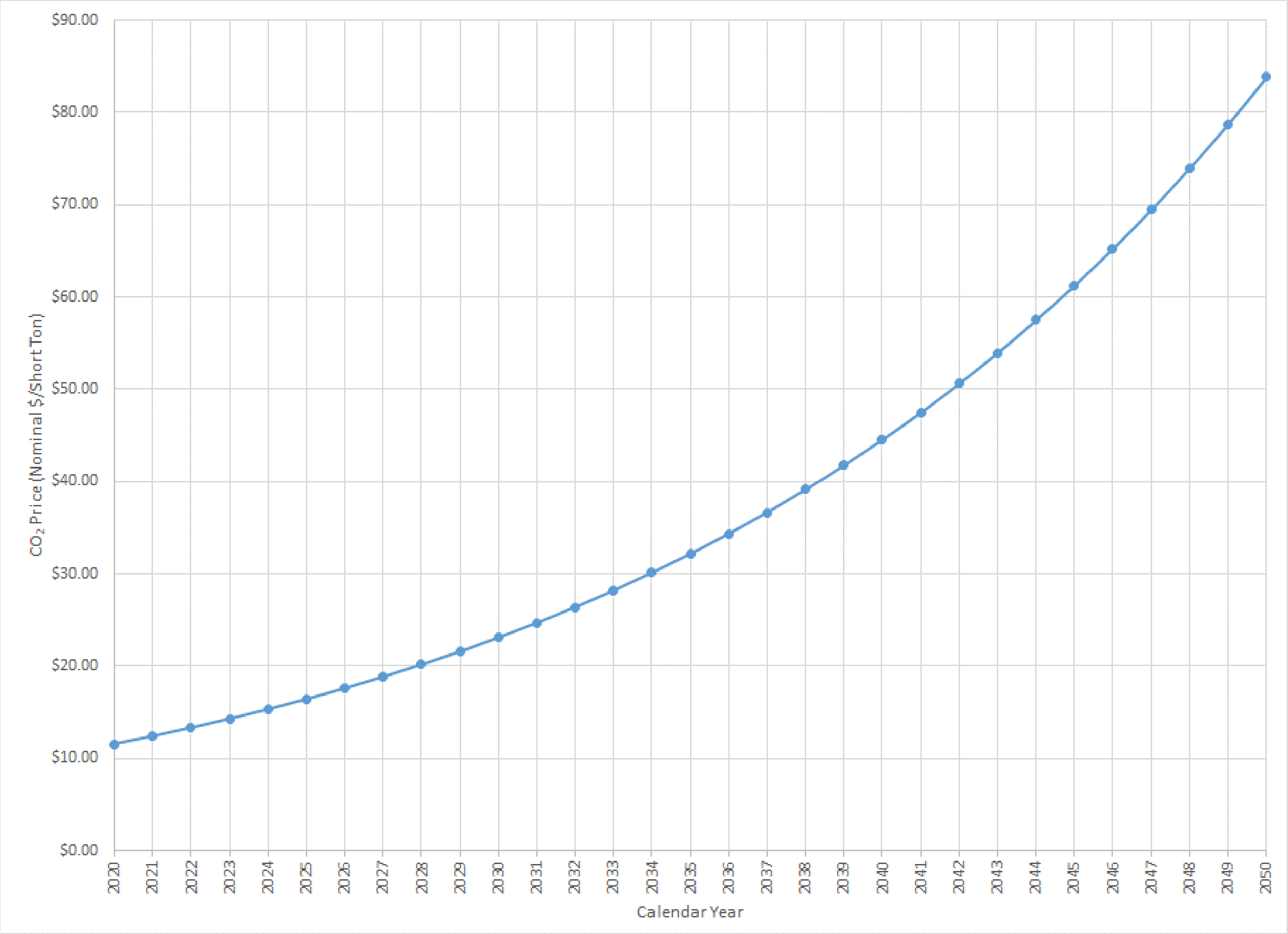

Figure 10-5
CO_2 Price Projections for Green Economy Scenario

10.2 Summary of Expansion Plans

The least-cost expansion plans determined using Strategist for each of the scenarios and sensitivities are summarized in the following subsections. For each scenario and sensitivity considered, a summary of the annual unit additions is presented in tabular format, followed by a graphical depiction of the CPWC that was developed based on the PROMOD production cost modeling. The CPWC is broken down by cost component, consisting of the following categories:

- “VOM”: System non-fuel variable O&M costs
- “Solar + Nuclear + Unserved Energy”: Costs for solar and nuclear generation (all costs for the nuclear PPAs have been modeled as generation costs) as well as any necessary market purchases required to meet generation requirements
- “Capital Costs”: Capital costs for new unit additions
- “Fixed O&M”: Fixed O&M costs for existing units and new unit additions
- “Fuel”: System fuel costs (i.e. natural gas, coal, petroleum coke)

10.2.1 Baseline Scenario

10.2.1.1 Base Load Forecast and Base Fuel Price Projections

Table 10-2 provides a summary of the annual generating unit additions included for various resource plans evaluated for the Baseline Scenario utilizing the base load forecast and base fuel price projections. Figure 10-1 presents the CPWC of each of these resource plans. The fundamental differences between the resource plans evaluated include assumptions related to continued operation of Northside 3 (the “Keep NS3” case), whether the Northside GTs are retired in 2029 (the “Retire NS3&NSGTs” case), combined cycle conversion of the existing GEC simple cycle units (the “Retire NS3 1x1GEC cnvrsn” and “Retire NS3 2x1GEC cnvrsn” cases), and a plan including retirement of Northside 3 without conversion of the existing GEC simple cycle units (the “Retire NS3 No GEC cnvrsn” case). Important to note is that the case in which Northside 3 does not retire includes $80 million (in 2018 dollars) to reflect estimated costs associated with 316(b) compliance costs as well as capital investment that may be necessary for Northside 3.

Table 10-2
Annual Generating Unit Additions – Baseline Scenario/Base Load Forecast and Base Fuel Price Projections

Year	Keep NS3	Retire NS3&NSCTs	Retire NS3 No GEC cnvrsn	Retire NS3 1x1GEC cnvrsn	Retire NS3 2x1 GEC cnvrsn
2025	7FA.05 SC	GEC 1x1 Conversion	7HA.02 1x1 CC	GEC 1x1 Conversion 7FA.05 SC	GEC 2x1 Conversion
2026		7HA.02 1x1 CC		7FA.05 SC	7HA.02 SC
2027			7FA.05 SC		
2028		7FA.05 SC			
2029					
2030					
2031					
2032					
2033					
2034					7FA.05 SC
2035					
2036		7FA.05 SC			
2037			7FA.05 SC	7FA.05 SC	
2038					
2039	7FA.05 SC		7FA.05 SC		
2040					
2041					7FA.05 SC
2042	7FA.05 1X1 CC	LMS100		7FA.05 1X1 CC	
2043		7FA.05 SC	7FA.05 SC		
2044					
2045					7FA.05 SC
2046		LMS100	7FA.05 SC	7FA.05 SC	
2047	7FA.05 SC				
2048		LMS100			
2049					
2050					Jenbacher 5xJ920

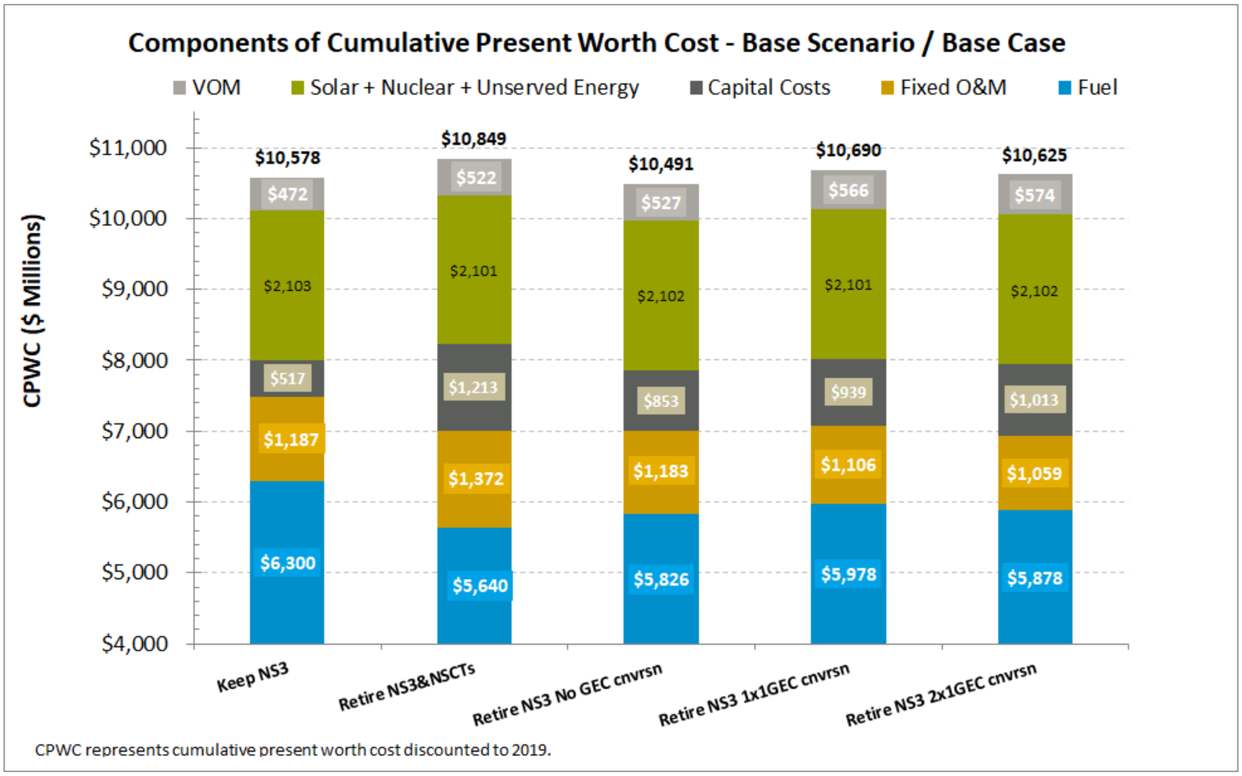

Figure 10-1

CPWC for Baseline Scenario/Base Load Forecast and Base Fuel Price Projections

10.2.1.2 High Load Forecast and Base Fuel Price Projections

Table 10-3 provides a summary of the annual generating unit additions included for various resource plans evaluated for the Baseline Scenario utilizing the high load forecast and base fuel price projections. Figure 10-2 presents the CPWC of each of these resource plans. The fundamental differences between the resource plans evaluated include assumptions related to continued operation of Northside 3 (the “Keep NS3” case), whether the Northside GTs are retired in 2029 (the “Retire NS3&NSGTs” case), combined cycle conversion of the existing GEC simple cycle units (the “Retire NS3 1x1GEC cnvrsn” and “Retire NS3 2x1GEC cnvrsn” cases), and a plan including retirement of Northside 3 without conversion of the existing GEC simple cycle units (the “Retire NS3 No GEC cnvrsn” case). Important to note is that the case in which Northside 3 does not retire includes $80 million (in 2018 dollars) to reflect estimated costs associated with 316(b) compliance costs as well as capital investment that may be necessary for Northside 3.

Table 10-3 Annual Generating Unit Additions – Baseline Scenario/High Load Forecast and Base Fuel Price Projections					
Year	Keep NS3	Retire NS3&NSCTs	Retire NS3 No GEC cnvrsn	Retire NS3 1x1GEC cnvrsn	Retire NS3 2x1 GEC cnvrsn
2025	7HA.02 1x1 CC	7HA.02 1x1 CC	7HA.02 1x1 CC	GEC 1x1 Conversion 7HA.02 SC	GEC 2x1 Conversion
2026		7FA.05 SC	7HA.02 SC	7HA.02 SC	7HA.02 SC 7FA.05 SC
2027					
2028					
2029		7HA.02 SC			
2030					
2031					
2032					
2033					
2034				7FA.05 SC	
2035					7FA.05 SC
2036		7FA.05 SC	7FA.05 SC		
2037					
2038					
2039			7FA.05 SC		
2040				7FA.05 1X1 CC	
2041	7HA.02 SC				7HA.02 SC
2042		7HA.02 SC	7HA.02 SC		
2043					
2044	7FA.05 SC			7FA.05 SC	7FA.05 SC
2045		7FA.05 SC	7FA.05 SC		
2046					
2047					
2048	LMS100			LMS100	LMS100
2049		Jenbacher 5xJ920			
2050			Jenbacher 5xJ920		

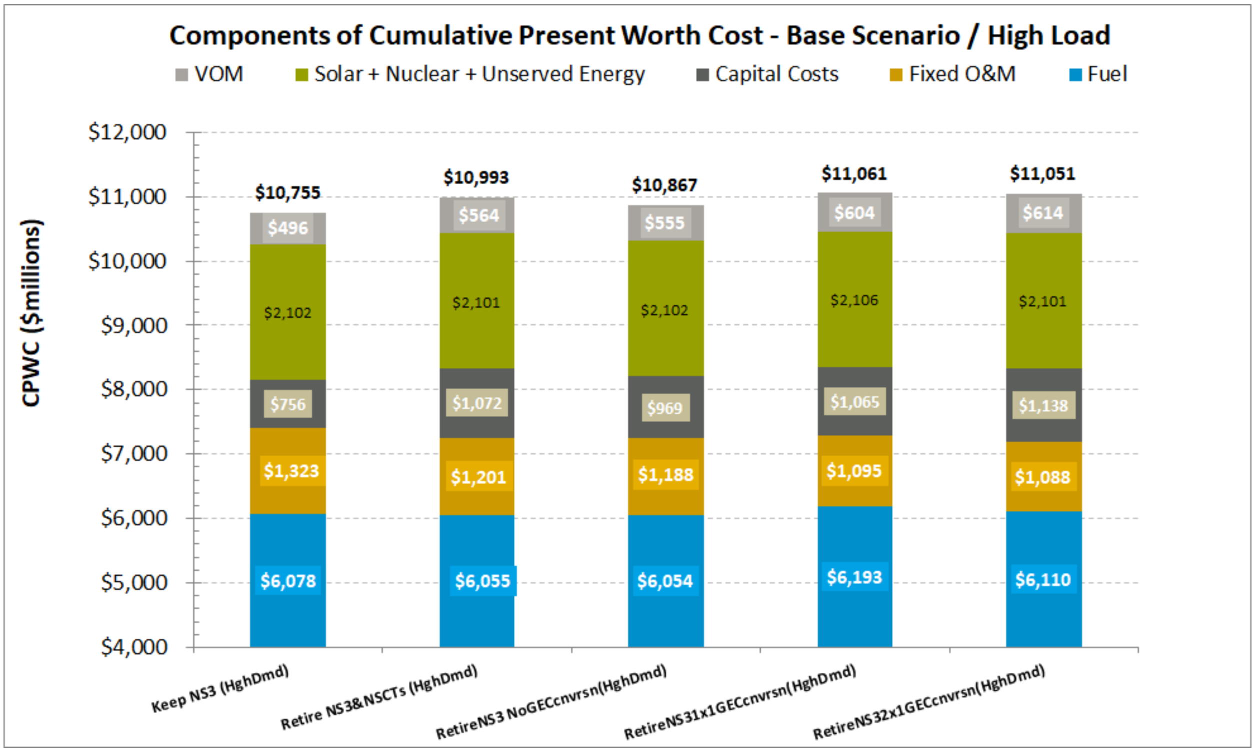

Figure 10-2

CPWC for Baseline Scenario/High Load Forecast and Base Fuel Price Projections

10.2.1.3 Low Load Forecast and Base Fuel Price Projections

Table 10-3 provides a summary of the annual generating unit additions included for various resource plans evaluated for the Baseline Scenario utilizing the low load forecast and base fuel price projections. Figure 10-2 presents the CPWC of each of these resource plans. The fundamental differences between the resource plans evaluated include assumptions related to continued operation of Northside 3 (the "Keep NS3" case), whether the Northside GTs are retired in 2029 (the "Retire NS3&NSGTs" case), combined cycle conversion of the existing GEC simple cycle units (the "Retire NS3 1x1GEC cnvrsn" and "Retire NS3 2x1GEC cnvrsn" cases), and a plan including retirement of Northside 3 without conversion of the existing GEC simple cycle units (the "Retire NS3 No GEC cnvrsn" case). Important to note is that the case in which Northside 3 does not retire includes $80 million (in 2018 dollars) to reflect estimated costs associated with 316(b) compliance costs as well as capital investment that may be necessary for Northside 3.

Table 10-4 Annual Generating Unit Additions – Baseline Scenario/Low Load Forecast and Base Fuel Price Projections					
Year	Keep NS3	Retire NS3&NSCTs	Retire NS3 No GEC cnvrsn	Retire NS3 1x1GEC cnvrsn	Retire NS3 2x1 GEC cnvrsn
2025				GEC 1x1 Conversion	GEC 2x1 Conversion
2026		7HA.02 1x1 CC	7HA.02 1x1 CC	7HA.02 SC	7FA.05 SC
2027					
2028					
2029		7FA.05 SC			
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037				7FA.05 SC	
2038					7FA.05 SC
2039		7FA.05 SC	7FA.05 SC		
2040	7FA.05 SC				
2041					
2042				7FA.05 1X1 CC	
2043	7FA.05 1x1 CC	7HA.02 SC	7FA.05 SC		7FA.05 SC
2044					
2045					
2046					7FA.05 SC
2047			7FA.05 SC		
2048				Jenbacher 5xJ920	
2049					
2050	Jenbacher 5xJ920	Jenbacher 5xJ920		Jenbacher 5xJ920	

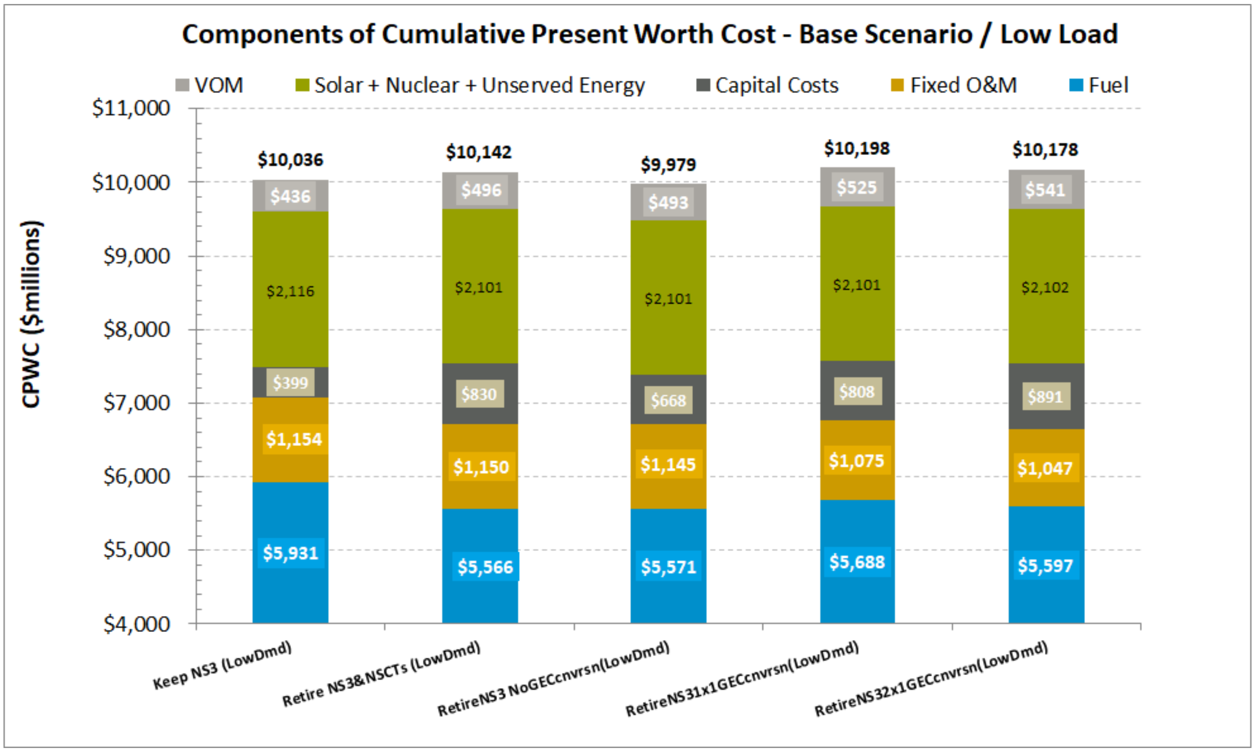

Figure 10-3

CPWC for Baseline Scenario/Low Load Forecast and Base Fuel Price Projections

10.2.1.4 Base Load Forecast and High Natural Gas Price Projections

Table 10-5 provides a summary of the annual generating unit additions included for various resource plans evaluated for the Baseline Scenario utilizing the base load forecast and high natural gas price projections. Figure 10-4 presents the CPWC of each of these resource plans. The fundamental differences between the resource plans evaluated include assumptions related to continued operation of Northside 3 (the "Keep NS3" case), whether the Northside GTs are retired in 2029 (the "Retire NS3&NSGTs" case), combined cycle conversion of the existing GEC simple cycle units (the "Retire NS3 1x1GEC cnvrsn" and "Retire NS3 2x1GEC cnvrsn" cases), and a plan including retirement of Northside 3 without conversion of the existing GEC simple cycle units (the "Retire NS3 No GEC cnvrsn" case). Important to note is that the case in which Northside 3 does not retire includes $80 million (in 2018 dollars) to reflect estimated costs associated with 316(b) compliance costs as well as capital investment that may be necessary for Northside 3.

Table 10-5 Annual Generating Unit Additions – Baseline Scenario/Base Load Forecast and High Natural Gas Price Projections					
Year	Keep NS3	Retire NS3&NSCTs	Retire NS3 No GEC cnvrsn	Retire NS3 1x1GEC cnvrsn	Retire NS3 2x1 GEC cnvrsn
2025	2x75 MW Solar PV	2x75 MW Solar PV 7HA.02 1x1 CC	2x75 MW Solar PV 7HA.02 1x1 CC	GEC 1x1 Conversion 2x75 MW Solar PV	GEC 2x1 Conversion 2x75 MW Solar PV
2026	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV 7HA.02 SC 7FA.05 SC	2x75 MW Solar PV 7HA.02 SC
2027	2x75 MW Solar PV	2x75 MW Solar PV 7HA.02 SC	2x75 MW Solar PV 7FA.05 SC	2x75 MW Solar PV	2x75 MW Solar PV
2028	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV
2029	2x75 MW Solar PV 7FA.05 SC	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV
2030	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV
2031	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV	2x75 MW Solar PV
2032	2x75 MW Solar PV	2x75 MW Solar PV		2x75 MW Solar PV	2x75 MW Solar PV
2033					
2034		7FA.05 SC			7FA.05 SC
2035			2x75 MW Solar PV		
2036					
2037				7FA.05 SC	
2038					
2039	7FA.05 SC		7FA.05 SC		
2040					
2041					7HA.02 SC
2042	7FA.05 1X1 CC	7FA.05 SC		7FA.05 1X1 CC	
2043		7FA.05 SC	7FA.05 SC		
2044					
2045					7FA.05 SC
2046			7FA.05 SC	7FA.05 SC	
2047	Jenbacher 5xJ920				
2048	7FA.05 SC	LMS100			
2049					
2050		Jenbacher 5xJ920			Jenbacher 5xJ920

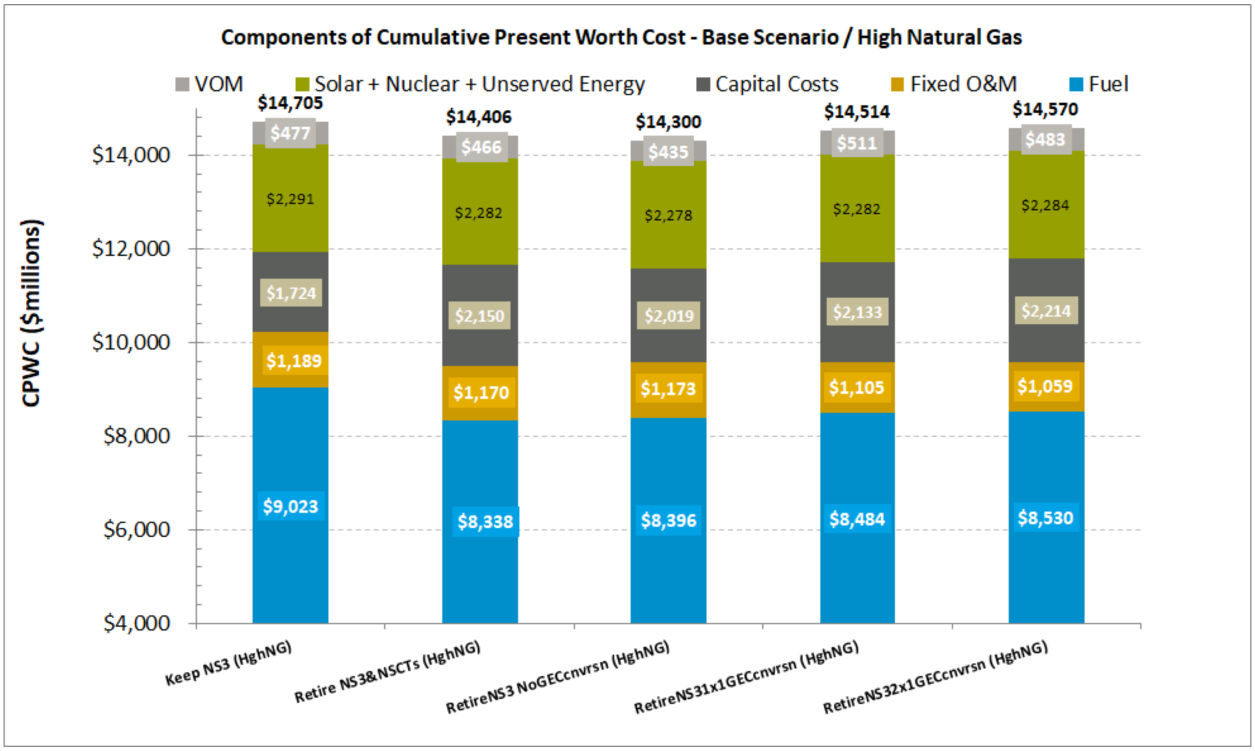

Figure 10-4

CPWC for Baseline Scenario/Base Load Forecast and High Natural Gas Price Projections

10.2.1.5 Base Load Forecast and Low Natural Gas Price Projections

Table 10-6 provides a summary of the annual generating unit additions included for various resource plans evaluated for the Baseline Scenario utilizing the base load forecast and low natural gas price projections. Figure 10-5 presents the CPWC of each of these resource plans. The fundamental differences between the resource plans evaluated include assumptions related to continued operation of Northside 3 (the “Keep NS3” case), whether the Northside GTs are retired in 2029 (the “Retire NS3&NSGTs” case), combined cycle conversion of the existing GEC simple cycle units (the “Retire NS3 1x1GEC cnvrsn” and “Retire NS3 2x1GEC cnvrsn” cases), and a plan including retirement of Northside 3 without conversion of the existing GEC simple cycle units (the “Retire NS3 No GEC cnvrsn” case). Important to note is that the case in which Northside 3 does not retire includes $80 million (in 2018 dollars) to reflect estimated costs associated with 316(b) compliance costs as well as capital investment that may be necessary for Northside 3.

Table 10-6 Annual Generating Unit Additions – Baseline Scenario/Base Load Forecast and Low Natural Gas Price Projections					
Year	Keep NS3	Retire NS3&NSCTs	Retire NS3 No GEC cnvrsn	Retire NS3 1x1GEC cnvrsn	Retire NS3 2x1 GEC cnvrsn
2025		7HA.02 1x1 CC	7HA.02 1x1 CC	GEC 1x1 Conversion	GEC 2x1 Conversion
2026				7HA.02 SC 7FA.05 SC	7HA.02 SC
2027		7HA.02 SC	7FA.05 SC		
2028					
2029	7FA.05 SC				
2030					
2031					
2032					
2033					
2034		7FA.05 SC			7FA.05 SC
2035					
2036					
2037				7FA.05 SC	
2038					
2039	7FA.05 SC		7FA.05 SC		
2040					
2041					7HA.02 SC
2042	7FA.05 1X1 CC	7HA.02 SC		7FA.05 1X1 CC	
2043			7FA.05 SC		
2044					
2045					7FA.05 SC
2046		7FA.05 SC	7FA.05 SC	7FA.05 SC	
2047	7FA.05 SC				
2048					
2049					
2050					Jenbacher 5xJ920

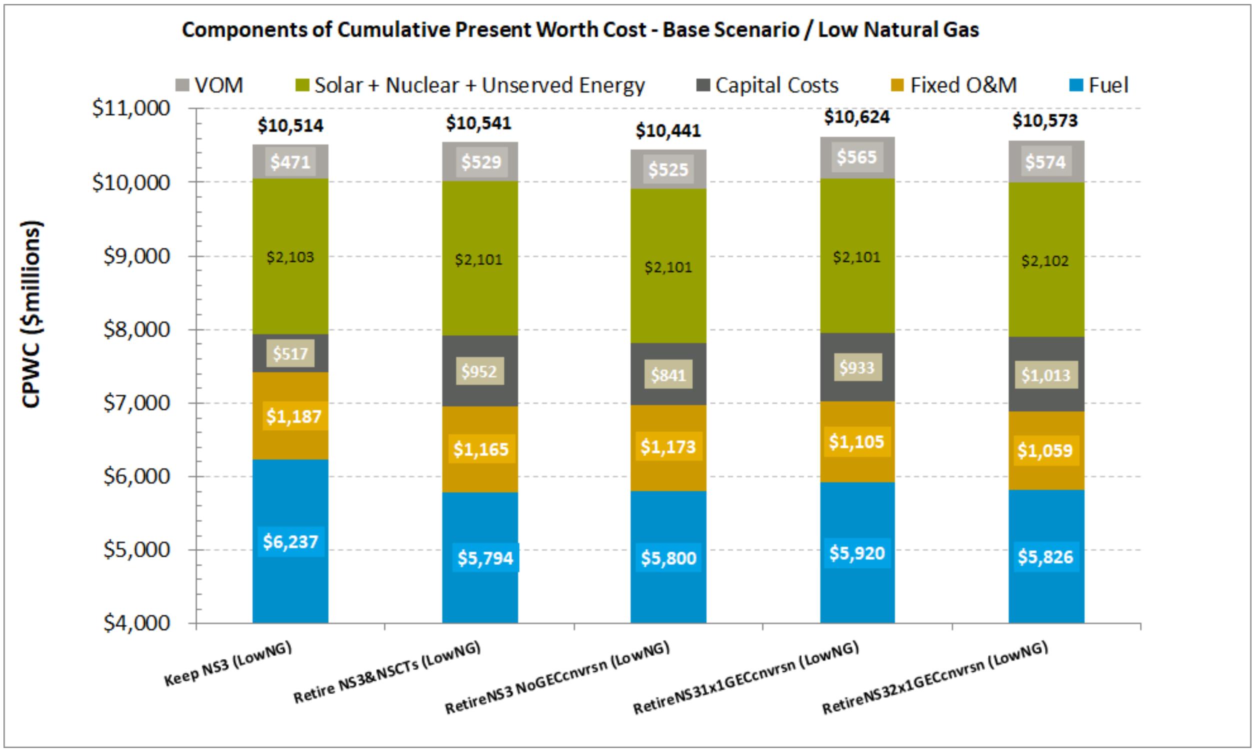

Figure 10-5

CPWC for Baseline Scenario/Base Load Forecast and High Natural Gas Price Projections

10.2.2 Load Erosion Scenario

Table 10-7 provides a summary of the annual generating unit additions included for various resource plans evaluated for the Load Erosion Scenario. Figure 10-6 presents the CPWC of each of these resource plans. The fundamental differences between the resource plans evaluated include assumptions related to continued operation of Northside 3 (the "Keep NS3" case), whether the Northside GTs are retired in 2029 (the "Retire NS3&NSGTs" case), combined cycle conversion of the existing GEC simple cycle units (the "Retire NS3 1x1GEC cnvrsn" and "Retire NS3 2x1GEC cnvrsn" cases), and a plan including retirement of Northside 3 without conversion of the existing GEC simple cycle units (the "Retire NS3 No GEC cnvrsn" case). Important to note is that the case in which Northside 3 does not retire includes $80 million (in 2018 dollars) to reflect estimated costs associated with 316(b) compliance costs as well as capital investment that may be necessary for Northside 3.

Table 10-7 Annual Generating Unit Additions – Load Erosion Scenario					
Year	Keep NS3	Retire NS3&NSCTs	Retire NS3 No GEC cnvrsn	Retire NS3 1x1GEC cnvrsn	Retire NS3 2x1 GEC cnvrsn
2025				GEC 1x1 Conversion	GEC 2x1 Conversion
2026		GEC 1x1 Conversion	7HA.02 1x1 CC		
2027					
2028					
2029		7FA.05 SC		7FA.05 SC	
2030					
2031	7FA.05 SC				
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					
2041					
2042		7FA.05 SC	7FA.05 SC		
2043					7FA.05 SC
2044					
2045					
2046					
2047					
2048					
2049					
2050					

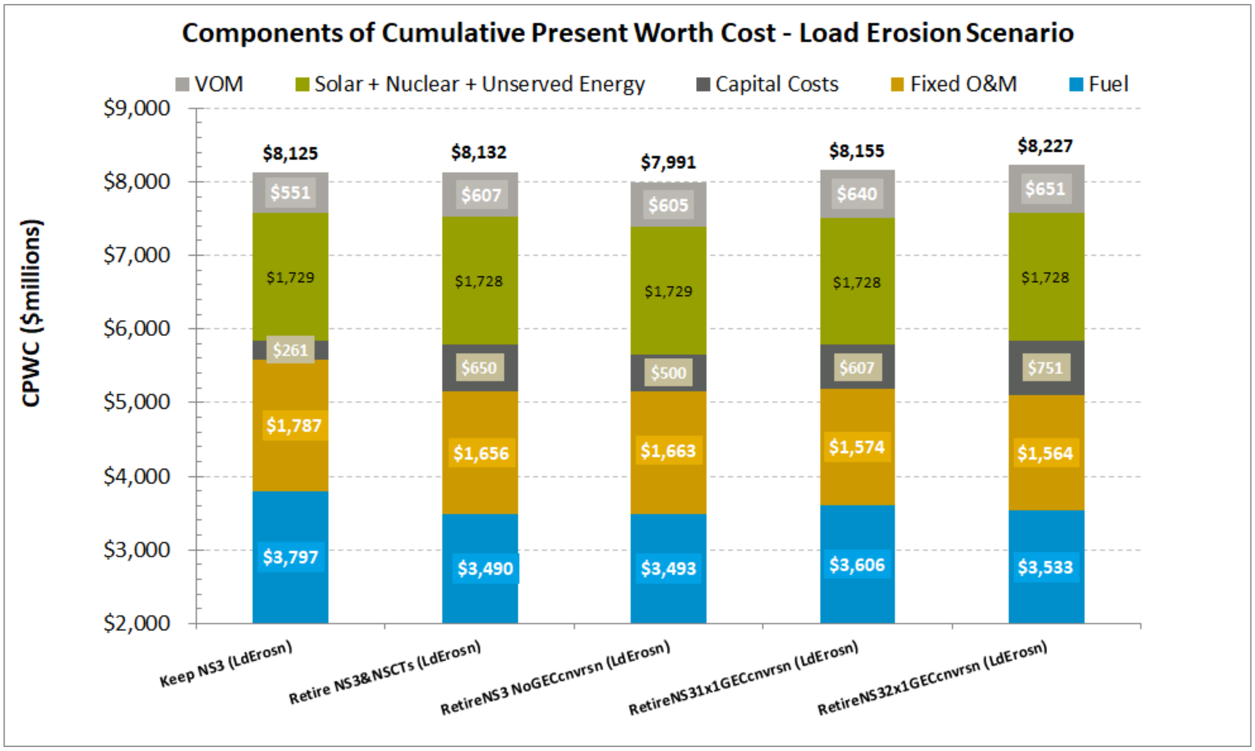

Figure 10-6

CPWC for Load Erosion Scenario

10.2.3 Increased Electrification Scenario

Table 10-8 provides a summary of the annual generating unit additions included for various resource plans evaluated for the Increased Electrification Scenario. Figure 10-7 presents the CPWC of each of these resource plans. The fundamental differences between the resource plans evaluated include assumptions related to continued operation of Northside 3 (the "Keep NS3" case), whether the Northside GTs are retired in 2029 (the "Retire NS3&NSGTs" case), combined cycle conversion of the existing GEC simple cycle units (the "Retire NS3 1x1GEC cnvrsn" and "Retire NS3 2x1GEC cnvrsn" cases), and a plan including retirement of Northside 3 without conversion of the existing GEC simple cycle units (the "Retire NS3 No GEC cnvrsn" case). Important to note is that the case in which Northside 3 does not retire includes $80 million (in 2018 dollars) to reflect estimated costs associated with 316(b) compliance costs as well as capital investment that may be necessary for Northside 3.

Table 10-8 Annual Generating Unit Additions – Increased Electrification Scenario					
Year	Keep NS3	Retire NS3&NSCTs	Retire NS3 No GEC cnvrsn	Retire NS3 1x1GEC cnvrsn	Retire NS3 2x1 GEC cnvrsn
2025	7HA.02 1x1 CC	7HA.02 1x1 CC	7HA.02 1x1 CC	GEC 1x1 Conversion 7HA.02 SC	GEC 2x1 Conversion 7HA.02 SC
2026	7HA.02 SC	2x7HA.02 SC	2x7HA.02 SC	2x7HA.02 SC 7FA.05 SC	2x7HA.02 SC
2027		7HA.02 SC	7HA.02 SC		7HA.02 SC
2028	7HA.02 SC				
2029		7HA.02 SC		7HA.02 1x1 CC	
2030			7FA.05 SC		
2031					7FA.05 SC
2032		7FA.05 SC			
2033					
2034	7FA.05 SC		7FA.05 SC		
2035					
2036					
2037		7FA.05 SC			7FA.05 SC
2038					
2039				7FA.05 SC	
2040					
2041					
2042	7HA.02 SC	7FA.05 SC	7FA.05 SC		7FA.05 SC
2043				7FA.05 SC	
2044					
2045					
2046					
2047	LMS100				LMS100
2048		LMS100	LMS100		
2049				LMS100	
2050	Jenbacher 5xJ920				Jenbacher 5xJ920

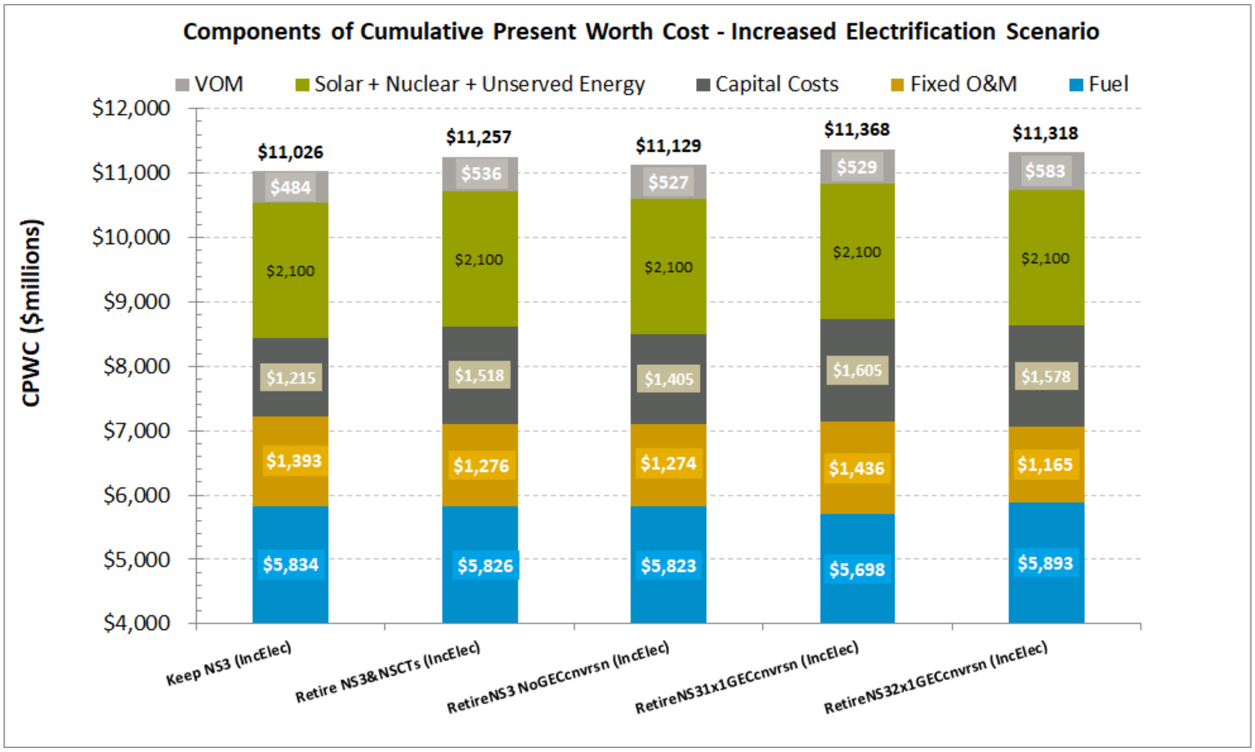

Figure 10-7

CPWC for Increased Electrification Scenario

10.2.4 Green Economy Scenario

Table 10-9 provides a summary of the annual generating unit additions included for various resource plans evaluated for the Green Economy Scenario. Figure 10-8 presents the CPWC of each of these resource plans. The fundamental differences between the resource plans evaluated include assumptions related to continued operation of Northside 3 (the “Keep NS3” case), whether the Northside GTs are retired in 2029 (the “Retire NS3&NSGTs” case), combined cycle conversion of the existing GEC simple cycle units (the “Retire NS3 1x1GEC cnvrsn” and “Retire NS3 2x1GEC cnvrsn” cases), and a plan including retirement of Northside 3 without conversion of the existing GEC simple cycle units (the “Retire NS3 No GEC cnvrsn” case). Important to note is that the case in which Northside 3 does not retire includes $80 million (in 2018 dollars) to reflect estimated costs associated with 316(b) compliance costs as well as capital investment that may be necessary for Northside 3.

Table 10-9 Annual Generating Unit Additions – Green Economy Scenario					
Year	Keep NS3	Retire NS3&NSCTs	Retire NS3 No GEC cnvrsn	Retire NS3 1x1GEC cnvrsn	Retire NS3 2x1 GEC cnvrsn
2025	GEC 1x1 Conversion 7HA.02 SC 2x75 MW Solar	GEC 1x1 Conversion 7HA.02 SC 2x75 MW Solar	7HA.02 1x1 CC 2x75 MW Solar	GEC 1x1 Conversion 7HA.02 SC 2x75 MW Solar	GEC 2x1 Conversion 7HA.02 SC 2x75 MW Solar
2026	7HA.02 SC 2x75 MW Solar	2x7HA.02 SC 2x75 MW Solar	2x7HA.02 SC 2x75 MW Solar	2x7HA.02 SC 2x75 MW Solar	2x7HA.02 SC 2x75 MW Solar
2027	2x75 MW Solar	7HA.02 SC 2x75 MW Solar	7HA.02 SC 2x75 MW Solar	7HA.02 SC 2x75 MW Solar	2x75 MW Solar
2028	7HA.02 SC 2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	7HA.02 SC 2x75 MW Solar
2029	2x75 MW Solar	7HA.02 1x1 CC 2x75 MW Solar	2x75 MW Solar	7HA.02 1x1 CC 2x75 MW Solar	2x75 MW Solar
2030	2x75 MW Solar	2x75 MW Solar	7FA.05 SC 2x75 MW Solar	2x75 MW Solar	2x75 MW Solar
2031	7HA.02 1x1 CC 7HA.02 SC 2x75 MW Solar	7HA.02 1x1 CC 7HA.02 SC LMS100 2x75 MW Solar	7HA.02 1x1 CC 7HA.02 SC 2x75 MW Solar	7FA.02 SC 7HA.02 SC 2x75 MW Solar	7HA.02 1x1 CC 7HA.02 SC 2x75 MW Solar
2032	2x75 MW Solar	7FA.05 SC 2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar
2033	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	7FA.05 SC 2x75 MW Solar
2034	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar
2035	7FA.05 SC 2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	7FA.05 SC 2x75 MW Solar	2x75 MW Solar
2036	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar
2037	2x75 MW Solar	2x75 MW Solar	7FA.05 SC 2x75 MW Solar	2x75 MW Solar	7FA.05 SC 2x75 MW Solar
2038	2x75 MW Solar	7FA.05 SC 2x75 MW Solar	2x75 MW Solar	2x75 MW Solar	2x75 MW Solar
2039					
2040					
2041					7FA.05 SC
2042	7HA.02 SC		7FA.05 SC	LMS100	
2043		7FA.05 SC		7FA.05 SC	7FA.05 SC
2044					
2045					
2046			LMS100		
2047					
2048		LMS100		LMS100	
2049	Jenbacher 5xJ920				
2050					Jenbacher 5xJ920

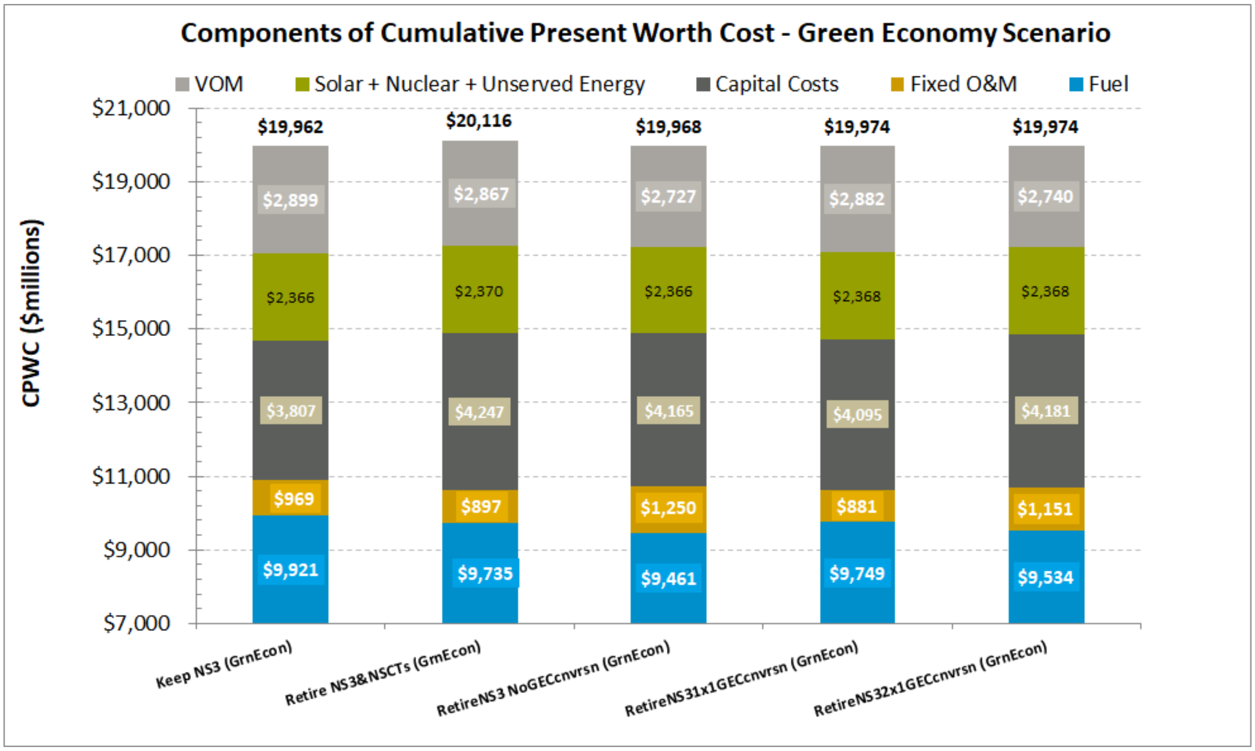

Figure 10-8

CPWC for Green Economy Scenario

11.0 CONCLUSIONS

This IRP provides a comprehensive analysis of various supply-side options that are appropriate for JEA to consider in order to continue to reliably meet its customers' demand for electricity in the most economic and environmentally responsible manner. Given JEA's projected capacity requirements, the focus of the IRP is on near-term resource decisions, with consideration of how those near-term decisions factor into JEA's long-term resource plans. As such, the scenario approach, supplemented by sensitivity analyses, provides for a comprehensive evaluation of resource decisions across a wide range of future outcomes related to evaluation factors that have the most significant impact on JEA's resource planning. Specifically, numerous variations to forecasts of annual peak demand and energy requirements (including the impact of demand-side management, energy efficiency, and solar net metering), natural gas price projections, environmental considerations (including potential carbon regulations and clean energy standards), continued operation of JEA's existing generating units, and costs for construction of new generating units.

Based on the evaluations performed for and discussed throughout this IRP, the following conclusions can be reached. Tables 11-1 and 11-2, presented at the end of this section, summarize the potential decisions and resource considerations within various timeframes and across the scenarios evaluated in this IRP.

- JEA's near-term capacity requirements are driven primarily by retirement of Northside 3, which is assumed to occur in September 2025. Given this assumption, a significant amount of new capacity is projected to be required in the 2025/26 timeframe in order to maintain JEA's reserve margin and meet capacity requirements.
- Specific to the Baseline Scenario and with the base load forecast and natural gas price projections, the following observations can be made:
    - The CPWC of the expansion plan that includes retirement of Northside 3 and a new 7HA.02 1x1 combined cycle in 2025 is the least cost expansion plan, but the other expansion plans are very close in CPWC.
        - The CPWC of the expansion plan with continued operation of Northside 3 is within 1 percent of the CPWC of the least cost expansion plan.
        - The CPWC of the expansion plan that includes conversion of both of the existing simple cycle combustion turbines at the Greenland Energy Center in 2025 is approximately 1.3 percent higher than the CPWC of the least-cost expansion plan.
        - The CPWC of the expansion plan that includes conversion of one of the existing simple cycle combustion turbines at the Greenland Energy Center in 2025 is approximately 1.9 percent higher than the CPWC of the least-cost expansion plan.
        - The CPWC of the expansion plan with Retirement of Northside 3 and the Northside simple cycle units is approximately 3.4 percent higher than the least cost expansion plan.
- In general, regardless of the scenario or sensitivity considered, the CPWCs of the various expansion plans are close to one another.
    - When comparing expansion plans including continued operation of Northside 3, retirement of Northside 3, and conversion of the Greenland Energy Center simple cycle units to combined cycle:
        - Comparisons of the CPWCs of expansion plans within each scenario and sensitivity indicates that the CPWCs of the expansion plans are within approximately 1 percent to 3 percent of one another.

        - The difference in CPWCs between expansion plans is often less than 1 percent.
        - Expansion plans that include retirement of Northside 3 and new combined cycles (i.e. either a new 1x1 combined cycle or conversion of one or both of the existing Greenland Energy Center simple cycle units to combined cycle) in the 2025/26 timeframe are generally lowest in CPWC; the differentials in CPWC between these plans is small.
- There are other important considerations beyond CPWC related to retirement or continued operation of Northside 3, including:
    - Safety
    - Performing a comprehensive condition assessment on Northside 3
    - Applicable regulations, including and other than 316(b)
    - Reliability (expected near-term and longer term)
    - Capital investment
    - Efficiency (qualitative consideration, as efficiency of the unit in terms of fuel usage and operating costs is reflected in the CPWC evaluations)
    - Operational flexibility, particularly when considering potential future integration of additional solar PV resources
- The IRP evaluated new solar PV resources, with and without storage, and reflecting the anticipated continued downward trend in solar pricing. Depending upon the scenario and sensitivity considered, it appears that additional solar may be beneficial and economic for JEA. However, before making final decisions about the amount and timing of new solar, and whether storage is appropriate, JEA should consider performing a solar integration study (such a study is beyond the scope of this IRP).
- As discussed throughout this section and supported by the evaluation results presented in Section 10 of this IRP, development of a new combined cycle for operation in 2025 appears to be cost-effective and appropriate for JEA. As such, JEA should consider the following:
    - Finalize decision on timing of Northside 3 retirement (see earlier bullet for relevant considerations).
    - Confirm whether a new combined cycle or combined cycle conversion of one or both of the existing Greenland Energy Center simple cycle units is to be pursued.
        - Develop more detailed project cost estimates for new 7HA.02 1x1 combined cycle (or similar, competing technology such as Siemens or Mitsubishi Hitachi Power Systems) and Greenland Energy Center combined cycle conversions.
        - Consider issuing a request for proposals (RFP) for comparable power supply alternatives.
        - Initiate activities to support developing and filing a determination of need, as a new combined cycle or conversion of the Greenland Energy Center simple cycle units would fall under the Florida Power Plant Siting Act (PPSA), as well as other necessary environmental permitting.
            - Development of a new power plant, expansion, repowering or conversion of an existing power plant, or addition of a new solar development with 75 MW or greater of steam capacity falls under the PPSA.

Table 11-1 Summary of Potential Resource Considerations

Timeframe	Natural Gas Resources	Solid-Fuel Resources	Nuclear Resources	Renewables	EE/DSM
Short-term (2020-2029)	• Potential Northside 3 retirement in September 2025; new combined cycle or combined cycle conversion in 2025/26 timeframe.	• No retirements or additions.	• 200 MW Vogtle 20-year PPA expected (100 MW beginning 2021; 100 MW beginning 2022).	• Continue to evaluate opportunities for additional solar (with and without storage). • IRP considered utility-scale solar (with and without storage). Economics of each may be expected to improve over the next several years. • JEA has recently committed to ~ 300 MW of solar; future evaluations of additional solar should consider ability to integrate with JEA's system (i.e. solar integration analysis).	• Continue with evaluations of new EE/DSM/Direct Load Control programs as appropriate for JEA's customers.
Mid–term (2030-2039) to Long-term (2040 – 2050)	• New simple cycle and/or new combined cycle capacity, depending on load growth, fuel prices, environmental regulations, etc.	• No solid fuel additions. • No solid fuel retirements under current environmental regulations; more stringent environmental regulations may necessitate retirement considerations. • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.	• New nuclear not considered as part of this IRP; consideration of future nuclear may be appropriate as Small Modular Reactor (SMR) technology matures.	• Continue to evaluate opportunities for additional solar (with and without storage). • IRP considered utility-scale solar (with and without storage). Economics of each may be expected to improve over the next several years. • JEA has recently committed to ~ 300 MW of solar; future evaluations of additional solar should consider ability to integrate with JEA's system (i.e. solar integration analysis).	• Continue with evaluations of new EE/DSM/Direct Load Control programs as appropriate for JEA's customers.

Table 11-2 Summary of Potential Resource Considerations by Scenario

Timeframe	Baseline Scenario	Load Erosion Scenario	Increased Electrification Scenario	Green Economy Scenario
Short-term (2020-2029)	• Decision on retirement of Northside 3 • Decision on new combined cycle resource (i.e. conversion of GEC simple cycle unit(s) or new 1x1 combined cycle) • Consideration of additional utility-scale solar PV (solar integration study recommended)	• Decision on retirement of Northside 3 • Decision on new combined cycle resource (i.e. conversion of GEC simple cycle unit(s) or new 1x1 combined cycle) • Consideration of additional utility-scale solar PV (solar integration study recommended)	• Decision on retirement of Northside 3 • Decision on new combined cycle resource (i.e. conversion of GEC simple cycle unit(s) or new 1x1 combined cycle) • Consideration of additional utility-scale solar PV (solar integration study recommended)	• Decision on retirement of Northside 3 • Decision on new combined cycle resource (i.e. conversion of GEC simple cycle unit(s) or new 1x1 combined cycle) • Consideration of additional utility-scale solar PV (solar integration study recommended) • No solid fuel retirements under current environmental regulations; more stringent environmental regulations may necessitate retirement considerations
Mid–term (2030-2039) to Long-term (2040 – 2050)	• Decision on new simple cycle resources. • Consideration of additional utility-scale solar PV (solar integration study recommended) • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.	• Decision on new simple cycle resources. • Consideration of additional utility-scale solar PV (solar integration study recommended) • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.	• Decision on new simple cycle resources. • Consideration of additional utility-scale solar PV (solar integration study recommended) • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.	• Decision on new simple cycle resources. • Consideration of additional utility-scale solar PV (solar integration study recommended) • Continue to evaluate reliability/safety considerations as solid fuel units approach end of projected useful lives.

APPENDIX A. ENVIRONMENTAL ASSESSMENT

1.0 Environmental Considerations

JEA's generation fleet is subject to numerous environmental regulatory programs and requirements. While most of the environmental regulatory programs and requirements applicable to JEA generating units have already been addressed, a few recently proposed and finalized programs in various stages of administrative transition and judicial review could have impacts on future operations.[1] The following sections provide a summary of the applicability of air, water and waste programs and permitting requirements, as well as the associated potential compliance risks associated with continued operation of the existing fossil fuel-fired generating units.

1.1 AIR QUALITY AND EMISSIONS REGULATIONS

The following subsection outlines the current and impending regulatory programs and requirements related to air pollutant emissions from the JEA generation units.

1.1.1 New Source Review & Title V Air Operation Permits

Federal and State regulations require that an air construction permit be obtained to authorize construction of new emissions units or modifications to existing emissions units. The construction permitting process entails New Source Review (NSR), which begins with an analysis to determine the applicability of major source permitting requirements under the provisions of Prevention of Significant Deterioration (PSD), for those sources located in areas that are in attainment of the National Ambient Air Quality Standards (NAAQS) or unclassifiable, or Non-Attainment NSR (NA NSR) for those sources located in areas not in attainment of the NAAQS for one or more pollutants. Duval County, Florida, where all of JEA's generating assets in Florida are situated, is currently designated as attainment or unclassifiable for all criteria pollutants. However, Nassau County, Florida, which is immediately north of Duval County, is currently designated as non-attainment for the 1-hr sulfur dioxide (SO_2) NAAQS. Compliance with the various NAAQS is determined on an annual basis, and as such, the attainment status of a given county is certainly subject to change in the future.

Should JEA undertake any installations/modifications in the future that trigger PSD and/or NA NSR (i.e., major source permitting),[2] a construction permit will first need to be obtained. EPA has recently proposed changes to how NSR applicability is determined for major modifications (see subsequent discussion under Clean Power Plan/Affordable Clean Energy)

Air permitting in Florida is under the jurisdiction of the Florida Department of Environmental Protection (FDEP). The USEPA has given the FDEP authority to implement and enforce the federal

[1] This document was prepared beginning in 2018 to support an Integrated Resource Plan (IRP). With the delay in draft completion of the IRP, some of the regulatory actions documented as in progress, particularly the CPP and the ACE rule, have now been finalized. This document has not been updated to reflect current regulatory conditions.

[2] Major source permitting would be required for construction of a new emission source (i.e. installation of a new unit) and/or modification of an existing emission source (upgrade of existing unit) that would result in both a significant emission increase and a significant net emission increase of at least one PSD pollutant. Determining whether a significant emission increase and significant net emission increase occur is done by comparing the projected emissions attributable to the project and any emissions increases/decreases within a contemporaneous period to the applicable PSD major source thresholds and/or significant emission rates (SERs)(40 CFR 52.21 and 62-210.200, F.A.C.).

Clean Air Act (CAA) provisions and state air regulations under its approved State Implementation Plan (SIP). In Georgia, the Georgia Department of Natural Resources (GA DNR) Environmental Protection Division (EPD) is the permitting authority under the CAA.

Each of the currently operating JEA generation assets is authorized by a Title V Air Operation Permit. These permits establish terms and conditions which the permitted facility must operate under, including operational requirements/restrictions, monitoring and reporting requirements, and emission limits. JEA maintains compliance with the terms and conditions of their various Title V Air Operation Permits. Additionally, the current terms and conditions do not present any significant risks of non-compliance or necessity to incur additional costs to maintain compliance in the future.

Concurrent with Northside Generating Station (NGS) Units 1 and 2 being converted to circulating fluidized bed (CFB) boilers, JEA entered into a Community Commitment to reduce overall SO_2, nitrogen oxides (NO_X), and particulate matter (PM) emissions from Units 1, 2, and 3 by 10 percent relative to previous annual emissions. These limits, which are now included in the NGS Title V Air Operation Permit are listed in Table 1-1 below.

Table 1-1 Northside Generating Station Community Commitment Emission Limits

POLLUTANT	CUMULATIVE ANNUAL LIMIT – UNITS 1, 2, AND 3 (TPY)
NO_X	3,600
SO_2	12,284
PM	881

Based on the current operation of NGS Units 1 2, and 3, the SO_2 and PM limits are easily met. The annual NO_X limit requires more careful management to ensure compliance. Based on facility NO_X CEMS data from 2013-2017, annual NO_X emissions have been well within the prescribed limit. This data and the annual operating hours of each unit is included in Table 1-2 on the following page.

Assuming future operation remains consistent with recent past operation, these emission limits should have no impact on operations at NGS. However, should market conditions dictate increased dispatch of the units in the future, operations (including the use of the existing selective non-catalytic reduction systems on NGS Units 1 and 2), will need to be managed carefully in order to maintain compliance with the annual NO_X emission limit.

Table 1-2 Annual Facility Total NOX Emissions and Hours of Operation for Northside Generating Station

YEAR	ANNUAL NO_X EMISSIONS (UNITS 1, 2, & 3 COMBINED)		ANNUAL HOURS OF OPERATION	% OF FULL YEAR
2013	1,009	Unit 1	5,933	68
		Unit 2	4,717	54
		Unit 3	3,008	34
2014	1,528	Unit 1	7,547	86
		Unit 2	7,127	81
		Unit 3	3,164	36
2015	1,967	Unit 1	6,720	77
		Unit 2	5,743	66
		Unit 3	5,207	59
2016	2,555	Unit 1	6,312	72
		Unit 2	7,780	89
		Unit 3	5,857	67
2017	1,923	Unit 1	4,762	54
		Unit 2	3,239	37
		Unit 3	5,025	57

1.1.2 National Ambient Air Quality Standards

The EPA has set National Ambient Air Quality Standards (NAAQS) for six principal pollutants, which are called "criteria" air pollutants. Geographical areas (in this case counties) in Florida are designated for each pollutant as attainment, non-attainment, or unclassifiable based on actual air quality measurements and/or modeling. As noted above, currently, Duval County Florida is designated as attainment or unclassifiable for all the criteria pollutants. It is expected that the most recent unclassifiable designation for the 2015 ozone standard will be revised to attainment once the monitoring data is validated.

The CAA requires that EPA periodically review the various NAAQS and promulgate revised standards if scientific evidence indicates that a revision is necessary. In 2010, EPA established new 1-hour standards for SO_2 and NO_x which has presented compliance challenges as a result of the short (one hour) averaging period. Of specific concern, the 1-hour SO_2 NAAQS Data Requirements Rule (DRR) required states to either monitor ambient air or conduct air dispersion modeling to demonstrate compliance with 1-hour SO_2 NAAQS. Again, while Duval County is designated as attainment/unclassifiable for the 1-hour SO_2 and NO_X NAAQS, Nassau County is designated as non-attainment for the 1-hour SO_2 NAAQS[3].

[3] FDEP submitted a proposed revision to the state's SIP on June 7, 2018 requesting a re-designation of Nassau County to attainment for the 2010 1-hr SO_2 NAAQS.

In order to proactively ensure compliance with the 1-hr SO2 NAAQS violations, JEA has implemented operating restrictions on NGS Unit 3 that apply to oil-fired operations. Future revisions to these standards to make them more stringent could potentially change the attainment designation of Duval and/or surrounding Counties, which could further impact the operation of the JEA fleet should FDEP take steps to mitigate short term NO_X and/or SO_2 emissions from fossil fuel-fired electric generating facilities.

In 2015 EPA finalized an 8-hour standard of 70 parts per billion (ppb) for ozone. EPA finalized area designations throughout the country in April 2018. Duval County, Florida, including Jacksonville, is currently designated as unclassifiable for the 2015 ozone standard due to monitoring data for the 2014-2016 period that was shown to be invalid. According to EPA documentation, EPA's current unclassifiable designation will change pending FDEP's submittal of a valid, quality assured data set capturing three years of monitoring data. Based on FDEP's 2018 Annual Air Network Monitoring Plan, the 2015-2017 monitoring data from Duval County is also incomplete. It is understood that complete 2016-2018 monitoring results data should be available and submitted by April of 2019, and thereafter, a re-designation from unclassifiable to attainment is anticipated.

1.1.3 Acid Rain Program

The Acid Rain Program (ARP) is aimed at achieving major emission reductions of SO_2 and NO_X, the primary precursors of acid rain. NO_X reductions are achieved by imposing emission limits on various types of coal-fired boilers regulated under the ARP. SO_2 reductions, on the other hand, are achieved via a cap-and-trade program. Regulated emission units (i.e., fossil fuel-fired combustion devices that serve a generator capable of producing 25 MW of electricity for sale to the grid) are required to surrender allowances for each ton of SO_2 emitted annually.

JEA will continue to be required to surrender ARP allowances to cover the units' ARP compliance obligation into the future. Regulated units that were constructed prior to 2001 are allocated allowances annually. Sources constructed after 2001 are not provided an allocation of allowances, and must purchase them from government accounts, auctions and/or the open market. Compliance obligations over and above annual allocations can either be covered by banked allowances in owner-held accounts or obtained from the open market. JEA's current compliance strategy is to rely on banked allowances to cover the fleet's annual compliance obligation. ARP allowances are currently trading at less than $1 per ton. Assuming that allowance prices don't increase dramatically, in the event that JEA is required to obtain at least a portion of its ARP compliance obligation in the future, it should not represent a significant operational cost.

1.1.4 Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) is EPA's cap and trade program aimed at curbing cross-state transport of NO_x and SO_2 emissions in the eastern United States. Ultimately, the purpose of the rule is to reduce the number of $PM_{2.5}$ and ozone nonattainment areas caused by cross-state air pollution from the power sector. Affected units under CSAPR are required to surrender allowances for both annual NO_x and SO_2 emissions and/or ozone season (May through September) NO_x emissions. For each affected unit, a given state allocates allowances for each regulated pollutant and compliance period. Any surplus allowances can be banked and held for future compliance and/or sold on the open market. Should a facility's emissions be in excess of its annual allocation, the deficit is required to be covered by banked allowances and/or allowances purchased on the open market.

As originally designed, CSAPR was intended to reduce NO_X emissions in order to help achieve attainment of the 1997 ozone standard. EPA issued an update to CSAPR in 2016 to incorporate the more stringent 2008 ozone standard. This update removed Florida from the requirement to participate in the ozone season NO_X emissions program. As such, facilities in Florida are no longer required to participate in CSAPR.

Facilities in Georgia, on the other hand, are required to participate in both the annual SO_2 and NO_X programs, as well as the seasonal (ozone season) NO_X program. Therefore, Scherer Unit 4 has a compliance obligation under CSAPR. Scherer Unit 4 is allocated 9,930 tons and 3,794 tons of annual SO_2 and annual NO_X allowances, respectively. For ozone season NO_X, Scherer Unit 4 is allocated 657 tons per year.

In 2018, seasonal CSAPR NO_X allowances are trading for approximately $250 per ton while annual NO_X allowances are trading for approximately $2.10 per ton. SO_2 allowances are trading for approximately $2.30 per ton. While market forces will result in some variability in allowance pricing over time, annual allowance prices have remained stable while only the seasonal NOx prices have varied by as much as twice (higher and lower) over the past 3 years.

1.1.5 Greenhouse Gas Regulations for Existing Power Plants

Clean Power Plan

On August 3, 2015 the USEPA released its final Clean Power Plan (CPP) rulemaking to establish standards for performance for greenhouse gas emissions from existing electric generating units (EGUs) (i.e., EGUs for which construction was commenced prior to January 8, 2014) under Section 111(d) of the CAA. In the final CPP rule, the USEPA set emission performance rates, phased in over the period from 2022 through 2030, for two subcategories of affected fossil fuel-fired EGUs – fossil fuel-fired electric utility steam generating units and stationary combustion turbines.

In setting these performance standards, the USEPA identified three specific measures they call “building blocks” that represent the Best System of Emissions Reduction (BSER). The three building blocks were:

1. Improving heat rate at affected coal-fired steam EGUs.
2. Substituting increased generation from lower emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units.
3. Substituting increased generation from new zero emitting renewable energy generating capacity for reduced generation from affected fossil fuel-fired generating units.

The USEPA developed specific emission performance rates for fossil-fuel steam generation and combustion turbines by considering the above building blocks.

Under the CPP, each state was required to determine whether to apply these rates directly to each affected EGU or to take an alternative approach and meet either an equivalent statewide rate-based goal or statewide mass-based goal. To develop equivalent statewide rate-based goals or statewide mass-based goals, the USEPA applied these rates to each state's particular mix of fossil fuel-fired EGUs. This allowed the agency to generate each state's carbon intensity goal. These emission rates would not have necessarily been applied to each source as an in-stack limit. Rather, states and sources would have flexibility in how they meet the goals. The final rate-based goal for Florida was set at 1,176 lbs. CO_2/MWh.

The final CPP rule required each state to submit a final plan that outlines how the state will meet its goal by September 2016. However, on February 9, 2016 the United States Supreme Court issued an order to stay (suspend) the CPP until legal challenges to the rule could be resolved in federal court(s). In September of 2016, the D.C. Circuit Court of Appeals heard oral arguments on the legal challenges to the CPP. Following the hearings, however, the D.C. Circuit subsequently granted a petition from the new Trump Administration to hold the prior CPP litigation in abeyance pending the outcome of EPA's announced intentions to reconsider the CPP rule.

EPA Reconsideration Rulemakings

EPA published a proposal to repeal the CPP in its entirety on October 16, 2017. Then on August 21, 2018 EPA released an alternative proposal to revise the CPP. Entitled the Affordable Clean Energy (ACE) rule, this latest proposal seeks to reduce CO_2 emissions solely through heat rate improvements at existing fossil fuel-fired utility boiler EGUs. Units 1, 2, and 3 at Northside Generating Station and Scherer Unit 4 are the only units in JEA's portfolio that would be subject to regulation under ACE as currently proposed.

As with the CPP, the ACE proposes to regulate existing power plants under Section 111(d) of the CAA by establishing performance standards based on BSER. In contrast to the CPP, however, and in accordance with EPA's most recent interpretation of its authority under the CAA, ACE focuses on only those measures that can be implemented "within the fenceline" of existing EGU facilities. Consistent with that approach, EPA has proposed that BSER is to be limited to heat rate improvement measures at existing coal-fired EGUs. Instead of setting numeric limits, EPA's proposed ACE rule would provide emission guidelines that states could use in developing their individual SIPs to regulate CO_2 emissions from EGUs within their jurisdictions. These guidelines would include a list of "candidate technologies" and measures to achieve heat rate improvements.

Table 1-3 Affordable Clean Energy Rule

CANDIDATE TECHNOLOGIES
Neural Networks and Intelligent Soot Blowers
Boiler Feed Pump Reliability and Efficiency
Air Heater and Duct Leakage Control Improvements
Variable Frequency Drives on ID Fans and Boiler Feed Pumps
Steam Turbine/Blade Path Upgrades
Redesign or Replacement of Economizer
Improved O&M Practices (Training, Appraisals, Cleaning, and Maintenance)

The specific emission limits and requirements that each affected EGU must meet will ultimately be established by the state where the unit is located. States are afforded considerable flexibility in determining emission standards for units. States are to use the ACE emission guidelines to evaluate what heat rate improvements are appropriate and feasible for each individual existing affected EGU within the state. States will also have discretion to consider factors beyond those outlined in EPA's emissions guidelines – which may include non-BSER technologies, operational measures and strategies, as well as the remaining useful life of the facility. ACE also allows for states to use emissions averaging across units within the same power plant facility. Ultimately, the state must establish a unit-specific performance standard expressed in pounds of CO_2 per megawatt-hour (gross) (lb CO_2/MW-hr).

States will also determine compliance deadlines for each EGU, as well as the monitoring, averaging periods, and recordkeeping and reporting requirements. The standards, requirements, and schedules of compliance are to be documented in a SIP to be submitted to the EPA.

Once the final ACE is published, states will have 3 years to develop and submit their SIPs to EPA for review. Upon submittal of a SIP, EPA will initially determine if the SIP was satisfactorily "complete", and thereafter would have 12 months to approve or disapprove the SIP. In the event a SIP is not approved, or a state fails to submit a SIP, the EPA will have 2 years to issue a Federal Implementation Plan regulating EGUs in that state.

It remains to be seen whether EPA will finalize its proposed rule to fully repeal, or the proposed ACE rule to revise and replace, the CPP. The outcome of legal challenges, including the suspended CPP litigation, may ultimately influence how GHG emissions from existing EGUs will be regulated. Even in the event the ACE rule is finalized as currently proposed, assuming it will take one year to complete the rulemaking process, by its own terms it will take until approximately 2025 before the initial heat rate improvement projects would be completed. In any event, it will be several years before JEA is required to comply with any regulation targeting greenhouse gas emissions from its existing facilities. While given the current uncertainty as to the wide range of heat improvement projects that could potentially be required, capital costs for these projects generally range in the tens of million dollars.

Proposed ACE Revisions to NSR

To accommodate and facilitate the heat rate improvement projects at the heart of the ACE rulemaking, EPA has also proposed changes to the New Source Review (NSR) permitting program. Currently, modifications to stationary sources that increase annual emissions of regulated (criteria or CO_2) pollutants at or above certain regulatory thresholds are subject to NSR permitting requirements. EPA is now proposing to incorporate a comparison of *hourly* emissions into the NSR applicability assessment for EGUs.[4] Under this approach, once a modification (physical change or change in operations) is determined to occur, the maximum actual emissions values measured on an hourly basis before the project and the projected hourly emission rate that will occur after the proposed modification would be compared to determine if an emissions increase would result. If no emissions increase will occur, NSR would not be applicable, and the associated permitting requirements and burdens would not be triggered. If finalized, this revision could potentially facilitate additional upgrade and plant improvement projects that previously were deferred due to NSR concerns.

1.1.6 Visibility and Regional Haze Rule

On June 2, 1999, the USEPA issued regulations to improve visibility, or visual air quality, in 156 national parks and wilderness areas (i.e., Class I areas) across the country. The rule calls for state and federal agencies to work together to achieve a goal to return Class I areas to pristine conditions by 2064 and requires that states assess "reasonable progress" towards the goal every ten years. The first state plans were due in December 2007 and the next review due in 2018 has been extended to 2021. To the extent that states are not meeting the glide path towards compliance, revised plans to accelerate compliance in order to get back on track with compliance goals are required.

The initial emission reduction initiative to achieve compliance with the Regional Haze Program is known as Best Available Retrofit Technology (BART). BART represents the most effective control for visibility impairing pollutants that is also environmentally friendly, technologically feasible, and cost effective. BART can be applied to 26 different industrial sources, including coal-fired power plants, built between 1962 and 1977. In 2005, the EPA provided an amendment to the Regional Haze Program that provided states with guidelines for developing SIPs to determine which sources of visibility impairing pollutants, including NO_X, SO_2, and particulate matter, will need to install BART.

A BART determination in 2010 determined that no further controls would be needed for Northside Generating Station Unit 3. For Scherer Unit 4, a new scrubber to control SO_2 emissions, and a selective catalytic reduction (SCR) to control NO_X emissions were installed in 2010-2012 in order to address Georgia Regional Haze requirements (in addition to addressing EPA's Clean Air Interstate Rule).

[4] The ACE rule proposes this would apply to *all* EGUs, not just ACE affected EGUs.

Further, given the retirement of St. Johns River Power Park and the potential retirement of Northside Generating Station Unit 3 in 2026[5], it is unlikely that any of these units would be affected by the 2021 reasonable progress update. However, additional compliance requirements could still be in play for Northside Generating Station Units 1 and 2 if it is ultimately determined that emissions from these units are somehow impeding reasonable further progress.

Regarding Scherer Unit 4, upon the implementation of interstate cap-and-trade regulations such as CSAPR, the EPA determined that such regulations control visibility to a greater degree than BART controls. As such, for BART sources operating in states affected by CSAPR, compliance with the cap-and-trade rule supersedes the BART requirement. As long as CSAPR or a similar interstate cap-and-trade rule is in place for Georgia, it is not expected that Scherer Unit 4 would be further affected by Regional Haze/BART.

1.1.7 National Emission Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants (NESHAP) are established under Section 112 of the CAA. The list of regulated hazardous air pollutants (HAPs) was set forth in the Clean Air Act Amendments of 1990. The EPA identified a list of source categories (e.g., electric utility boilers, industrial boilers, combustion turbines, reciprocating internal combustion engines) that included major sources of HAPs (i.e., those sources emitting 10 tpy or more of any one HAP or 25 tpy of any combination of HAPs) and area sources of HAPs (i.e., those sources that are not major sources). Once the various source categories were identified, EPA issued Maximum Achievable Control Technology (MACT) standards for each listed source category according to a prescribed schedule. MACT standards are required to be reevaluated every eight years to determine if additional controls are necessary to reduce health and environmental risks below acceptable levels.

1.1.7.1 40 CFR 63 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units

The most significant MACT standard for coal-fired power plants is known as the Mercury and Air Toxics Standard (MATS). The MATS rule, which was finalized by EPA in December of 2011, established a MACT standard in the form of numerical limits for emissions of mercury, no-mercury metallic HAPs, and acid gas HAPs from coal and oil-fired power plants with a capacity greater than 25 MW. Additionally, MATS established work practice standards for emissions of organic HAPs such as dioxins and furans. Under the MATS rule, affected units can comply with the non-mercury metallic HAPs standards by meeting a surrogate particulate matter emissions limit, a total metals limit, or individual emission limits for ten different metallic HAPs, such as lead, arsenic, and various others. Compliance with acid gas limits can be demonstrated by meeting either a hydrogen chloride limit or a SO_2 limit. Power plants that choose to demonstrate compliance with the acid gas limits by meeting a SO_2 limit must be equipped with add-on FGD systems.

Power plants regulated by MATS were required to demonstrate compliance with the rule by April 16, 2015 unless a one-year extension from the state permitting agency was granted for the

[5] The fundamental assumption of the Integrated Resource Plan (IRP) with which this study is associated was that Northside Unit 3 would retire in the 2025/2026 timeframe. The goal of the IRP was to determine the economics of various replacement options and select a suitable potential replacement.

"installation of controls". An additional year long extension could be granted by the USEPA for sources that could demonstrate that their operation was critical to grid reliability.

Units 1 and 2 at Northside Generating Station and Unit 4 at Scherer are regulated under the MATS rule and are currently in compliance. Unit 3 at Northside Generating Station is currently exempt from emission limits under MATS given that fuel oil combustion is limited by JEA to 10 percent of the of the average annual heat input on a rolling three year average basis and 15 percent of the annual heat input during any one of those calendar years[6]. Although EPA has recently announced its intention to revisit portions of the MATS rulemaking, it is not expected that any new requirements or additional impacts to the JEA fleet will result in the foreseeable future. However, given that NESHAPs such as MATS are required to be reviewed periodically, there is at least some possibility that EPA could increase the stringency of the MATS limits, thus requiring a greater degree of control for compliance.

1.1.7.2 40 CFR 63 Subpart YYYY – National Emissions Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

On March 5, 2004, the EPA published the final NESHAP for stationary combustion turbines. This rule, found at 40 CFR §63 Subpart YYYY, is commonly referred to as the CT MACT. The CT MACT is applicable to stationary gas turbines located at major sources of HAPs. Northside Generating Station is classified as a major source of HAPs.

The CT MACT has been stayed by the EPA for natural gas-fired combustion turbines, however, there are still requirements under the rule for lean premix and diffusion flame oil-fired combustion turbines. According to the Northside Generating Station Draft Title V Renewal (issued August 10, 2018) the four combustion turbines at Northside Generating Station are not subject to regulation under Subpart YYYY. In addition, since Brandy Branch, Kennedy, and Greenland are classified as area (rather than major) sources of HAPs, the combustion turbines at these facilities are not subject to the Subpart YYYY requirements. It is not anticipated that this regulation will have significant impact on the fleet in the future barring the installation of a new combustion turbine at a major HAP facility.

1.1.7.3 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

On June 15, 2004, the EPA established national emission limitations and operating limitations for HAPs emitted from stationary reciprocating internal combustion engines (RICE) located at major and area source of HAP emissions. This rule has since been amended several times, with the most recent amendment on January 30, 2013. The stationary RICE MACT is applicable to the various emergency diesel generators and diesel fire pumps at the JEA facilities. Given that these engines are classified as emergency units under the rule, the requirements for each of these units are generally limited to recording keeping and reporting requirements and maintenance practices.

[6] According to 40 CFR §63.10042, adhering to these limits qualifies the unit as a natural gas-fired unit under the MATS rule. Natural gas-fired units are exempt from emission limits.

1.1.8 New Source Performance Standards

The CAA of 1970 authorized the EPA to establish technology-based emissions standards that apply to specific categories of stationary emissions sources that the EPA has determined "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." These standards, known as New Source Performance Standards (NSPS), apply to new, modified, and reconstructed stationary sources and regulate emissions of several pollutants including, but not limited to, the six criteria pollutants.

The CAA allows the EPA to identify specific facilities within a source category that should be regulated by NSPS and also allows the designation of subcategories. NSPS can be established for specific types of equipment located within a facility or for an entire facility belonging to a regulated source category. Generally, a particular NSPS will regulate facilities or equipment within a facility based on the type of unit, size of unit, material handled, and date of construction, modification, or reconstruction.

NSPS are designed to establish minimum control requirements for all facilities within a source category based on the emissions limitations and reductions that are achieved in practice at the time of the rule-making. The CAA requires the EPA to review each NSPS every eight years in order to determine if the emission limits, controls, and other requirements need to be revised based on technological advancements and/or other changes affecting a particular industry.

1.1.8.1 40 CFR Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators

EPA finalized NSPS Subpart D on December 19, 1995. The rule has been amended several times with the most recent amendment dated June 13, 2007. The rule regulates emissions of particulate matter, SO_2, and NO_X from fossil-fuel-fired steam generating units with a heat input of more than 250 MMBtu/hr that commenced construction or modification after August 17, 1971, except for those sources that are applicable to NSPS Subpart Da or Subpart KKKK. Unit 4 at Scherer is currently applicable to Subpart D, and therefore must adhere to the rule's prescribed NO_X, SO_2, and PM emission limits. . It is worth noting, however, that according to Plant Scherer's most recent Title V permit, Unit 4 is subject to additional, more stringent NO_X, SO_2, and PM emission limits because of applicability to other rules (i.e., MATS, Georgia Rule (jjj)). Compliance with these limits ensures compliance with NSPS Subpart D by default. This rule should have limited future impact on the JEA fleet unless EPA makes significant changes.

1.1.8.2 40 CFR 60 Subpart Da – Standards of Performance for Electric Utility Generating Units

EPA finalized NSPS Subpart Da on June 13, 2007. The rule regulates emissions of PM, SO_2, and NO_X, from electric utility steam generating units that were constructed, modified, or reconstructed after September 18, 1978 and are capable of combusting more than 250 MMBtu/hr of fossil fuel. Units 1 and 2 at Northside Generating Station are currently the only units in JEA's fleet that are regulated under Subpart Da and are operating in compliance with the limits of the rule. This rule should have limited future impact on the boilers unless EPA makes changes to the rule.

1.1.8.3 40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines

EPA finalized NSPS Subpart GG on September 10, 1979. The rule has been amended several times with the most recent amendment dated February 27, 2014. The rule regulates SO_2 and NO_X

emissions from stationary gas turbines with a heat input greater than 10 MMBtu/hr that commenced construction, modification, or reconstruction after October 3, 1977. Gas turbines that are subject to NSPS Subpart KKKK are not subject to Subpart GG. The combustion turbines at Northside generating station were constructed prior to 1977 and, as such, are not applicable to Subpart GG. Subpart GG is, however, applicable to Unit 7 at Kennedy and Unit 1 at Brandy Branch. Given that new and/or modified combustion turbines are now regulated by NSPS Subpart KKKK, this rule should have no significant future impacts on the JEA fleet.

1.1.8.4 40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

The final rule for Subpart KKKK was published in the Federal Register on July 6, 2006 with an amendment to the rule finalized on March 20, 2009. Subpart KKKK is applicable to stationary combustion turbines with a peak load heat input greater than 10 MMBtu/hour that commenced construction, modification, or reconstruction after February 18, 2005. The rule contains emission limits for NO_X and SO_2. NSPS Subpart KKKK is applicable to the combustion turbines at Greenland Energy Center and the combined cycle units at Brandy Branch Generating Station. These units are currently in compliance with the applicable emission limits. Should any new combustion turbines be installed at new or existing facilities or should any changes be made to any of the combustion turbines currently subject to Subpart GG that constitute a modification under the definition in 40 CFR Part 60, then NSPS Subpart KKKK could have future impacts on the JEA fleet. Otherwise, the future impacts of this rule should be minimal unless significant changes are made.

1.1.8.5 40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

On July 11, 2006, the USEPA published Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. Subpart IIII applies to the various emergency diesel-fired RICE generators and fire pumps operating at JEA facilities. This rule should have minimal impact on future operations barring the installation of any non-emergency compression ignition RICE generators.

1.1.8.6 40 CFR 60 Subpart Y – Standards of Performance for Coal Preparation Plants

The final rule for NSPS Subpart Y was published in the Federal Register on October 8, 2009. The rule regulates particulate emissions from coal handling facilities constructed after October 27, 1974 and before April 28, 2008. Subpart Y is applicable to the coal handling system at Scherer and the crusher house and fuel silo dust collectors at Northside Generating Station. This rule is expected to have a minimal impact on future operations.

1.1.8.7 40 CFR 60 Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants

The final rule for NSPS Subpart OOO was published in the Federal Register on April 28, 2009. The rule regulates particulate emissions from mineral processing plants and is currently applicable to the limestone handling systems at Northside Generating Station and Scherer. These systems are currently complying with the requirements of Subpart OOO. This rule is expected to have minimal impacts on future operations.

1.2 WATER AND WASTEWATER REGULATIONS

1.2.1 Clean Water Act 316(b) Cooling Water Intake

EPA published its final Phase II 316b rule regulating cooling water intakes at existing facilities in August 2014. The rule establishes national requirements applicable to the location, design, construction and capacity of cooling water intake structures at existing facilities that reflect the Best Technology Available (BTA) for minimizing adverse impacts of impingement and entrainment. Existing power generation facilities, as well as manufacturing and industrial facilities that withdraw more than 2 million gallons per day from surface waters of the United States and use at least 25 percent of the water exclusively for cooling purposes are subject to the rule.

The final rule established seven alternatives for meeting the impingement requirements – including use of modified traveling screens, reducing through screen design or actual flow velocities, utilizing closed cycle cooling systems, operating existing offshore velocity cap, or meeting a 24% mortality standard on a rolling 12-month basis. Although compliance with entrainment requirements are to be made on a site specific, case-by-case basis, since Northside withdraws over 125 MGD it is required to conduct extensive characterization studies to establish the appropriate BTA. In order to establish the appropriate BTA, affected facilities are required to conduct and submit certain data, studies and plans for compliance (outlined in Table 1-2 below) to the NPDES permitting authority (here the Florida Department of Environmental Protection or FDEP) for review and approval as part of the next NPDES permit renewal application.

JEA's Northside Generating Station is the only facility that is subject to the final Phase II 316b rule, as a result of once-through cooling water being drawn from the St. Johns River in amounts greater than 2 million gallons per day (MGD) with >25% of this withdrawn water used for cooling purposes. Because its actual intake flow is greater than 125 MGD, the facility is subject to the additional entrainment study requirements of this rule.

Table 1-4: Cooling Water Intake Structure Data and Studies

REGULATION	DESCRIPTION
40 CFR 122.21 r(2)	Source Water Physical Data
40 CFR 122.21 r(3)	Cooling Water Intake Structure Data
40 CFR 122.21 r(4)	Source Water Baseline Biological Characterization Data
40 CFR 122.21 r(5)	Cooling Water System Data
40 CFR 122.21 r(6)	Chosen Method(s) of Compliance with Impingement Mortality Standard
40 CFR 122.21 r(7)	Entrainment Performance Studies
40 CFR 122.21 r(8)	Operational Status of each generating unit that uses cooling water
40 CFR 122.21 r(9)	Entrainment Characterization Study
40 CFR 122.21 r(10)	Comprehensive Technical Feasibility and Cost Evaluation Study
40 CFR 122.21 r(11)	Benefits Valuation Study
40 CFR 122.21 r(12)	Non-water Quality Environmental and Other Impacts Study
40 CFR 122.21 r(13)	Peer Review

The previous NPDES permit, which was issued as a combined permit for both the Northside Generating Station and the St. Johns River Power Park, expired on May 8, 2017. JEA submitted an application for renewal of the NPDES in November 2016. In accordance with a previous agreement between the FDEP and the FCG Environmental Committee, a condition will be included in the renewal permit setting forth a timeline for discussion and submittal of the relevant §122.21r data requirements. JEA has several options to consider in selecting a preferred method of compliance, including a combination of upgrading of existing screen systems, shutting down units, and cooling tower installations.

The feasibility of these options will be assessed and costs determined concurrent with completion of the outstanding §122.21r studies. Once the studies and preferred solutions are submitted to the FDEP, the agency will determine the appropriate BTA for the Northside cooling water intake, and will set the schedule for implementing the upgrades and final compliance deadlines.

Since it is likely that JEA will ultimately be required to implement upgrades at the Northside Generating Station, high-level cost estimates for some of the compliance options deemed to be BTA equivalent in the 316b rule that could be considered are set forth in Table 1-5.

Table 1-5 Cooling Water Intake Upgrade Options for 316b Compliance

BTA UPGRADE PROJECT	CONSTRUCTION COSTS (MILLIONS $)	OPERATING COSTS (THOUSAND $/YR)
In-River Intake with Cylindrical Screens	$24 - $51	$7K
In-River Intake with Dual Flow Traveling Screens	$38 - 82	$50K
Distribution Basin Mods with Cylindrical Screens	$21 - $44	$12K
Distribution Basin Mods with Dual Flow Traveling Screens	$31 - $67	$50K
Reduced Flow Alternatives	$14 - $53	$4K - $28K
New closed-cycle cooling towers	TBD	TBD

1.2.2 Effluent Limit Guidelines

The final steam electric effluent limit guidelines (ELG) rule establishing more stringent technology based wastewater discharge standards for steam electric generation plants was published on November 3, 2015. Changes include new standards for wet flue gas desulfurization (WFGD), flue gas mercury control, gasification, and landfill leachate water streams that were previously included under low volume wastes. Additionally, the rules establish a zero discharge standard for fly ash and bottom ash transport waste streams for both new and existing point sources. The final rule did not include any changes to the previously specified cooling tower blowdown, once-through cooling, or coal pile runoff effluent standards.

These ELG standards are to be used by the NPDES permitting authority (FDEP in Florida) in setting applicable discharge limits for specified effluents in new and renewed NPDES and pretreatment permits for steam electric generation facilities. All new ELG limits were not to apply until a date determined by the permitting authority to be "no sooner than" November 1, 2018, but no later than December 31, 2023. Subsequently EPA released a final rule on September 12, 2017 extending the "no sooner than" compliance deadline for bottom ash and WFGD effluents to November 1, 2020.

Currently JEA does not have any effluents that are affected by the ELG rulemaking revisions - as a result of its dry ash handling systems, and absence of WFGD, landfill and gasification at its generation facilities. JEA remains in compliance with the existing ELGs that have already been incorporated into its NPDES permits.

1.3 SOLID WASTE /ASH MANAGEMENT

1.3.1 Coal Combustion Residuals

The Coal Combustion Residuals (CCR) rule published in April 2015 under 40 CFR 257, establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule is intended to address risks from coal ash disposal, such as leaking of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments. Additionally, the rule sets out recordkeeping and reporting requirements as well as the requirement for each facility to establish and post specific information to a publicly accessible website.

The CCR rule contains specific requirements that are to be met in order to continue operation of landfills and surface impoundments (CCR units) at active coal-fired power generation facilities. These requirements include the following:

- Location restrictions.
- Design criteria, including liner design and structural integrity.
- Operating criteria including air criteria, hydrologic and hydraulic capacity requirements, and inspection requirements.
- Groundwater monitoring and corrective action.
- Closure and post-closure care.
- Recordkeeping, notification, and internet posting.

Existing CCR units were to demonstrate compliance with the first four criteria by deadlines staged over 2015-2018 (with one aquifer locational standard deadline recently extended to 2020). Failure to meet or document these items generally results in requirements to cease operation and begin closure or retrofit of the CCR unit. For units that are required to close, the CCR allows two options: (1) leave the CCR in place and install a defined final cover system or (2) remove the CCR and decontaminate the unit.

Although the St. John's River Power Park has ceased operations, its CCR by-products storage area is subject to the EPA rule. JEA has timely demonstrated compliance with the relevant CCR rule requirements to date. The Area A landfill has already been closed, and JEA plans on closing the

Area B Phase 1 in place once receipt of CCR or removal of CCR for beneficial use no longer occurs. JEA has filed and posted a Closure Plan outlining the methods and timing of the Area B Phase 1 area closure.

Because Northside Generation Station fires a combination of fuels, the majority (>50% on a heat input or mass basis) being natural gas and petroleum coke, the CCR rule does not apply to management of these combustion by-products at the facility per 40 CFR 257.50(f).

It is worth noting that a recent August 21, 2018 decision by the federal District of Columbia Circuit Court of Appeals vacated and remanded several provisions of the CCR rule regarding unlined, clay-lined surface impoundments, and those located at inactive (legacy) plants. As of the time of writing, EPA had yet to decide whether to appeal this decision. If it stands, the EPA will need to promulgate revisions to the CCR to address the court findings – at which time it may need to be reviewed to consider how the revisions could impact the SJRPP Byproduct Areas A and/or B.

APPENDIX B. CHARACTERIZATION OF SUPPLY-SIDE OPTIONS

FINAL

CHARACTERIZATION OF SUPPLY SIDE OPTIONS

Natural Gas-Fired Options, Solar & Storage

B&V PROJECT NO. 198807
B&V FILE NO. 40.1100

PREPARED FOR

JEA

9 APRIL 2020

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1.0 Introduction

JEA is developing information that will be used to complete the next iterations of the company's electric system resource planning activities. JEA has tasked Black & Veatch to characterize current, competitive natural gas-fired combustion turbine, internal combustion engine, and solar power plant options. These options will be considered as supply-side options (SSOs) within the upcoming resource planning efforts of JEA.[1]

1.1 OBJECTIVE

The objective of this report is to provide a general overview of the commercially available SSOs, including frame combustion turbine generators (CTGs), aeroderivative CTGs, spark ignition reciprocating internal combustion engines (RICEs), and solar photovoltaic (PV) systems with and without battery storage systems. This overview includes order-of-magnitude estimates of capital costs, operating and maintenance (O&M) costs, thermal performance, and stack emissions for gas-fired power plants employing F-class and advanced class (H-Class) gas turbines, aeroderivative gas turbines, and RICEs operating in both simple cycle and combined cycle configurations. It also includes order-of-magnitude estimates of capital cost, O&M cost, and performance for solar PV and battery storage systems. The information contained in this report will be used by JEA to calculate a Levelized Cost of Energy (LCOE) for each SSO.

1.2 APPROACH

The information and data presented herein are intended to be preliminary, screening-level characteristics suitable for the initial evaluation of multiple SSOs. If an SSO is deemed cost-competitive or selected for further investigation, these estimates may be refined in subsequent stages of planning and development.

The screening-level performance and cost estimates have been developed based on experience with similar generation options, including both recent studies and recent project installations executed by Black & Veatch. Where applicable, Black & Veatch has incorporated recent performance and cost data provided by major Original Equipment Manufacturers (OEMs). This information has been adjusted using engineering judgment to provide values that are considered representative for potential projects that may be implemented by JEA within its service territory.

1.3 REPORT ORGANIZATION

Following this Introduction, this report is organized as follows:

- Section 2.0 – Study Basis and General Assumptions
- Section 3.0 – Gas-Fired Generation Options
- Section 4.0 – Renewable Energy

[1] Note that this document was prepared as of late 2018 to support the Integrated Resource Plan that JEA began in the same timeframe. It has not been brought up to date since then.

2.0 Study Basis and General Assumptions

As part of its current electric system resource planning activities, JEA has identified seventeen gas-fired SSOs to characterize, including seven simple cycle (SC) options and ten combined cycle (CC) options. Simple cycle options would operate as peaking units, while combined cycle options would operate as intermediate/base duty units.

The selected gas turbine SSOs utilize current, commercial large frame CTGs as the prime mover for the facility. As they are representative of current market options, the following turbines supplied by General Electric (GE) have been considered for the characterization of these options:

- GE 7F.05 (in both SC and CC configurations)
- GE 7HA.01 (in both SC and CC configurations)
- GE 7HA.02 (in both SC and CC configurations)
- GE LMS100 (in SC configuration)
- GE LM6000 (in SC configuration)
- Existing GE 7F.03 SC units upgraded to include a 7F.05 compressor and advanced gas path (AGP) upgrade, and converted from SC to CC configuration

The intent of consideration of GE turbines is to provide a consistent comparison within these combustion turbine technology classes. The consideration of GE turbines is not intended to be an implicit recommendation or final technology selection. If an SSO is selected for development, it is recommended that JEA consider all qualified technology suppliers. For example, if JEA investigates advanced class CTG options in subsequent stages of planning and development, it is recommended that JEA consider combustion turbine options offered by GE, Mitsubishi Hitachi Power Systems (MHPS), and Siemens.

The selected RICE SSOs utilize utility-size engines as the prime mover for the facility. Two options were selected to represent the current market options:

- GE Jenbacher J920 Flextra (in SC configuration)
- Wartsila 18V50SG (in SC configuration)

The final SSO is a utility-scale solar array, with a nominal output of 74.9 MW. Consideration will be given to solar arrays both with and without integrated battery storage.

- 75 MW solar array
- 75 MW solar array with 37.5 MW/37.5 MWh Li-ion battery system
- 75 MW solar array with 75 MW/300 MWh Li-ion battery system
- 75 MW solar array with 25 MW/25 MWh Li-ion battery system
- 75 MW solar array with 50 MW/200 MWh Li-ion battery system

2.1 STUDY BASIS FOR GAS-FIRED SUPPLY SIDE OPTIONS

For the purposes of this study, the study basis includes the following:

- Gas-Fired SSOs will be constructed at either the existing Greenland Energy Center (GEC) on the South side of town, or at a brownfield location currently referenced as the North Jax site.
- The GEC site was originally designed for an ultimate buildout of (2) 2x1 F-Class CTG units in CC configuration, plus one SC CTG. There are currently (2) 7FA.03 SC CTGs in SC configuration on the site, along with service water, fire water, control room, fuel oil storage, electrical substation, gas supply line, and other common site equipment already constructed.
- The North Jax site is expected to be parceled out from the now-retired St. Johns River Power Park (SJRPP) site, which is owned by JEA. The potential site is expected to be restored to clean, level ground with no site infrastructure in place except the original SJRPP substation. There is also a low-pressure gas line to the site, formerly used for startup burners.
- Combustion turbines will be dual fuel capable, with natural gas as the primary fuel and Ultra Low Sulfur No. 2 distillate as the secondary fuel.
- Reciprocating internal combustion engines will run on natural gas only.
- For combined cycle options:
  - CTG(s) will be located outdoors in a weather-proof enclosure; the CTGs will be close-coupled to a three-pressure heat recovery steam generator (HRSG). Ancillary CTG skids will also be located outdoors in weather-proof enclosures.
  - The steam turbine will be located outdoors in a weather-proof enclosure.
  - A generation building will house electrical equipment, balance of plant controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms. This facility exists already at GEC, but may need to be expanded.
  - Combined cycle options will utilize wet surface condenser/mechanical draft cooling tower based heat rejection systems. To demonstrate the impacts of utilizing an air-cooled condenser (ACC) based dry heat rejection system, an ACC option will be considered for one 1x1 7HA.02 combined cycle option.
  - Combined cycle options will utilize oxidation catalysts and selective catalytic reduction (SCR) to meet current market Best Available Control Technology (BACT) stack emission rate targets.
  - Combined cycle options will include supplemental HRSG duct firing.
  - Combined cycle options will have conventional start times along with black start capability.
- For simple cycle options:

   - The CTG/RICE will be located outdoors in a weather-proof enclosure. Ancillary CTG/RICE skids will also be located outdoors in weather-proof enclosures.
   - A generation building will house electrical equipment, balance of plant controls, mechanical equipment, warehouse space, offices, break area, and locker rooms. This facility exists already at GEC, but may need to be expanded.
   - Simple cycle CTG options will have fast-start capability where applicable along with black start capability.
   - Simple cycle CTG options will meet New Source Performance Standards (NSPS) through good combustion practices and will not have oxidation catalysts or SCR.
   - Simple cycle RICE options will meet NSPS through good combustion practices and will also have oxidation catalysts and SCR.
- At the GEC facility, it is assumed that supply pressures of natural gas are sufficient to eliminate the need for fuel gas compression for the frame CTGs and RICE, but not the aeroderivative CTGs.[2] At the North Jax site, extensive upgrades to the gas delivery infrastructure would be required for all options but the RICE.[3]

Study basis parameters for the selected gas-fired SSOs are summarized in Table 2-1 and Table 2-2 below.

[2] Because of the structure of the existing supply contract for the GEC site, incremental costs for any increased delivery or pressure from the Peoples Gas System (PGS) owned Seacoast Pipeline to the JEA-owned GEC Lateral serving the Greenland Energy Center have been captured in the IRP as a transportation cost adder to the GEC unit fuel forecast price, rather than as a capital cost added to the unit construction cost or owner's cost.

[3] Pressure and flow to the NGS and SJRPP sites, and to the proposed adjacent or co-located North Jax site via the existing supply system co-owned by JEA and PGS are limited. At the time of this writing, it was expected that JEA would need to execute a JEA-owned pipeline expansion to facilitate the installation of proposed large Frame combustion turbine units, with local compression installed onsite as-needed if Aero units were selected. These costs are reflected as capital cost additions to the first CT installation at the proposed North Jax site, and to any Aero additions as needed. At present time, due to LNG developments proximate to the proposed site, there may be some other cost-effective options available for fuel supply to the site that were not available at the time of this writing.

Table 2-1 Study Basis Parameters for Gas-Fired Peaking SSOs

SSO ID	SUPPLY-SIDE OPTION	PLANT CONFIGURATION	DUTY	AVERAGE AMBIENT NET OUTPUT[1] (MW)	ANNUAL CAPACITY FACTOR (%)	ANNUAL NUMBER OF STARTS
1	2x0 GE LM6000 PF Sprint	Combustion Turbine: GE LM6000 PF Sprint AQC: SCR, CO Catalyst	Peaking	90	10	250
2	1x0 GE LMS100PA+	Combustion Turbine: GE LMS100PA+, with dry interstage cooling AQC: SCR, CO Catalyst	Peaking	112	10	250
3	1x0 GE 7F.05	Combustion Turbine: GE 7F.05 AQC: Good Combustion Practices	Peaking	229	10	250
5	1x0 GE 7HA.01	Combustion Turbine: GE 7HA.01 AQC: Good Combustion Practices	Peaking	284	10	250
8	1x0 GE 7HA.02	Combustion Turbine: GE 7HA.02 AQC: Good Combustion Practices	Peaking	373	10	250
15	5x0 GE Jenbacher J920 Flextra	Reciprocating Engine: GE Jenbacher J920 Flextra AQC: SCR, CO catalyst	Peaking	46	11	250
16	5x0 Wartsila 18V50SG	Reciprocating Engine: Wartsila 18V50SG AQC: SCR, CO catalyst	Peaking	92	11	250

Notes:
1. Average Ambient Net Output values based on ambient conditions of 69°F and relative humidity of 70%, with no inlet chilling.

Table 2-2 Study Basis Parameters for Gas-Fired Intermediate/Base SSOs

SSO ID	SUPPLY-SIDE OPTION	PLANT CONFIGURATION	DUTY	AVERAGE AMBIENT NET OUTPUT[1] (MW)	ANNUAL CAPACITY FACTOR (%)	ANNUAL NUMBER OF STARTS
4	1x1 GE 7F.05	Combustion Turbine: GE 7F.05 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate/ Base	359	35/80	325/5
6	1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate/ Base	426	35/80	325/5
7	2x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate/ Base	856	35/80	325/5
9	1x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate/ Base	559	35/80	325/5
10	2x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate/ Base	1,123	35/80	325/5

SSO ID	SUPPLY-SIDE OPTION	PLANT CONFIGURATION	DUTY	AVERAGE AMBIENT NET OUTPUT[1] (MW)	ANNUAL CAPACITY FACTOR (%)	ANNUAL NUMBER OF STARTS
11	3x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower	Intermediate/ Base	1,689	35/80	325/5
12	1x1 GE 7HA.02	Combustion Turbine: GE 7HA.02 HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Air-Cooled Condenser	Intermediate/ Base	554	35/80	325/5
13	Conversion of existing GEC CTGs to 1x1 GE 7F.03 with .05 compressor/AGP upgrade	Combustion Turbine: GE 7F.03 with .05 compressor/AGP upgrade HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System	Intermediate/ Base	318	35/80	325/5
14	Conversion of existing GEC CTGs to 2x1 GE 7F.03 with .05 compressor/AGP upgrade	Combustion Turbine: GE 7F.03 with .05 compressor/AGP upgrade HRSG: Triple Pressure, Reheat Duct Firing: 15% STG Output AQC: SCR, CO catalyst Steam Turbine: Condensing System	Intermediate/ Base	638	35/80	325/5

Notes:
1. **Average Ambient Net Output values based on ambient conditions of 69°F and relative humidity of 70%, with no inlet chilling.**

2.2 STUDY BASIS FOR SOLAR SUPPLY SIDE OPTIONS

Study basis parameters for the selected solar SSOs are summarized in Table 2-3 below.

Table 2-3 Study Basis Parameters for Solar SSOs

SSO ID	SUPPLY-SIDE OPTION	PLANT CONFIGURATION	BATTERY TYPE	SOLAR PV RATING (MW)	BATTERY RATING (MW)	BATTERY CAPACITY (MWH)
17	Solar Array	no integrated battery storage	N/A	75	N/A	
18	Solar Array with integrated storage	integrated battery storage (37.5 MW capacity, 37.5 MWh Energy), used for load firming/smoothing, using cell type battery technology	Lithium Ion	75	37.5	37.5
19	Solar Array with integrated storage	integrated battery storage (74.9 MW, up to 4 hrs of capacity) for peak shifting to 3-7pm, using cell type battery	Lithium Ion	75	74.9	300
20	Battery Storage addition to existing Solar Array+Transmission.	integrated battery storage (25 MW, 25 MWh) used for load firming/smoothing using cell type battery technology	Lithium Ion	75	25	25
21	Battery Storage addition to existing Solar Array+Transmission.	integrated battery storage (50 MW, up to 4 hrs of capacity) used for peak shifting to 3-7pm using cell type battery technology	Lithium Ion	75	50	200

2.3 DUCT FIRING METHODOLOGY

All duct firing represents a trade-off between increased output and operational flexibility achieved at the expense of worse heat rate, plant footprint, and operational complexity. The level of duct firing can be sized based on material temperature limits, transmission limits, or operational goals. The relevant SSOs are duct fired to an output corresponding to 15% of steam turbine (STG) unfired output to allow for future gas turbine upgrades. CTG manufacturers regularly iterate their technology and offer increased performance on existing units. For example, a 10% increase in output may be realized following upgrades made available at the first major inspection (typically between 50,000 and 65,000 hours of operation). However, these CTG upgrades require large engineering and capital cost efforts to resize the rest of the plant if one sizes the STG and balance-of-plant (BOP) cycle (pumps, pipes, condenser, etc.) only for the original CTG exhaust energy.

Sufficient margin for future CTG upgrades can be incorporated by sizing the level of duct firing output 15% higher than unfired STG output. This intermediate-range planning avoids large rework on the STG and BOP. Even after a CTG upgrade, the duct firing allows flexibility in operation such as on hot days when the CTG output falls due to high ambient temperature.

2.4 BLACK START METHODOLOGY

A black start system allows the starting of a primary generator with no grid connection. Generally, black start systems consist of some number of small diesel or natural gas generators. They are sized for the minimum required starting loads, which can vary based on plant features. Large frame CTGs can draw significant electrical load for their static frequency converter starting mechanisms, in addition to critical loads such as oil pumps and vent fans. Minimal gas compression and BOP equipment needs also need assessed. Finally, proper load sequencing and electrical design can bring up sequentially larger pieces of equipment—for example, starting one of the CTG/HRSG trains in a 3x1, then sequentially bringing the other trains online.

2.5 GENERAL SITE ASSUMPTIONS

In addition to the study basis parameters shown in the tables above, general site assumptions employed by Black & Veatch for these SSOs include the following:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.

- Potable, service, and fire water will be supplied from the local water utility (which is JEA).
- Cooling water, if required, will be supplied from the local water utility (JEA), and is expected to be municipal reclaim water with well water backup.
- Wastewater disposal will utilize local sewer systems.

2.6 CAPITAL COST ESTIMATING BASIS

Screening-level capital cost estimates were developed for each of the SSOs evaluated. The capital cost estimates were developed based on Black & Veatch's experience on projects either serving as engineering, procurement, and construction (EPC) contractor or as owner's engineer (OE). Capital cost estimates are market-based and are based on recent and on-going experiences. The market-based numbers were adjusted based on technology and configuration to arrive at capital cost estimates developed on a consistent basis and reflective of current market trends.

Rather than a "bottoms up" capital cost estimating methodology, the estimates presented herein have been developed using recent historical and current project pricing and then adjusted to account for differences in region, project scope, technology type, and cycle configuration. The basic process flow is as follows:

- **Leverage** confidential and proprietary information, including in-house database of project information from EPC projects recently completed and currently being executed as well as EPC pursuits currently being bid and our knowledge of the market from an owner's engineer perspective to produce a list of potential reference projects based primarily on technology type and cycle configuration.
- **Review** differences in region and scope.
- **Exclude** references which differ significantly from study basis.
- **Adjust** the remaining references by breaking down into several cost categories and accounting for differences such as major equipment pricing, labor, and commodities escalation.
- **Scale** the remaining reference projects by generating a scaling curve and compare**.** That scaling curve forms the basis for the screening-level capital cost estimates and is ultimately used to arrive at the EPC capital cost estimate.

The estimate process described above maximizes the value of past experiences and reduces bias resulting from project outliers such as differences in scope and location with the objective of providing current market pricing for generic power projects in JEA's service territory.

Capital cost estimates presented in Section 3.5 are based on site development as described in section 2.0, under fixed, lump sum EPC contracting. Cost estimates are overnight estimates (i.e., excluding escalation and finance costs) and are presented on a mid-year 2018 US dollars basis. EPC cost estimates are based on Black & Veatch's knowledge of current market trends.

Financing fees and interest during construction will be captured as part of the fixed charge rate that will be applied during the LCOE screening of the SSOs. Land costs, outside-the-fence infrastructure (such as gas delivery upgrades, transmission upgrades, and water and wastewater upgrades), taxes, project management costs, owner's engineering costs, and other "outside-the-fence" costs are considered to be "Owner Costs" and need to be added to the EPC cost estimates to arrive at a total installed cost. A listing of potential owner's costs is presented in Table 2-4. Within this study, owner's cost percentages are estimated for the North Jax site and the GEC site, and applied to capital costs as appropriate. Typically, Owner's costs may be equivalent to 20 to 50 percent of the project's EPC contract cost.

2.7 NON-FUEL OPERATING & MAINTENANCE ESTIMATING BASIS

Black & Veatch developed non-fuel O&M cost estimates for each option under consideration. Non-fuel O&M cost estimates were developed as representative estimates based on previous Black & Veatch experience with projects of similar design and scale, and relevant vendor information available to Black & Veatch. Non-fuel O&M cost estimates were categorized into Fixed O&M and Non-fuel Variable O&M components:

- Fixed O&M costs include labor, routine maintenance and other expenses (i.e., training, office, and administrative expenses).
- Non-fuel Variable O&M costs include outage maintenance (including the costs associated with Long Term Service Agreements [LTSAs] or other maintenance agreements), parts and materials, water usage, chemical usage, and equipment.
- Non-fuel Variable O&M costs exclude the cost of fuel (i.e., natural gas).

Table 2-4 Potential Owner's Costs for Power Generation Projects

Project Development
• Site selection study
• Land purchase/rezoning for greenfield sites
• Transmission/gas pipeline right-of-way
• Road modifications/upgrades
• Demolition
• Environmental permitting/offsets
• Public relations/community development
• Legal assistance
• Provision of project management
 	
Spare Parts and Plant Equipment
• Combustion and steam turbine materials, supplies and parts
• HRS and/or boiler materials, supplies and parts
• SCR and CO catalyst materials, supplies and parts
• Balance-of-plant equipment/tools
• Rolling stock
• Plant furnishings and supplies
• Recip. engine materials, supplies and parts
 	
Plant Startup/Construction Support
• Owner's site mobilization
• O&M staff training
• Initial test fluids and lubricants
• Initial inventory of chemicals and reagents
• Consumables
• Cost of fuel not recovered in power sales
• Auxiliary power purchases
• Acceptance testing
• Construction all-risk insurance
	Owner's Contingency
	• Owner's uncertainty and costs pending final negotiation:
	  • Unidentified project scope increases
	  • Unidentified project requirements
	  • Costs pending final agreements (i.e., interconnection contract costs)
	
	Owner's Project Management
	• Preparation of bid documents and the selection of contractors and suppliers
	• Performance of engineering due diligence
	• Provision of personnel for site construction management
	
	Taxes/Advisory Fees/Legal
	• Taxes
	• Market and environmental consultants
	• Owner's legal expenses
	• Interconnect agreements
	• Contracts (procurement and construction)
	• Property
	
	Utility Interconnections
	• Natural gas service
	• as system upgrades
	• Electrical transmission (including switchyard)
	• Water supply
	• Wastewater/sewer
	
	Financing (may be included in fixed charge rate)
	• Financial advisor, lender's legal, market analyst, and engineer
	• Interest during construction
	• Loan administration and commitment fees
	• Debt service reserve fund

Additional assumptions regarding O&M cost estimates include the following:

- Simple cycle facilities are assumed to operate in peaking service, while combined cycle facilities are assumed to operate in intermediate duty service or base-load service. Assumed annual operating profiles for simple cycle and combined cycle facilities are summarized in Table 2-5.
- Plant staffing assumptions are summarized in Table 2-6 for the various facility configurations under consideration.
- Labor rates for O&M staff were assumed based on information provided by JEA and Black & Veatch experience with similar facilities in the southeastern United States.
- All major maintenance for CTG/RICEs is assumed to be conducted under an LTSA with the OEM. LTSA costs were estimated based on confidential and proprietary recent LTSA proposals (provided to Black & Veatch) for the CTG/RICEs under consideration.
- All plant water consumption (including cooling water) was assumed to be sourced from the local water utility (JEA). Water rates were assumed to be $2.50 per 1000 gallons.
- Cost for additional plant consumables based on information provided by JEA and Black & Veatch experience with similar facilities in the region.
- All non-fuel O&M cost estimates are presented in mid-year 2018 US dollars.

Table 2-5 Annual Operating Profile Assumptions for Facilities

CT FACILITY CONFIGURATION	ANNUAL NUMBER OF STARTS	ANNUAL NUMBER OF HOURS	ANNUAL CAPACITY FACTOR
Simple Cycle CT/RICE Facility	250	876	10%
Combined Cycle CT Facility	325/5	3,066/7,008	35%/80%

Table 2-6 Plant Staffing Assumptions for Facilities

CT FACILITY CONFIGURATION	PLANT STAFFING (FTEs)
1x0 Simple Cycle CT	9
1x1 Combined Cycle CT	17
2x1 Combined Cycle CT	19
3x1 Combined Cycle CT	23
5x0 Simply Cycle RICE	13
Utility Scale Solar	TBD
Combined Cycle Conversion	6 (additional)

3.0 Gas-Fired Generation Options

3.1 GE F-CLASS AND ADVANCED CLASS COMBUSTION TURBINE TECHNOLOGIES

GE F-class combustion turbine technologies provide a demonstrated operating record in the United States and around the world. GE's 7F fleet includes over 900 units, and these units have compiled over 45 million operating hours. The latest iteration of the F-class combustion turbine offered by GE is the 7F.05.

Advanced class machines offer the highest efficiency among frame combustion turbines, with combined cycle efficiencies exceeding 60 percent. For large-scale gas-fired applications (i.e., with simple cycle output greater than 250 MW) at 60 Hz, GE offers two advanced class combustion turbine options, the 7HA.01 and 7HA.02.

3.1.1 Technology Overview: GE 7F.05

The 7F.05 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 3-stage axial turbine, and 14-can-annular dry low NO_x (DLN) combustors. The 7F.05 is GE's fifth-generation 7F machine. Advancements integrated into the 7F.05 design include a redesigned compressor and three variable stator stages and a variable inlet guide vane for improved turndown capabilities. The 7F.05 was introduced in 2009, and the first unit shipped in 2013.

Key attributes of the GE 7F.05 include the following:

- High availability.
- 40 megawatts per minute (MW/min) ramp rate.
- Start to 200 MW in 10 minutes, full load in 11 minutes (excluding purge).
- Natural gas interface pressure requirement of 435 pounds per square inch gauge (psig).
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 9 ppm on natural gas.
- Capable of turndown to 45 percent of full load.
- High exhaust temperature increases the difficulty of implementing post-combustion NOx emissions controls (i.e., SCR).

Cost and performance characteristics have been developed for the following GE 7F.05 combustion turbine configurations:

- 1x0 SC natural gas-fired GE 7F.05 combustion turbine facility.
- 1x1 CC natural gas-fired GE 7F.05 combustion turbine facility.

3.1.2 Technology Overview: GE 7HA.01 and GE 7HA.02

The GE 7HA.01 and GE 7HA.02 are air cooled heavy frame CTGs. Each employs similar design features: a single shaft; 14-stage axial compressor; 4-stage axial turbine; and can-annular DLN combustors. These machines employ a single inlet guide vane stage and three variable stator vane stages to vary compressor geometry for part load operation. The 7HA.01 and the scaled-up 7HA.02 represent the largest and most advanced heavy frame CTG technologies from GE. The compressor design is scaled from GE's 7F.05 and 6F.01 (formally 6C) designs. The 7HA.01 and 7HA.02 employ the DLN 2.6+ AFS (Axial Fuel Staged) fuel staging combustion system, which allows for high firing temperatures and improved gas turbine turndown while maintaining emissions guarantees; providing stable operations; and allowing for increased fuel variability.

The 7HA.01 and the 7HA.02 are among the newest combustion turbine technologies offered by GE. GE has sold 10 7HA.01 machines. In addition to the six at a Japanese site, two units are being installed in the United States, with commercial operations expected to start later this year, and two more units are being manufactured for a project in Mexico, with a planned COD of 2020.

GE has sold 33 7HA.02 gas turbines. The first four 7HA.02 gas turbines entered commercial operations at two separate Exelon sites in Texas in June 2017. In addition, two more 7HA.02 gas turbines are operating commercially in simple cycle in Taiwan, starting September 2017. Eleven more 7HA.02 gas turbines are expected to enter commercial operations in the United States and Korea in 2018. GE expects to have about 500,000 fired hours on the 7HA.02 by 2021.

Key attributes of the GE 7HA.01 and GE 7HA.02 include the following:

- High availability.
- 55 MW/min and 60 MW/min ramp rate for the 7HA.01 and the 7HA.02, respectively.
- Capable of turndown to approximately 25 percent of full load (ambient temperature dependent).
- Natural gas interface pressure requirement of about 540 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 25 ppm on natural gas.

Cost and performance characteristics have been developed for the following advanced class combustion turbine configurations:

- GE 7HA.01
  - 1x0 SC natural gas-fired GE 7HA.01 combustion turbine facility.
  - 1x1 CC natural gas-fired GE 7HA.01 combustion turbine facility.
  - 2x1 CC natural gas-fired GE 7HA.01 combustion turbine facility.
- GE 7HA.02
  - 1x0 SC natural gas-fired GE 7HA.02 combustion turbine facility.
  - 1x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.

- 2x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.
- 3x1 CC natural gas-fired GE 7HA.02 combustion turbine facility.

3.2 GE AERODERIVATIVE COMBUSTION TURBINE TECHNOLOGIES

Aeroderivative CTGs were derived from aerospace jet turbine technology. An aeroderivative CTG is generally a two- or three-shaft turbine with a variable-speed compressor and power turbine. The variable-speed drive is advantageous for part-load efficiency because airflow is reduced with the lower speed.

Turbine inlet temperatures in aeroderivative CTGs are generally higher than in frame CTGs. Aeroderivatives generally offer higher efficiencies than frame CTGs. Furthermore, aeroderivative CTGs are smaller and lighter for a given power output and can be started more rapidly because of the inherently low inertia. The faster start times allow for less fuel consumption during startup. This feature allows the machine to more easily follow load for peaking applications. Aeroderivative CTGs are available in sizes ranging from single digits up to about 100 MW. The machines with the largest market share are in the range of 40 to 60 MW.

Aeroderivative CTGs have higher compressor pressure ratios than frame CTGs resulting in much higher fuel gas pressure requirements. This higher pressure requirement can result in the need for onsite fuel gas compressors.

3.2.1 Technology Overview: GE LMS100

The LMS100 is an intercooled aeroderivative CTG with two compressor sections and three turbine sections. Compressed air exiting the low pressure compressor (LPC) section is cooled in an air-to-water intercooler heat exchanger prior to admission to the high pressure compressor (HPC) section. A mixture of compressed air and fuel is combusted in a single annular combustor (SAC). Hot flue gas then enters the two-stage high pressure turbine (HPT). The high pressure turbine drives the high pressure compressor. Following the high-pressure turbine is a two-stage intermediate pressure turbine (IPT), which drives the low pressure compressor. Lastly, a five-stage low-pressure turbine (LPT) drives the electric generator. Major intercooler components include the inlet and outlet scrolls and associated ductwork to/from the intercooler and the external heat exchanger. Nitrogen oxides (NO_x) emissions are minimized utilizing water injection (for the LMS100PA+) or the use of Dry Low Emission (DLE) combustion technology (for the LMS100PB+).

Many of the major components from the LMS100 are based on engine applications with extensive operating hours. The low-pressure compressor section is derived from the first six stages of GE's MS6001FA heavy-duty CTG compressor. The high-pressure compressor is derived from GE's CF6-80C2 aircraft engine and strengthened to withstand a pressure ratio of approximately 41:1. The single annular combustor and high-pressure turbine are derived from GE's LM6000 aeroderivative turbine and CF6-80C2 and CF6-80E2 aircraft engines.

Key attributes of the GE LMS100PA include the following:

- High full and part load efficiency.

- Minimal performance impact at hot-day conditions.
- High availability.
- 50 MW/min ramp rate.
- 8 minutes to full power (excluding purge).
- Capable of turndown to 25 percent of full load.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 850 psig.
- Dual fuel capable.

The LMS100 is available in several configurations. Major variations include an intercooler heat rejection to atmosphere using dry cooling methods and DLE in lieu of water injected combustion for applications when water availability is limited.

Cost and performance characteristics have been developed for the following GE LMS100 combustion turbine configurations:

- 1x0 SC natural gas-fired GE LMS100 combustion turbine facility.

3.2.2 Technology Overview: GE LM6000

The LM6000 was introduced in 1991, and the LM6000 family of gas turbines has accumulated more than 37 million operating hours with over 1,200 units produced. The baseline LM6000 is a derivative of the CF6-80C2 (Commercial Aircraft) flight gas turbines, and more recently, the CF6-80E1. Models currently commercially offered by GE include the LM6000PC, LM6000PG, LM6000PF, and LM6000PF+.

The LM6000 employs a 5-stage LPC and a 14 stage HPC, an annular combustor, two-stage air-cooled HPT, and a five-stage LPT. All stages of the LPC and six stages of the HPC feature variable-geometry inlet guide vanes. The LPT drives both the LP compressor and the generator load.

The LM6000 SPRINT (SPRay INTercooling) configuration increases power output of the engine by injecting air-atomized demineralized water droplets into the compressor to cool the air flow as the water evaporates on its way through the compressor, increasing power by about 9% at ISO conditions.

The LM6000PC and LM6000PG employ SAC combustion systems. The LM6000PC was introduced in 1997 after approximately 1 million operating hours on models PA / PB. The LM6000PG and PH engines were announced in 2008. Upgrades of LM6000PG, relative to the LM6000PC design, include upgraded materials and increased rotor speed (with addition of a gearbox) to increase power output.

The LM6000PF and LM6000PF+ employ DLE combustion systems. GE introduced the LM6000PF in 2005. The LM6000PF is an upgrade of the LM6000PD. The LM6000PF was the first LM6000 model to employ DLE1.5 technology, which utilized improved combustor design to achieve NOx emissions of 15 ppm. In 2016, GE announced an upgrade of the LM6000PF: the LM6000PF+.

Like the LM6000PG, the LM6000PF+ operates at increased rotor speeds to allow for greater airflow and firing temperature. Additional modifications allow for greater airflow and firing temperature, increasing power output relative to the LM6000PF. In April of 2017, an LM6000PF+ unit was placed into demonstration at a utility host site.

Key attributes of the GE LM6000 include the following:

- High full and part load efficiency.
- High availability.
- 50 MW/min ramp rate.
- 5 minute fast start to full power (excluding purge).
- Capable of turndown to 25 percent of full load (50 percent for DLE).
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 640 psig.
- Dual fuel capable.

Cost and performance characteristics have been developed for the following GE LM6000 combustion turbine configurations:

- 1x0 SC natural gas-fired GE LM6000 combustion turbine facility.

3.3 RECIPROCATING INTERNAL COMBUSTION/TECHNOLOGIES

A reciprocating engine is a heat engine that uses the expansion of hot gases to convert the linear movement of the piston into the rotating movement of a crankshaft to generate power.

Modern reciprocating engines used for electric power generation are internal combustion engines in which an air-fuel mixture is compressed by a piston and ignited within a cylinder. RICE units are characterized by the type of combustion utilized: spark-ignited or compression-ignited, also known as diesel. The spark-ignited engine is based on the Otto thermodynamic cycle and uses a spark plug to ignite an air-fuel mixture injected at the top of the cylinder.

The size and power of a reciprocating engine is a function of the volume of fuel and air combusted. Thus, the size of the cylinder, the number of cylinders, and the engine speed determine the amount of power the engine generates. The output of reciprocating engine generator sets is currently limited to about 20 MW. In a power plant, multiple units are grouped together in a power block to provide generating capacity in standardized sizes. Reciprocating engine power plants are highly efficient with simple cycle efficiencies of 40 to 49 percent (LHV), generally surpassing the performance of SCCT power plants. The biggest concession with reciprocating engines is the operation and maintenance costs often make them less appealing in life-cycle cost analyses.

Many RICE units use a compressed air start system in which compressed air is used to initiate rotation of the crankshaft. RICE units can start quickly and require a minimal amount of electricity and fuel during startup.

3.3.1 Technology Overview: GE Jenbacher J920 Flextra

The GE Jenbacher J920 engine is a two-stage turbocharged 20-cylinder RICE which produces a simple cycle power output range of 9.3-10.4 MW. The engine is cooled by plate heat exchanger made up of a closed loop water circuit resulting in no water loss.

The power unit is made up of a cylinder head, water jacket, liner, piston, and con rod. During the maintenance routine, each cylinder can be separated and replaced in 4 hours. The turbocharger is easily accessible and the intercooler contains small inserts for fast cleaning. The generator, engine, and turbocharger are modularized, providing a high quality and pre-fabricated generator set-module.

The two-stage turbocharger allows for a higher electrical efficiency of 49.9%. The complete J920 engine's turbo charger module is made up of four turbochargers, a two-stage turbocharging system, intercoolers, gas train, oil and water heat exchangers, blow-by system, and an electrical cabinet. This improves lean combustion, increases efficiency, reduces emissions, and reduces fuel costs.

The J920 can run at a stable power output at any ambient condition. Also, individual engines can be run at part load with minor effect on the total plant efficiency. The engine is capable of startup in less than 3 minutes and has extended service intervals for low maintenance cost.

Key attributes of the Jenbacher J920 include the following:

- High full and part load efficiency.
- Minimal performance impact at hot-day conditions.
- 3 minutes to full power (excluding purge).
- Each engine is capable of turndown to 20 percent of full load.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 130 psig.
- Not dual fuel capable.

Cost and performance characteristics have been developed for the following GE Jenbacher J920 RICE configurations:

- 5x0 SC natural gas-fired GE Jenbacher J920 RICE facility.

3.3.2 Technology Overview: Wartsila 18V50SG

The Wartsila 18V50SG reciprocating engine is a turbocharged, four-stroke spark-ignited natural gas engine. Unlike dual fuel reciprocating engines, the SG does not require liquid pilot fuel during startup and to maintain combustion. The 18V50SG utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11/16 inches) and a stroke of 580 millimeters (22-13/16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. These engines employ individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. There have been more than sixty 18V50SG engines sold to date with initial commercial operations starting in 2013.

For this characterization, it is assumed that engine heat is rejected to the atmosphere using an air-cooled heat exchanger, or "radiator." An 18V50SG power plant utilizing air cooled heat exchangers requires very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50SG include the following:

- High full and part load efficiency.
- Minimal performance impact at hot-day conditions.
- 5 minutes to full power (excluding purge).
- Each engine is capable of turndown to 30 percent of full load.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 75 psig.
- Not dual fuel capable.

Cost and performance characteristics have been developed for the following Wartsila 18V50SG RICE configurations:

- 5x0 SC natural gas-fired Wartsila 18V50SG RICE facility.

3.4 WET VS. DRY COOLING CONSIDERATIONS

Combined cycle power plants require large heat rejection systems for proper operation. For a combined cycle power plant with adequate water supply and water discharge capacity, the combination of a surface condenser and wet mechanical draft cooling tower is the most common method of rejecting heat from a steam bottoming cycle to atmosphere. This method of heat rejection allows for a low steam turbine exhaust pressure and temperature, which results in a greater thermal efficiency of the bottoming cycle. However, water losses for this heat rejection method are high compared to alternative, dry cooling methods. For example, operation of a 2x1 7F.05 combined cycle would require approximately 2,000 to 3,000 gallons per minute (gpm) of water during full load operation, depending on ambient conditions.

In areas where water conservation is a high priority or water discharge is not available, air cooled condensers (ACCs) are usually employed. Water losses with an ACC-based heat rejection system are minimal. This method of heat rejection is more expensive in terms of capital cost than a surface condenser and wet mechanical draft cooling tower. Also, the steam turbine exhaust pressure and temperature are typically higher with an ACC, which results in a lower bottoming cycle efficiency compared to wet cooling methods. The reduction in cycle efficiency results in reduced plant output, and increased plant heat rate (less electrical output for the same amount of fuel used).

O&M costs required to maintain an air cooled condenser are higher than the costs required to maintain a surface condenser and wet mechanical draft cooling tower. However, the cost savings in water treatment chemicals would likely offset the additional maintenance cost. Table 3-1 provides a summary comparison for a typical combined cycle operating during hot day conditions. The performance difference during average day conditions would be reduced.

Table 3-1 Typical Combined Cycle Wet versus Dry Cooling Comparison

	WET SURFACE CONDENSER/ WET MECHANICAL DRAFT COOLING TOWER	AIR COOLED CONDENSER
Capital Cost	BASE	+3 to +5 percent
Net Plant Output	BASE	-1.5 to -2.0 percent
Net Plant Heat Rate	BASE	+1.5 to +2.0 percent

Cost and performance characteristics have been developed for the following dry cooling configurations:

- 1x1 CC natural gas-fired GE 7HA.02 combustion turbine facility with ACC.

3.5 SUMMARY OF CAPITAL, OWNERS, AND O&M COST ESTIMATES

Black & Veatch developed order-of-magnitude capital and owners cost estimates for generic gas-fired power plants constructed within the state of Florida, considering SSOs under consideration in this study. Estimates are based on similar studies and project experience and have been adjusted using engineering judgement.

3.5.1 Overnight EPC Capital Cost Estimates

Overnight EPC cost estimates have been prepared considering the estimating basis defined in Section 2. Screening-level estimates of EPC capital costs for both GEC and North Jax are included in Table 3-2 and Table 3-3 below. Owners costs have been included in these tables as well.

Table 3-2 Summary of GEC Gas-Fired Overnight EPC Capital and Owner's Cost Estimates

SSO ID	SUPPLY-SIDE OPTION	EPC COST ($1000) (TYPICAL GREENFIELD)	EPC COST ($M) (SITE-SPECIFIC)	OWNER'S COST ($M)	TOTAL EPC + OWNER'S COST ($M)	OPTIONAL ADDER FOR BLACK START ($M)
1	2x0 GE LM6000 PF Sprint	85,000	82.0	15.3	97.3	0.50
2	1x0 GE LMS100PA+	100,800	97.8	17.8	115.6	1.25
3	1x0 GE 7F.05	89,100	86.1	14.0	100.1	6.25
5	1x0 GE 7HA.01	101,500	98.5	16.0	114.5	6.25
8	1x0 GE 7HA.02	141,200	137.2	22.2	159.4	6.25
15	5x0 GE Jenbacher J920 Flextra	56,400	54.9	9.0	63.9	N/A
16	5x0 Wartsila 18V50SG	94,000	92.5	15.0	107.5	N/A
4	1x1 GE 7F.05	358,800	351.8	56.5	408.3	6.25
6	1x1 GE 7HA.01	411,000	404.0	64.8	468.8	6.25
7	2x1 GE 7HA.01	595,200	586.2	144.0	730.2	6.25
9	1x1 GE 7HA.02	422,500	414.5	66.5	481.0	6.25
10	2x1 GE 7HA.02	620,600	610.6	197.9	808.5	6.25
11	3x1 GE 7HA.02	812,500	800.5	228.3	1,028.8	6.25
12	1x1 GE 7HA.02	443,200	435.2	69.8	505.0	6.25
13	Conversion of existing GEC CTGs to 1x1 GE 7F.03 with .05 compressor/AGP upgrade	247,600	239.6	38.5	278.1	6.25
14	Conversion of existing GEC CTGs to 2x1 GE 7F.03 with .05 compressor/AGP upgrade	446,900	436.9	70.1	507.0	6.25

Table 3-3 Summary of North Jax Gas-Fired Overnight EPC Capital and Owner's Cost Estimates

SSO ID	SUPPLY-SIDE OPTION	EPC COST ($1000) (TYPICAL GREENFIELD)	EPC COST ($M) (SITE-SPECIFIC)	OWNER'S COST ($M)	TOTAL EPC + OWNER'S COST ($M)	OPTIONAL ADDER FOR BLACK START ($M)
1	2x0 GE LM6000 PF Sprint	85,000	85.0	19.0	104.0	0.50
2	1x0 GE LMS100PA+	100,800	100.8	21.5	122.3	1.25
3	1x0 GE 7F.05	89,100	89.1	19.7	108.8	6.25
5	1x0 GE 7HA.01	101,500	101.5	21.6	123.1	6.25
8	1x0 GE 7HA.02	141,200	141.2	28.0	169.2	6.25
15	5x0 GE Jenbacher J920 Flextra	56,400	56.4	14.4	70.8	N/A
16	5x0 Wartsila 18V50SG	94,000	94.0	20.4	114.4	N/A
4	1x1 GE 7F.05	358,800	358.8	62.8	421.6	6.25
6	1x1 GE 7HA.01	411,000	411.0	71.2	482.2	6.25
7	2x1 GE 7HA.01	595,200	595.2	100.6	695.8	6.25
9	1x1 GE 7HA.02	422,500	422.5	203.0	625.5	6.25
10	2x1 GE 7HA.02	620,600	620.6	104.7	725.3	6.25
11	3x1 GE 7HA.02	812,500	812.5	135.4	947.9	6.25
12	1x1 GE 7HA.02	443,200	443.2	76.3	519.5	6.25
13	Conversion of existing GEC CTGs to 1x1 GE 7F.03 with .05 compressor/AGP upgrade	247,600	247.6	45.0	292.6	6.25
14	Conversion of existing GEC CTGs to 2x1 GE 7F.03 with .05 compressor/AGP upgrade	446,900	446.9	76.9	523.8	6.25

The scope of these cost estimates includes all facility generation equipment up to the high-side of the generator step-up transformers. The cost estimates presented include dual fuel systems (to allow operation on either natural gas or distillate oil fuels) for the CTG options.

Within a given estimate, EPC capital costs may be divided into two categories: direct EPC costs and indirect EPC costs. Direct EPC costs include the costs associated with the purchase and installation of major equipment and balance of plant (BOP) equipment. Indirect costs include costs such as engineering, construction management, construction indirects[4], preoperational plant startup and testing, bonding and insurance, and EPC contractor contingency and profit.

3.5.2 Non-Fuel O&M Cost Estimates

Non-Fuel cost estimates have been prepared considering the estimating basis defined in Section 2.7. Estimates of annual non-fuel O&M costs are heavily dependent upon operating profile assumptions such as the number of annual operating hours and the number of annual starts.

For resource planning or general comparison purposes, it is often useful to consider O&M costs on various normalized bases. Fixed O&M costs may be evaluated on a $/kW-yr basis, while variable O&M costs may be evaluated on a $/MWh basis. Given the operating profiles defined for SSOs in Table 2-5, screening-level estimates of non-fuel O&M costs and normalized O&M costs for each SSO are presented in Table 3-4.

[4] Construction indirect costs encompass a variety of items including construction supervision, purchase of small tools and consumables, site services, construction safety program (including development and compliance), installation of temporary facilities and utilities, rental of construction equipment, and heavy haul of construction materials and equipment.

Table 3-4 Summary of Screening-Level Non-Fuel O&M Cost Estimates

SUPPLY SIDE OPTION		2X0 GE LM6000 PF SPRINT	1X0 GE LMS100PA+	1X0 GE 7F.05	1X0 GE 7HA.01	1X0 GE 7HA.02	5X0 GE JENBACHER J920 FLEXTRA	5X0 WARTSILA 18V50SG	1X1 GE 7F.05	1X1 GE 7F.05
SSO ID		1	2	3	5	8	15	16	4	4
Case Number		1	2	3	5	8	15	16	4A	4B
Annual Capacity Factor	%	10%	10%	10%	10%	10%	11%	11%	35%	80%
Starts Per Year	Count	250	250	250	250	250	250	250	325	5
Number of Full Time Equivalent Personnel	Count	9	9	9	9	9	13	13	17	17
Reference Year for Cost Estimates	Year	2018	2018	2018	2018	2018	2018	2018	2018	2018
Net Plant Output (Note 1)	MW	90	112	229	284	373	46	92	359	359
Annual Net Generation	MW-h/yr	79,186	98,339	200,769	248,399	327,061	45,637	91,977	1,101,904	2,518,638
Fixed Costs, Annual	$1000/yr	1,320	1,343	1,787	1,839	1,926	1,876	1,868	3,470	3,470
Variable Costs, Annual	$1000/yr	516	409	2,995	4,603	5,695	438	777	5,323	6,719
Total O&M Costs, Annual	$1000/yr	1,836	1,752	4,782	6,443	7,621	2,314	2,646	8,794	10,189
Fixed Costs, Annual	$/kW-yr	14.6	12.0	7.8	6.5	5.2	41.1	20.3	9.7	9.7
Variable Costs, Annual	$/MW-h	6.52	4.16	14.92	18.53	17.41	9.59	8.45	4.83	2.67

Notes:

1. **Net Plant Output values assume 100 percent load, 69° F ambient, and firing for combined cycle units.**
2. **Different case with the same SSO ID represent different capacity factors.**

SUPPLY SIDE OPTION		1X1 GE 7HA.01	1X1 GE 7HA.01	2X1 GE 7HA.01	2X1 GE 7HA.01	1X1 GE 7HA.02	1X1 GE 7HA.02	2X1 GE 7HA.02	2X1 GE 7HA.02
SSO ID		6	6	7	7	9	9	10	10
Case Number		6A	6B	7A	7B	9A	9B	10A	10B
Annual Capacity Factor	%	35%	80%	35%	80%	35%	80%	35%	80%
Starts Per Year	Count	325	5	325	5	325	5	325	5
Number of Full Time Equivalent Personnel	Count	17	17	19	19	17	17	19	19
Reference Year for Cost Estimates	Year	2018	2018	2018	2018	2018	2018	2018	2018
Net Plant Output (Note 1)	MW	426	426	856	856	559	559	1123	1123
Annual Net Generation	MW-h/yr	1,306,277	2,985,776	2,623,336	5,996,196	1,715,074	3,920,169	3,441,920	7,867,246
Fixed Costs, Annual	$1000/yr	3,577	3,577	4,638	4,638	3,791	3,791	5,066	5,066
Variable Costs, Annual	$1000/yr	7,437	7,729	14,720	15,123	9,119	8,859	18,075	17,337
Total O&M Costs, Annual	$1000/yr	11,015	11,306	19,358	19,761	12,910	12,650	23,140	22,403
Fixed Costs, Annual	$/kW-yr	8.4	8.4	5.4	5.4	6.8	6.8	4.5	4.5
Variable Costs, Annual	$/MW-h	5.69	2.59	5.61	2.52	5.32	2.26	5.25	2.20

Notes:
1. **Net Plant Output values assume 100 percent load, 69° F ambient, and firing for combined cycle units.**
2. **Different cases with the same SSO ID represent different capacity factors.**

SUPPLY SIDE OPTION		3X1 GE 7HA.02	3X1 GE 7HA.02	1X1 GE 7HA.02	1X1 GE 7HA.02	CONVERSION OF EXISTING GEC CTGS TO 1X1 GE 7F.03 WITH .05 COMPRESSOR/AGP UPGRADE	CONVERSION OF EXISTING GEC CTGS TO 1X1 GE 7F.03 WITH .05 COMPRESSOR/AGP UPGRADE	CONVERSION OF EXISTING GEC CTGS TO 2X1 GE 7F.03 WITH .05 COMPRESSOR/AGP UPGRADE	CONVERSION OF EXISTING GEC CTGS TO 2X1 GE 7F.03 WITH .05 COMPRESSOR/AGP UPGRADE
SSO ID		11	11	12	12	13	13	14	14
Case Number		11A	11B	12A	12B	13A	13B	14A	14B
Annual Capacity Factor	%	35%	80%	35%	80%	35%	80%	35%	80%
Starts Per Year	Count	325	5	325	5	325	5	325	5
Number of Full Time Equivalent Personnel	Count	23	23	17	17	17	17	19	19
Reference Year for Cost Estimates	Year	2018	2018	2018	2018	2018	2018	2018	2018
Net Plant Output (Note 1)	MW	1689	1689	554	554	318	318	638	638
Annual Net Generation	MW-h/yr	5,177,369	11,833,987	1,697,568	3,880,156	973,762	2,225,741	1,956,108	4,471,104
Fixed Costs, Annual	$1000/yr	6,643	6,643	3,797	3,797	3,387	3,387	4,093	4,093
Variable Costs, Annual	$1000/yr	27,018	25,815	8,033	6,376	4,681	6,046	9,231	11,811
Total O&M Costs, Annual	$1000/yr	33,661	32,457	11,830	10,173	8,068	9,432	13,323	15,904
Fixed Costs, Annual	$/kW-yr	3.9	3.9	6.9	6.9	10.7	10.7	6.4	6.4
Variable Costs, Annual	$/MW-h	5.22	2.18	4.73	1.64	4.81	2.72	4.72	2.64

Notes:

1. **Net Plant Output values assume 100 percent load, 69° F ambient, and firing for combined cycle units.**
2. **Different cases with the same SSO ID represent different capacity factors.**

4.0 Renewable Energy

For renewable supply side generation, Black & Veatch considered solar and energy storage projects. The following sections discuss the capital and O&M costs as well as the technical unit characteristics for these alternatives.

4.1 SOLAR

The generating characteristics for a solar asset are based on a 75 MWac/105 MWdc project in Jacksonville, FL. B&V assumed an azimuth of 180°, panel tilt of 0°, and single-axis tracking. The DC rating of the

4.1.1 Capital and O&M Costs

The capital costs for the solar project are listed in Table 4-1. The costs assume owner's cost as 20% of EPC cost. Equipment costs include modules, inverters, trackers, and electrical/structural balance of system.

Table 4-1 Solar PV Capital Cost Breakdown

COMPONENT	PRICE ($/WDC)
Equipment	$0.70
Installation	$0.10
Engineering	$0.01
Overhead, Construction Management, Profit	$0.14
Total EPC Cost	**$0.95**
Owner's Cost	$0.20
Total Installed Cost: $/Wdc	**$1.15**

In estimating the O&M cost per kW-year, Black & Veatch assumed that the solar project would be built with equipment from top tier manufacturers and that module washing would not be performed. Black & Veatch considered annual O&M costs, as well as major equipment corrective maintenance. The values in Table 4-2 below are exclusive of asset management and non-technical costs (taxes, lease payments, etc.). Some variables which can impact the O&M price forecasting, but are currently unknown, are agreement scopes, EPC warranty term and terms, major equipment warranties term and terms, plant layout specifics, and number of inverters.

Table 4-2 Solar O&M Cost Estimate ($/kWdc)

DESCRIPTION	PERIOD	COST
Includes 0 module wash/yr; excludes asset management, major equipment corrective maintenance, interconnection costs, non-technical costs (tax/leases) (in real 2018 dollars), includes preventative/ corrective maintenance	Yrs 1-10:	$8 /kWdc/ yr
	Yrs 11-25:	$10 /kWdc/ yr

The expected major maintenance corrective costs are dependent on the scope of major equipment repair and replacement included within the base service fee of the O&M agreement. Assuming that no major equipment repair or replacement is included in the base fee, Table 4-3 below includes a set of reasonable major maintenance assumptions (inverters, modules, transformers, trackers) for a 25-year project life. Black & Veatch notes that these are budgeted spend amounts, and that tracker, module, and transformer replacement do not necessarily need to be modeled as reserves.

Table 4-3 Solar Major Maintenance Corrective Cost Estimate ($/kWdc)

	YEARS 0-5	YEARS 6-10	YEARS 11-25
Nominal Major Equipment Overhaul/Replacement Cost	$0/kWdc	$2/kWdc	$4/kWdc

4.1.2 Technical Characteristics

The technical unit characteristics include the annual solar resource, generation, and capacity factor. The estimated annual solar resource is 1,674 kWh/m^2/year and is based on Global Horizontal Irradiance; derived from NSRDB (Jacksonville Airport TMY2). The first year estimated generation is 184,500 MWh (ac), and the net capacity factor (ac) is 28 percent. Both values are based on an energy simulation result.

4.2 ENERGY STORAGE

Although it is not a generation resource, energy storage can perform many of the same applications like a traditional generator by using stored energy from the grid or from other distributed generation resources. These applications range from traditional uses such as providing capacity or ancillary services to more unique applications such as microgrids or renewable energy integration applications. Utility scale energy storage applications with their brief descriptions are provided below:

- Electric Energy Time-Shift (Arbitrage): The use of energy storage to purchase energy when prices are low and shift that energy to be sold when prices are higher (during peak times).
- Electric Supply Capacity: The use of energy storage to provide system capacity during peak hours.

- Frequency Regulation: The use of energy storage to mitigate load and generation imbalances on the second to minute interval to maintain grid frequency.
- Spinning Reserve: The use of energy storage that is online and synchronized to supply generation capacity within 10 minutes.
- Non-Spinning Reserve: The use of energy storage that is offline but can be ramped up and synchronized to supply generation capacity within 10 minutes.
- Voltage Support: The energy storage converter can provide reactive power for voltage support and respond to voltage control signals from the grid.
- Variable Energy Resource Capacity Firming: The use of energy storage to firm energy generation of a variable energy resource so that output reaches a specified level at certain times of the day.
- Variable Energy Resource Ramp Rate Control: Ramp rate control can be used to limit the ramp rate of a variable energy resource to limit the impact to the grid.
- Transmission and Distribution Upgrade Deferral: The use of energy storage to avoid or defer costly transmission and distribution upgrades.

Some of the applications listed above such as Ramp Rate Control or Capacity Firming are location specific and require nearby renewable energy sources such as utility scale solar or wind generation, whereas applications such as Electric Energy Time-Shift or Frequency Regulation can be location independent and be performed at different locations on the grid.

It should be noted that the applications are often grouped into either power or energy applications. Power applications are generally shorter duration (approximately 30 minutes to one hour) applications that may involve frequent rapid responses or cycles. Frequency regulation or other renewable integration applications such as ramp rate control/ smoothing are good examples of power applications. Energy applications generally require longer duration (approximately 2 hours or more) energy storage systems. Electric Supply Capacity, Electric Energy Time-Shift, and Transmission and Distribution Upgrade Deferral are examples of energy applications.

4.2.1 JEA Evaluation for Battery Energy Storage

When evaluating system size and location for battery storage, the intended application(s) are paramount for the decision process. Black & Veatch has provided technology summaries for two different applications at greenfield and existing sites. The options are summarized in Table 4-4 below.

Table 4-4 Battery Technology Option Overview

LOCATION	APPLICATION	RATING (MW)	SIZE (MWH)	BATTERY TECHNOLOGY
Greenfield 74.9 MW Solar Facility	Load firming/smooth	37.5	37.5	Cell Battery
Greenfield 74.9 MW Solar Facility	Peak Shifting	74.9	300	Cell Battery
Existing Site, expected 2019 COD	Load firming/smooth	25	25	Cell Battery
Existing Site, expected 2019 COD	Peak Shifting	50	200	Cell Battery

4.2.2 Battery Technology Overview

Batteries are electrochemical cells that convert chemical energy into electrical energy. This conversion is achieved via electrochemical oxidation-reduction (redox) reactions occurring at the electrodes of the batteries. The main components of a battery are the positive electrode (cathode), the negative electrode (anode) and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.[5] Batteries store direct current (DC) charge, so power conversion is necessary to interface a battery with an alternative current (AC) power system.

Battery energy storage systems (BESS) employ multiple (up to several thousand) batteries that are connected in series and/or parallel, and are charged via an external source of electrical energy. The BESS discharges this stored energy to provide a specific electrical function.

A fully operational BESS comprises of an energy storage system that is combined with a bidirectional converter (also called a power conversion system). The BESS also contains a Battery Management System (BMS) and a Site or BESS Controller and is summarized in Table 4-5.

Table 4-5 BESS Components

COMPONENT	DEFINITION
Energy Storage System (ESS)	The ESS consists of the battery modules or components as well as the racking, mechanical components and electrical connections between the various components.
Power Conversion System (PCS)	The PCS is a bi-directional converter that converts AC to DC and DC to AC. The PCS also communicates with the BMS and BESS controller.
Battery Management System (BMS)	The BMS can be comprised of various BMS units at the cell, module and system level. The BMS monitors and manages the battery state of charge (SOC) and charge and discharge of the ESS.
BESS/ Site Controller	The BESS controller communicates with all the components and is also the utility communication interface. Most of the advanced algorithms and control of the BESS resides in the BESS/ Site Controller.

[5] T. B. Reddy, “Linden’s Handbook of Batteries,” 4th Edition, November 2010.

When considering different energy storage technologies, there are several key performance parameters to understand:

- **Power Rating**: The rated power output (MW) of the entire ESS.
- **Energy Rating**: The energy storage capacity (MWh) of the entire ESS.
- **Discharge Duration**: The typical duration that the BESS can discharge at its power rating
- **Response Time**: How quickly an ESS can reach its power rating (typically in milliseconds).
- **Ramp-rate**: how quickly an energy storage system can change its power output, typically in MW/min
- **Charge/Discharge Rate (C-Rate)**: A measure of the rate at which the ESS can charge/discharge relative to the rate at which will completely charge/discharge the battery in one hour. A one hour charge/ discharge rate is a 1C rate, while a 2C rate completely charges/discharges the ESS in 30 minutes.
- **Round Trip Efficiency**: The amount of energy that can be discharged from an ESS relative to the amount of energy that went into the battery during charging (as a percentage). Typically stated at the point of interconnection and includes the ESS, PCS and transformer efficiencies.
- **Depth of Discharge (DOD)**: The amount of energy discharged as a percentage of ESS overall energy rating.
- **State of Charge (SOC)**: The amount of energy an ESS has charged relative to its energy rating, noted as a percentage.
- **Cycle Life**: Number of cycles before ESS reaches 80 percent of initial energy rating. The cycle life typically varies for various DODs.

Battery types employed within energy storage systems typically include lithium ion (Li-ion), flow, lead-acid, or sodium sulfur (NaS) batteries. Most of the stationary energy storage activity in the industry is currently based on the lithium ion battery technology. Lithium ion batteries are the dominant player in battery energy storage, and their demonstrated experience is growing. Lithium ion batteries are projected to be a major industry player in the years to come and are well suited for both power and cycling applications as well as some energy applications.

Redox flow battery installations are more limited; however, redox flow batteries are also projected to likely have a considerable market share for large stationary applications in the future and are best suited for energy applications that require longer durations of discharge.

4.2.2.1 Lithium Ion Batteries

Lithium ion batteries are a form of energy storage where all the energy is stored electrochemically within each cell. During charging or discharging, lithium ions are created and are the mechanism for charge transfer through the electrolyte of the battery. In general, these systems vary from vendor to vendor by the composition of the cathode or the anode.

The battery cells are integrated to form modules. These modules are then strung together in series and/or parallel to achieve the appropriate power and energy rating to be coupled to the PCS.

Lithium ion battery energy storage systems are typically used for both power and energy applications. The primary strength of lithium ion batteries is the strong cycle life. For shallow, frequent cycles, which are quite common for power applications, lithium ion systems demonstrate good cycle life characteristics. Additionally, lithium ion systems demonstrate good cycle life characteristics for deeper discharges common for energy applications. Overall, this technology offers the following benefits:

- **Excellent Cycle Life**: Lithium ion technologies have superior cycling ability to other battery technologies such as lead acid.
- **Fast Response Time**: Lithium ion technologies have a fast response time which is typically less than 100 milliseconds.
- **High Round Trip Efficiency**: Lithium ion energy conversion is efficient and has around 94 percent round trip efficiency (DC-DC).
- **Versatility**: Lithium ion solutions can provide many relevant operating functions.
- **Commercial Availability**: There are many top tier lithium ion vendors.
- **Energy Density**: Lithium ion solutions have a high energy density to meet space constraints.

Various Li-ion battery systems are installed around the world, including projects in the United States. The 32 MW Laurel Mountain Project in West Virginia, the 32 MWh Tehachapi Project in California, and other projects in Chile and China employ Li-ion systems. According to the DOE Energy Storage Database, the United States installed (including under construction) capacity of Li-ion is about 792 MW and the worldwide installed (including under construction) capacity of Li-ion is about 2,007 MW.[6]

O&M activities for Li-Ion energy storage systems typically involve annual scheduled maintenance. During this maintenance, visual inspection of the system components and status check is performed as well as expendable parts such as filters are replaced. Software updates regarding BMS can be applied during this maintenance period.

Different lithium ion vendors employ different lithium ion chemistry for their product. Each chemistry composition is slightly different in terms of its performance characteristics, namely, cycle life, charge rate capabilities, and energy density. They also vary in terms of the typical applications (which are primarily dictated by the performance parameters) they perform and their relative safety characteristics.

The main types of lithium ion chemistries are shown in Table 4-6 as well as the associated strengths and weaknesses of the chemistries. It should be noted that the chemistries listed are relevant chemistries for grid scale energy storage. The source of the information is from Battery University, Linden's Handbook of Batteries and Black & Veatch's Engineering, Procurement and Construction (EPC) experience.

[6] Sandia National Laboratories, "DOE Global Energy Storage Database," http://www.energystorageexchange.org/, October 2018.

Table 4-6 Lithium Ion Chemistries for Energy Storage

CHEMISTRY	CYCLE LIFE[1]	CHARGE RATE	SPECIFIC ENERGY[7]	APPLICATIONS	SAFETY
Lithium Manganese Oxide (LMO)	4000 – 5000 cycles	0.25C to 3C	100-150 Wh/kg	Both power and energy applications	Good
Lithium Nickel Manganese Cobalt Oxide (NMC)	4000 – 5000 cycles	0.25C to 3C	150-220 Wh/kg	Often have separate power and energy cells	Good
Lithium Iron Phosphate (LFP)	3000 – 5000 cycles	0.25C to 2C. 4C with power cells.	90-120 Wh/kg	Often have separate power and energy cells	Very good
Lithium Nickel Cobalt Aluminum Oxide (NCA)	3000 (better at shallow DODs)	0.5C to 3C	200-260 Wh/kg	Often have separate power and energy cells	Good
Lithium Titanate (LTO)	5000 – 10000 cycles	1C to 6C	50-80 Wh/kg	Power applications	Good

Notes:

1. **Cycle life is based on cycles to reach 80% initial energy storage capacity at 1 C rate. DoD for each cycle is assumed to be around a full DOD, or 90%.**

Black & Veatch maintains a database of over 80 energy storage providers in the industry. Of these, there are a significant number of lithium ion suppliers. Black & Veatch's recent EPC experience has allowed us to narrow the long list of suppliers to the top tier candidates. The top tier lithium ion battery suppliers Black & Veatch frequently engages are listed in Table 4-7.

Table 4-7 Lithium Ion Battery Storage Providers

CHEMISTRY	MANUFACTURER
Lithium Manganese Oxide (LMO)	Samsung SDI
Lithium Nickel Manganese Cobalt Oxide (NMC)	LG Chem
Lithium Iron Phosphate (LFP)	BYD, NEC Energy Solutions
Lithium Nickel Cobalt Aluminum Oxide (NCA)	Saft, Tesla
Lithium Titanate (LTO)	Toshiba

[7] Battery University, "BU-205: Types of Lithium-ion," http://batteryuniversity.com/learn/article/types_of_lithium_ion, October 2018.

4.2.3 Cost Parameters

The following tables gives the cost parameters for the different battery storage options.

Table 4-8 Representative Costs for Energy Storage Systems

PARAMETER				
Facility Power Rating, MW	37.5	25	50	75
Facility Energy Rating, MWh	37.5	25	200	300
ESS Cost[1] $	11.51	8.03	60.20	84.90
PCS Cost $	2.44	1.63	3.25	4.88
Balance of System Direct Cost[2] $	1.97	1.42	3.53	5.17
Balance of System Indirect Cost[3] $	1.11	0.92	1.69	2.23
Installed EPC Costs[4] $	17.02	11.99	68.67	97.18
EPC Cost per kW $	372.0	386.0	1,269.0	1,197.0
EPC Cost per kWh $	372.0	386.0	317.3	299.3
Fixed O&M Costs $/kW-yr[5]	2.44	2.44	8.20	8.20

Notes:
1. Inclusive of containerization
2. Direct costs are inclusive of balance of system electrical, civil, interconnection, SCADA, equipment, and labor
3. Indirect costs are inclusive of engineering and project management, builder's insurance bonding and warranty. Sales tax, EPC markup, and development costs are not considered.
4. Installed costs are based on 2019 COD
5. Battery replacement and capacity maintenance not included in Fixed O&M Cost

Appendix A. Cost and Performance Tables

The following tabular summaries provide supporting information for this IRP

O&M Cost Summary

Natural Gas Options - Capital and Owner's Costs

Thermal Performance Summary - Natural Gas

Battery Storage Capital Costs

JEA Battery Storage O&M

JEA														
	Option Number	1	2	3	4	4	5	6	6	7	7	8	9	9
	Case Number	1A	2A	3A	4A	4B	5	6A	6B	7A	7B	8	9A	9B
B&V Project Number 198807														
Preliminary Non-fuel O&M Cost Estimates, Rev 3														
Option Arrangement														
Original Equipment Manufacturer		GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE	GE
Technology		LM6000 PF Sprint	LMS100 PA+	7F.05	7F.05	7F.05	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.02	7HA.02	7HA.02
Cycle Configuration		Simple	Simple	Simple	Combined	Combined	Simple	Combined	Combined	Combined	Combined	Simple	Combined	Combined
Equipment Configuration		2x0	1x0	1x0	1x1	1x1	1x0	1x1	1x1	2x1	2x1	1x0	1x1	1x1
Steam Turbine Heat Rejection		NA	NA	NA	WMDCT	WMDCT	NA	WMDCT	WMDCT	WMDCT	WMDCT	NA	WMDCT	WMDCT
Duct Firing Capacity, Gross, MW		n/a	n/a	n/a	17.8	17.8	n/a	19.7	19.7	39.8	39.8	n/a	25.8	25.8
General Plant Information														
Net Plant Output (Note 1)	MW	90.4	112.3	229.2	359.4	359.4	283.6	426.1	426.1	855.6	855.6	373.4	559.4	559.4
Annual Capacity Factor	%	10.0%	10.0%	10.0%	35.0%	80.0%	10.0%	35.0%	80.0%	35.0%	80.0%	10.0%	35.0%	80.0%
Starts Per Year	Count	250	250	250	325	5	250	325	5	325	5	250	325	5
Number of Full Time Equivalent Personnel	Count	9	9	9	17	17	9	17	17	19	19	9	17	17
Reference Year for Cost Estimates	Year	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018
O&M Cost Summary														
Net Plant Output (Note 1)	MW	90.4	112.3	229.2	359.4	359.4	283.6	426.1	426.1	855.6	855.6	373.4	559.4	559.4
Annual Net Generation	MW-h/yr	79,186	98,339	200,769	1,101,904	2,518,638	248,399	1,306,277	2,985,776	2,623,336	5,996,196	327,061	1,715,074	3,920,169
Fixed Costs, Annual	$1000/yr	1,320	1,343	1,787	3,470	3,470	1,839	3,577	3,577	4,638	4,638	1,926	3,791	3,791
Variable Costs, Annual	$1000/yr	516	409	2,995	5,323	6,719	4,603	7,437	7,729	14,720	15,123	5,695	9,119	8,859
Total O&M Costs, Annual	$1000/yr	1,836	1,752	4,782	8,794	10,189	6,443	11,015	11,306	19,358	19,761	7,621	12,910	12,650
Fixed Costs, Annual	$/kW-yr	14.6	12.0	7.80	9.66	9.66	6.49	8.40	8.40	5.42	5.42	5.16	6.78	6.78
Variable Costs, Annual	$/MW-h	6.52	4.16	14.92	4.83	2.67	18.53	5.69	2.59	5.61	2.52	17.41	5.32	2.26

Notes:

1. Net Plant Output values assume 100 percent load, 69° F ambient, and firing for combined cycle units.

		14	15	16	17	18	19	20	21	22	23	24	25
JEA	Option Number	10	10	11	11	12	12	13	13	14	14	15	16
	Case Number	10A	10B	11A	11B	12A	12B	13A	13B	14A	14B	15	15
B&V Project Number 198807													
Preliminary Non-fuel O&M Cost Estimates, Rev 3													
Option Arrangement													
Original Equipment Manufacturer		GE	GE	GE	GE	GE	GE	GE/TBD	GE/TBD	GE/TBD	GE/TBD	Jenbacher	Wartsila 18V50SG
Technology		7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	920	18V50SG
Cycle Configuration		Combined	Combined	Combined	Combined	Combined	Combined	Combined	Combined	Combined	Combined	Simple	Simple
Equipment Configuration		2x1	2x1	3x1	3x1	1x1	1x1	1x1	1x1	2x1	2x1	5x0	5x0
Steam Turbine Heat Rejection		WMDCT	WMDCT	WMDCT	WMDCT	ACC	ACC	WMDCT	WMDCT	WMDCT	WMDCT	n/a	n/a
Duct Firing Capacity, Gross, MW		52.1	52.1	78.8	78.8	24.9	24.9	7.1	7.1	14.1	14.1	n/a	n/a
General Plant Information													
Net Plant Output (Note 1)	MW	1,122.6	1,122.6	1,688.6	1,688.6	553.7	553.7	317.6	317.6	638.0	638.0	45.7	92.1
Annual Capacity Factor	%	35.0%	80.0%	35.0%	80.0%	35.0%	80.0%	35.0%	80.0%	35.0%	80.0%	11.4%	11.4%
Starts Per Year	Count	325	5	325	5	325	5	325	5	325	5	250	250
Number of Full Time Equivalent Personnel	Count	19	19	23	23	17	17	17	17	19	19	13	13
Reference Year for Cost Estimates	Year	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018	2018
O&M Cost Summary													
Net Plant Output (Note 1)	MW	1,122.6	1,122.6	1,688.6	1,688.6	553.7	553.7	317.6	317.6	638.0	638.0	45.7	92.1
Annual Net Generation	MW-h/yr	3,441,920	7,867,246	5,177,369	11,833,987	1,697,568	3,880,156	973,762	2,225,741	1,956,108	4,471,104	45,637	91,977
Fixed Costs, Annual	$1000/yr	5,066	5,066	6,643	6,643	3,797	3,797	3,387	3,387	4,093	4,093	1,876	1,868
Variable Costs, Annual	$1000/yr	18,075	17,337	27,018	25,815	8,033	6,376	4,681	6,046	9,231	11,811	438	777
Total O&M Costs, Annual	$1000/yr	23,140	22,403	33,661	32,457	11,830	10,173	8,068	9,432	13,323	15,904	2,314	2,646
Fixed Costs, Annual	$/kW-yr	4.51	4.51	3.93	3.93	6.86	6.86	10.66	10.66	6.42	6.42	41.06	20.29
Variable Costs, Annual	$/MW-h	5.25	2.20	5.22	2.18	4.73	1.64	4.81	2.72	4.72	2.64	9.59	8.45

Notes:

1. Net Plant Output values assume 100 percent load, 69° F ambient, and firing for combined cycle units.

GEC Site

Technology		LM6000 PF	LMS100PA+	7F.05	7F.05	7HA.01	7HA.01	7HA.01	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7F.03 w/Upgrade	7F.03 w/Upgrade	Jenbacher 920 Flextra	18V50SG
Configuration		2x0 SC	1x0 SC	1x0 SC	1x1 CC	1x0 SC	1x1 CC	2x1 CC	1x0 SC	1x1 CC	2x1 CC	3x1 CC	1x1 CC (ACC)	Conversion to 1x1 CC	Conversion to 2x1 CC	5x0 RICE	5x0 RICE
Nominal New Generation (MW)		90.4	112.3	229.2	359.4	283.6	426.1	855.6	373.4	559.4	1122.6	1688.6	553.7	165.4	330.7	45.7	92.1
EPC Cost Adjustments	**% or $M**																
Generation+Admin Building	(4.0)	(1.0)	(1.0)	(1.0)	(2.0)	(1.0)	(2.0)	(3.0)	(1.0)	(3.0)	(4.0)	(5.0)	(3.0)	(3.0)	(4.0)	(1.0)	(1.0)
Water	(3.0)	(1.0)	(1.0)	(1.0)	(3.0)	(1.0)	(3.0)	(3.0)	(1.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(0.5)	(0.5)
Groundwork	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Oil Storage and Forwarding	(3.0)	(1.0)	(1.0)	(1.0)	(2.0)	(1.0)	(2.0)	(3.0)	(2.0)	(2.0)	(3.0)	(4.0)	(2.0)	(2.0)	(3.0)	0.0	0.0
Owner's Absolute Cost Allowances	**% or $M**																
Gas Supply	0.0	2.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electrical Interconnect	100.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	100.0	100.0	0.0	0.0	0.0	0.0	0.0
Permitting	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Owner's Relative Cost Allowances	**% or $M**																
Owner's Contingency	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Spare Parts	1.50%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Owner's Project Management	2%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Owner's Startup/Construction Support	1.50%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Taxes/Advisory Fees/Legal	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Project Development (selection, land purchase,	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Interest during construction	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Financing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EPC Cost Adjustments ($M)	$M	(3.0)	(3.0)	(3.0)	(7.0)	(3.0)	(7.0)	(9.0)	(4.0)	(8.0)	(10.0)	(12.0)	(8.0)	(8.0)	(10.0)	(1.5)	(1.5)
Owner's Absolute Cost Allowances ($M)	$M	2.2	2.2	0.2	0.2	0.2	0.2	50.2	0.2	0.2	100.2	100.2	0.2	0.2	0.2	0.2	0.2
Owner's Relative Costs Allowances	$M	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
EPC Cost ($1000) (Typical Greenfield)	$1,000	85,000	100,800	89,100	358,800	101,500	411,000	595,200	141,200	422,500	620,600	812,500	443,200	247,600	446,900	56,400	94,000
EPC Cost ($M) (Site-Specific)	$M	82.0	97.8	86.1	351.8	98.5	404.0	586.2	137.2	414.5	610.6	800.5	435.2	239.6	436.9	54.9	92.5
Total EPC + Owner's Cost ($M)	$M	97.3	115.6	100.1	408.3	114.5	468.8	730.2	159.4	481.0	808.5	1028.8	505.0	278.1	507.0	63.9	107.5
Optional Adder for Black Start ($M)	$M	0.5	1.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	N/A	N/A

GEC Description	The GEC site was originally designed for an ultimate buildout of (2) 2x1 F-Class CTG units in CC configuration, plus one SC CTG. There are currently (2) 7FA.03 SC CTGs in SC configuration on the site, along with service water, fire water, control room, fuel oil storage, electrical substation, gas supply line and other common site equipment already constructed.

EPC Cost Adjustments	Site Notes	Option-Specific Notes
Generation+Admin Building	Generation building already exists, saving 4 M on EPC price of a 2x1 Combined	Saved generation building costs: $1M for simple cycle, $3M for 1x1, +1$M for every
Water	Potable, service water, fire water, and sanitary sewer infrastructure is in place. Cooling tower makeup and blowdown disposal interconnections are not in place, but will be provided by JEA water group.	
Groundwork	Site is fully cleared, graded and fenced.	
Fuel Oil Storage and Forwarding	Already established	Saved fuel oil storage and forward costs scaled with output for CTG options

Owner's Absolute Cost Allowances	Site Notes	Option-Specific Notes
Gas Supply	Contractual negiotations and gas compression in play.	Contractual negotiations will cover gas supply needs for non-aeroderivatives. $2 million
Electrical Interconnect	Bus structure exists for next (2) interconnections. Bays will need to be equipped, and transmission upgrades costing approximately $100M will be required to interconnect a 500MW 1x1 Advanced class CC. Interconnection of an additional CC would require additional transmission upgrades, and is not the preferred site for additional generation at this time.	1. Capacity additions at GEC up to 600 MW will need $0 in transmission upgrades. 2. Capacity additions at GEC greater than 600 MW and up to 900 MW will need at least $50 million in transmission upgrades. 3. Capacity additions at GEC greater than 900 MW will need at least $100 million in transmission upgrades; this value is a rough estimate, as it would require a multiple week/month long study to assess.
Permitting	Some small permitting done	

Owner's Relative Cost Allowances	Site Notes	Option-Specific Notes
Owner's Contingency	Recommendation requested	
Spare Parts	Required	
Owner's Project Management	Required	
Owner's Startup/Construction Support	Required	
Taxes/Advisory Fees/Legal	Assume covered property and tax law and interconnection agreements	
Project Development (selection, land purchase,	Assume covered site selection study, land cost, road mods, demolition, and	
Interest during construction	To be included in LCOE calculation	
Financing	To be included in LCOE calculation	

North Jax

Technology Configuration Nominal New Generation (MW)		LM6000 PF 2x0 SC 90.4	LMS100PA+ 1x0 SC 112.3	7F.05 1x0 SC 229.2	7F.05 1x1 CC 359.4	7HA.01 1x0 SC 283.6	7HA.01 1x1 CC 426.1	7HA.01 2x1 CC 855.6	7HA.02 1x0 SC 373.4	7HA.02 1x1 CC 559.4	7HA.02 2x1 CC 1122.6	7HA.02 3x1 CC 1688.6	7HA.02 1x1 CC (ACC) 553.7	7F.03 w/Upgrade Conversion to 1x1 CC 165.4	7F.03 w/Upgrade Conversion to 2x1 CC 330.7	Jenbacher 920 Flextra 5x0 RICE 45.7	18V50SG 5x0 RICE 92.1
EPC Cost Adjustments	**% or $M**																
Generation+Admin Building	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Groundwork	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Oil Storage and Forwarding	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Owner's Absolute Cost Allowances	**% or $M**																
Gas Supply	130.0									130.0						0.0	0.0
Electrical Interconnect	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Permitting	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Owner's Relative Cost Allowances	**% or $M**																
Owner's Contingency	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Spare Parts	1.50%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Owner's Project Management	2%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Owner's Startup/Construction Support	1.50%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%
Taxes/Advisory Fees/Legal	0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Project Development (selection, land purchase,	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Interest during construction	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Financing	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
EPC Cost Adjustments ($M)	$M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Owner's Absolute Cost Allowances ($M)	$M	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	135.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Owner's Relative Costs Allowances	$M	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
EPC Cost ($1000) (Typical Greenfield)	$1,000	85,000	100,800	89,100	358,800	101,500	411,000	595,200	141,200	422,500	620,600	812,500	443,200	247,600	446,900	56,400	94,000
EPC Cost ($M) (Site-Specific)	$M	85.0	100.8	89.1	358.8	101.5	411.0	595.2	141.2	422.5	620.6	812.5	443.2	247.6	446.9	56.4	94.0
Total EPC + Owner's Cost ($M)	$M	104.0	122.3	108.8	421.6	123.1	482.2	695.8	169.2	625.5	725.3	947.9	519.5	292.6	523.8	70.8	114.4
Optional Adder for Black Start ($M)	$M	0.5	1.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	6.25	N/A	N/A

North Jax Description	North Jax site will be located on part of the property made available by retirement of SJRPP. The site is expected to be in brownfield condition, with all surface structures and foundations removed.

EPC Cost Adjustments	Site Notes	Option-Specific Notes
Generation+Admin Building	Required	
Water	Interconnections for potable, service water, fire water cooling tower makeup and sanitary sewer are proximate and will not require significant off-site construction. Interconnection for cooling tower blowdown may require offsite construction.	
Groundwork	The site is expected to be in brownfield condition, with all surface structures and foundations removed.	
Fuel Oil Storage and Forwarding	Required	

Owner's Absolute Cost Allowances	Site Notes	Option-Specific Notes
Gas Supply	The current estimate for upgrading the gas delivery infrastructure to support at least 1000-1500MW of advanced class Frame CTs is in the range of $130M. This will be required for any resource options that cannot be run off the existing NGS supply of ~5200 mmBtu/hr @ 250 PSIG (including co-incident flow restrictions).	
Electrical Interconnect	Existing switchyard for (2) 660MW steam units will be retained and available for use. No offsite transmission upgrades will be required for ~1250 net MW of power offtake from the site, and potentially more when NS3 is retired.	
Permitting	Permitting will be starting over	

Owner's Relative Cost Allowances	Site Notes	Option-Specific Notes
Owner's Contingency	Recommendation requested	
Spare Parts	Required	
Owner's Project Management	Required	
Owner's Startup/Construction Support	Required	
Taxes/Advisory Fees/Legal	Assume covered property and tax law and interconnection agreements	
Project Development (selection, land purchase,	Assume covered site selection study, land cost, road mods, demolition, and	
Interest during construction	To be included in LCOE calculation	
Financing	To be included in LCOE calculation	

JEA Study
B&V Project Number 198807
LM6000 PF Sprint (25), Simple Cycle 2x0
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load	98 deg F 75% CTG Load	98 deg F 50% (MECL) CTG Load	69 deg F 100% CTG Load	69 deg F 75% CTG Load	69 deg F 25% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 25% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 25% (MECL) CTG Load
CTG Configuration	-	2x0	2x0	2x0	2x0	2x0	2x0	2x0	2x0	2x0	2x0	2x0	2x0
Heat Rejection System		-	-	-	-	-	-	-	-	-	-	-	-
Ambient Drybulb Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)	LM6000 PF Sprint (25)
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	75%	50% (MECL)	100%	75%	25% (MECL)	100%	75%	25% (MECL)	100%	75%	25% (MECL)
NEW & CLEAN PERFORMANCE													
Gross STG Output		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gross CTG Output (each)	kW	38,250	28,812	19,222	45,906	34,565	23,116	50,564	37,912	25,270	48,542	36,590	24,486
Gross CTG Heat Rate (LHV)	BTU/kWh	8,656	9,354	11,197	8,318	8,688	10,220	8,054	8,683	10,223	8,158	8,811	10,513
Gross CTG Heat Rate (HHV)	BTU/kWh	9,571	10,343	12,380	9,197	9,606	11,299	8,905	9,600	11,303	8,692	9,388	11,201
CTG Heat Input (LHV) each	MBtu/hr	331	270	215	382	300	236	407	329	258	396	322	257
CTG Heat Input (HHV) each	MBtu/hr	366	298	238	422	332	261	450	364	286	422	343	274
Total Plant Auxiliary Power	kW	1,217	1,075	932	1,418	1,162	990	1,585	1,212	1,022	1,571	1,391	1,210
Auxiliary Power & Losses as Percent of Gross	%	1.59%	1.87%	2.42%	1.54%	1.68%	2.14%	1.57%	1.60%	2.02%	1.62%	1.90%	2.47%
NET PLANT PERFORMANCE													
Net Plant Output	kW	75,282	56,549	37,513	90,395	67,968	45,242	99,544	74,613	49,518	95,514	71,788	47,763
Net Plant Heat Rate (LHV)	BTU/kWh	8,796	9,532	11,475	8,449	8,836	10,443	8,182	8,824	10,434	8,292	8,982	10,779
Net Plant Heat Rate (HHV)	BTU/kWh	9,726	10,540	12,687	9,341	9,770	11,547	9,046	9,756	11,537	8,835	9,570	11,485
Net Plant Efficiency (LHV)	%	38.79%	35.80%	29.74%	40.39%	38.61%	32.67%	41.70%	38.67%	32.70%	41.15%	37.99%	31.65%
Net Plant Efficiency (HHV)	%	35.08%	32.37%	26.89%	36.53%	34.92%	29.55%	37.72%	34.97%	29.58%	38.62%	35.66%	29.71%
STACK EMISSIONS													
NOx	ppmvd@15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.0098	0.0101	0.0102	0.0093	0.0091	0.0092	0.0091	0.0091	0.0093	0.0096	0.0096	0.0099
	lb/hr	3.6	3	2.4	3.9	3	2.4	4.1	3.3	2.7	4.1	3.3	2.7
CO	ppmvd@15% O2	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
	lb/MBtu (HHV)	0.0143	0.0147	0.0149	0.0136	0.0133	0.0134	0.0133	0.0133	0.0136	0.0140	0.0140	0.0144
	lb/hr	5.2	4.4	3.6	5.7	4.4	3.5	6	4.8	3.9	5.9	4.8	4
VOC	ppmvd@15% O2	2.8	2.8	5.6	2.1	2.1	5.6	2.1	2.1	5.6	8.4	8.4	8.4
	lb/MBtu (HHV)	0.0038	0.0039	0.0080	0.0027	0.0027	0.0072	0.0027	0.0027	0.0072	0.0112	0.0113	0.0115
	lb/hr	1.4	1.2	1.9	1.1	0.9	1.9	1.2	1	2.1	4.7	3.9	3.2
PM 2.5/10 - Front Half Only	lb/hr	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	7.5	7.3	7.1
PM 2.5/10 - Front Half and Back Half	lb/hr	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	14.0	13.8	13.6
CO2	lb/hr	43,741	35,590	28,417	50,438	39,653	31,201	53,798	43,490	34,135	69,049	56,228	44,874
NH3 Slip	lb/hr	4.9	4.0	3.2	5.7	4.5	3.5	6.1	4.9	3.8	3.0	2.4	1.9

JEA Study
B&V Project Number 198807
LMS100 PA+, Simple Cycle 1x0
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load	98 deg F 75% CTG Load	98 deg F 25% (MECL) CTG Load	69 deg F 100% CTG Load	69 deg F 75% CTG Load	69 deg F 25% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 25% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 25% (MECL) CTG Load
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Heat Rejection System		-	-	-	-	-	-	-	-	-	-	-	-
Ambient Drybulb Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+	LMS100 PA+
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	75%	25% (MECL)	100%	75%	25% (MECL)	100%	75%	25% (MECL)	100%	75%	25% (MECL)
NEW & CLEAN PERFORMANCE													
Gross STG Output		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gross CTG Output (each)	kW	94,234	70,800	23,736	114,510	86,250	28,993	118,037	88,667	29,623	112,866	85,024	28,590
Gross CTG Heat Rate (LHV)	BTU/kWh	8,097	8,676	12,873	7,804	8,211	11,849	7,704	8,126	11,738	7,841	8,315	12,033
Gross CTG Heat Rate (HHV)	BTU/kWh	8,952	9,592	14,233	8,628	9,078	13,101	8,518	8,985	12,979	8,354	8,859	12,820
CTG Heat Input (LHV) each	MBtu/hr	763	614	306	894	708	344	909	721	348	885	707	344
CTG Heat Input (HHV) each	MBtu/hr	844	679	338	988	783	380	1,005	797	384	943	753	367
Total Plant Auxiliary Power	kW	1,788	1,325	796	2,251	1,632	835	2,324	1,677	840	1,706	1,497	1,074
Auxiliary Power & Losses as Percent of Gross	%	1.90%	1.87%	3.35%	1.97%	1.89%	2.88%	1.97%	1.89%	2.83%	1.51%	1.76%	3.76%
NET PLANT PERFORMANCE													
Net Plant Output	kW	92,446	69,475	22,940	112,259	84,618	28,158	115,713	86,990	28,783	111,160	83,527	27,516
Net Plant Heat Rate (LHV)	BTU/kWh	8,253	8,841	13,319	7,960	8,369	12,200	7,859	8,283	12,081	7,961	8,464	12,502
Net Plant Heat Rate (HHV)	BTU/kWh	9,125	9,775	14,727	8,801	9,253	13,489	8,689	9,158	13,357	8,483	9,018	13,321
Net Plant Efficiency (LHV)	%	41.34%	38.59%	25.62%	42.87%	40.77%	27.97%	43.42%	41.19%	28.24%	42.86%	40.31%	27.29%
Net Plant Efficiency (HHV)	%	37.39%	34.91%	23.17%	38.77%	36.87%	25.30%	39.27%	37.26%	25.55%	40.22%	37.84%	25.62%
STACK EMISSIONS													
NOx	ppmvd@15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.0104	0.0102	0.0097	0.0102	0.0098	0.0092	0.0100	0.0097	0.0091	0.0101	0.0098	0.0096
	lb/hr	8.8	6.9	3.3	10	7.7	3.5	10	7.7	3.5	9.5	7.4	3.5
CO	ppmvd@15% O2	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
	lb/MBtu (HHV)	0.0151	0.0148	0.0142	0.0147	0.0143	0.0135	0.0145	0.0141	0.0133	0.0148	0.0144	0.0140
	lb/hr	12.8	10.1	4.8	14.6	11.2	5.1	14.6	11.2	5.1	13.9	10.8	5.1
VOC	ppmvd@15% O2	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	4.5	4.5	4.5
	lb/MBtu (HHV)	0.0020	0.0020	0.0019	0.0020	0.0019	0.0018	0.0019	0.0019	0.0018	0.0064	0.0062	0.0061
	lb/hr	1.7	1.4	0.6	2	1.5	0.7	2	1.5	0.7	6	4.7	2.2
PM 2.5/10 - Front Half Only	lb/hr	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	13.4	12.9	11.9
PM 2.5/10 - Front Half and Back Half	lb/hr	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	24.4	23.9	22.9
CO2	lb/hr	100,775	81,136	40,355	118,030	93,551	45,371	120,112	95,182	45,923	154,299	123,267	59,991
NH3 Slip	lb/hr	11.3	9.1	4.5	13.3	10.5	5.1	13.5	10.7	5.2	6.7	5.4	2.6

JEA Study
B&V Project Number 198807
7F.05, Simple Cycle 1x0
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load	98 deg F 75% CTG Load	98 deg F 44% (MECL) CTG Load	69 deg F 100% CTG Load	69 deg F 75% CTG Load	69 deg F 44% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 44% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 50% (MECL) CTG Load
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Heat Rejection System		-	-	-	-	-	-	-	-	-	-	-	-
Ambient Drybulb Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	75%	44% (MECL)	100%	75%	44% (MECL)	100%	75%	44% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE													
Gross STG Output		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gross CTG Output (each)	kW	214,735	161,051	94,483	231,885	173,914	102,029	240,210	180,157	105,692	240,210	180,158	120,105
Gross CTG Heat Rate (LHV)	BTU/kWh	8,926	9,399	12,014	8,839	9,145	11,568	8,670	9,039	11,513	9,053	9,554	11,066
Gross CTG Heat Rate (HHV)	BTU/kWh	9,904	10,429	13,331	9,808	10,147	12,836	9,620	10,030	12,775	9,646	10,180	11,791
CTG Heat Input (LHV) each	MBtu/hr	1,917	1,514	1,135	2,050	1,590	1,180	2,083	1,628	1,217	2,175	1,721	1,329
CTG Heat Input (HHV) each	MBtu/hr	2,127	1,680	1,260	2,274	1,765	1,310	2,311	1,807	1,350	2,317	1,834	1,416
Total Plant Auxiliary Power	kW	2,568	2,165	1,666	2,696	2,261	1,722	2,759	2,308	1,750	3,336	2,885	2,435
Auxiliary Power & Losses as Percent of Gross	%	1.20%	1.34%	1.76%	1.16%	1.30%	1.69%	1.15%	1.28%	1.66%	1.39%	1.60%	2.03%
NET PLANT PERFORMANCE													
Net Plant Output	kW	212,167	158,886	92,817	229,189	171,653	100,307	237,451	177,849	103,942	236,874	177,273	117,670
Net Plant Heat Rate (LHV)	BTU/kWh	9,034	9,527	12,230	8,943	9,265	11,767	8,771	9,156	11,707	9,180	9,709	11,295
Net Plant Heat Rate (HHV)	BTU/kWh	10,024	10,571	13,570	9,923	10,281	13,056	9,732	10,160	12,990	9,782	10,345	12,035
Net Plant Efficiency (LHV)	%	37.77%	35.82%	27.90%	38.15%	36.83%	29.00%	38.90%	37.27%	29.15%	37.17%	35.14%	30.21%
Net Plant Efficiency (HHV)	%	34.04%	32.28%	25.14%	34.39%	33.19%	26.13%	35.06%	33.58%	26.27%	34.88%	32.98%	28.35%
STACK EMISSIONS													
NOx	ppmvd@15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	42.0	42.0	42.0
	lb/MBtu (HHV)	0.0323	0.0323	0.0323	0.0325	0.0324	0.0325	0.0326	0.0325	0.0326	0.1640	0.1641	0.1638
	lb/hr	68.7	54.3	40.7	73.9	57.2	42.5	75.4	58.8	44	380	301	232
CO	ppmvd@15% O2	6.9	7.0	7.7	6.9	7.1	7.6	7.0	7.1	7.4	13.8	14.0	14.6
	lb/MBtu (HHV)	0.0150	0.0152	0.0169	0.0153	0.0156	0.0167	0.0158	0.0156	0.0164	0.0324	0.0332	0.0347
	lb/hr	31.9	25.6	21.3	34.7	27.5	21.9	36.6	28.2	22.2	75.1	60.9	49.1
VOC	ppmvd@15% O2	1.2	1.2	1.3	1.2	1.2	1.3	1.2	1.2	1.3	2.7	2.7	2.8
	lb/MBtu (HHV)	0.0015	0.0015	0.0017	0.0015	0.0015	0.0016	0.0015	0.0015	0.0016	0.0036	0.0037	0.0038
	lb/hr	3.2	2.6	2.1	3.4	2.7	2.1	3.5	2.7	2.1	8.4	6.8	5.4
PM 2.5/10 - Front Half Only	lb/hr	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	20.2	20.2	20.2
PM 2.5/10 - Front Half and Back Half	lb/hr	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	41.1	40.9	40.8
CO2	lb/hr	244,395	193,009	144,722	261,323	202,776	150,484	265,548	207,632	155,148	379,177	300,114	231,735
NH3 Slip	lb/hr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

JEA Study
B&V Project Number 198807
7F.05, 1x1, Wet Mech. Cooling Tower
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load Duct Fired	98 deg F 100% CTG Load Unfired	98 deg F 75% CTG Load Unfired	98 deg F 44% (MECL) CTG Load Unfired	69 deg F 100% CTG Load Duct Fired	69 deg F 100% CTG Load Unfired	69 deg F 75% CTG Load Unfired	69 deg F 44% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Duct Fired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 44% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 50% (MECL) CTG Load Unfired
CTG Configuration	-	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1
Heat Rejection System		Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05	7F.05
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	100%	75%	44% (MECL)	100%	100%	75%	44% (MECL)	100%	100%	75%	44% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE																
Gross STG Output	kW	129,495	112,602	91,777	76,976	136,846	118,996	94,194	79,218	126,821	110,277	90,949	78,422	108,204	91,897	77,702
Gross CTG Output (each)	kW	213,288	213,288	159,966	93,847	232,053	232,053	174,040	102,103	240,210	240,210	180,158	105,692	240,210	180,157	120,105
Gross CTG Heat Rate (LHV)	BTU/kWh	8,912	8,912	9,394	12,022	8,840	8,840	9,123	11,531	8,662	8,662	9,015	11,485	9,091	9,607	11,115
Gross CTG Heat Rate (HHV)	BTU/kWh	9,889	9,889	10,424	13,340	9,809	9,809	10,123	12,795	9,611	9,611	10,003	12,744	9,686	10,236	11,843
CTG Heat Input (LHV) each	MBtu/hr	1,901	1,901	1,503	1,128	2,051	2,051	1,588	1,177	2,081	2,081	1,624	1,214	2,184	1,731	1,335
CTG Heat Input (HHV) each	MBtu/hr	2,109	2,109	1,667	1,252	2,276	2,276	1,762	1,306	2,309	2,309	1,802	1,347	2,327	1,844	1,422
Total Plant Auxiliary Power	kW	9,243	8,961	8,232	7,515	9,504	9,201	8,369	7,621	9,158	8,865	7,926	7,212	9,387	8,514	7,889
Auxiliary Power & Losses as Percent of Gross	%	2.70%	2.75%	3.27%	4.40%	2.58%	2.62%	3.12%	4.20%	2.50%	2.53%	2.92%	3.92%	2.69%	3.13%	3.99%
NET PLANT PERFORMANCE																
Net Plant Output	kW	333,540	316,929	243,511	163,308	359,395	341,848	259,865	173,700	357,873	341,621	263,181	176,901	339,026	263,540	189,918
Net Plant Heat Rate (LHV)	BTU/kWh	6,066	5,998	6,171	6,909	6,076	6,001	6,110	6,778	6,161	6,091	6,171	6,862	6,441	6,567	7,029
Net Plant Heat Rate (HHV)	BTU/kWh	6,731	6,655	6,848	7,666	6,742	6,659	6,780	7,521	6,836	6,758	6,848	7,614	6,863	6,997	7,489
Net Plant Efficiency (LHV)	%	56.25%	56.89%	55.29%	49.39%	56.16%	56.86%	55.85%	50.34%	55.39%	56.02%	55.29%	49.73%	52.97%	51.96%	48.54%
Net Plant Efficiency (HHV)	%	50.69%	51.27%	49.83%	44.51%	50.61%	51.24%	50.33%	45.37%	49.92%	50.49%	49.83%	44.81%	49.72%	48.76%	45.56%
STACK EMISSIONS																
NOx	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0073	0.0073	0.0073	0.0078	0.0078	0.0078
	lb/hr	16.1	15.1	12	9	17.5	16.4	12.7	9.4	17.7	16.8	13.1	9.8	18.1	14.3	11
CO	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0043	0.0043	0.0044	0.0043	0.0043	0.0044	0.0045	0.0044	0.0043	0.0043	0.0045	0.0045	0.0046	0.0047	0.0047
	lb/hr	9.8	9.1	7.3	5.4	10.4	10	7.9	5.7	10.6	10	8.1	6	10.7	8.7	6.7
VOC	ppmvd@15% O2	1.6	1.0	1.0	1.0	1.6	1.0	1.0	1.0	1.6	1.0	1.0	1.0	1.9	1.9	2.0
	lb/MBtu (HHV)	0.0020	0.0012	0.0012	0.0012	0.0020	0.0012	0.0012	0.0013	0.0020	0.0012	0.0012	0.0013	0.0025	0.0026	0.0027
	lb/hr	4.5	2.6	2.1	1.5	4.9	2.7	2.2	1.7	4.8	2.8	2.2	1.7	5.8	4.7	3.8
PM 2.5/10 - Front Half Only	lb/hr	4.7	3.3	3.3	3.3	4.8	3.3	3.3	3.3	4.7	3.3	3.3	3.3	22.7	22.2	21.7
PM 2.5/10 - Front Half and Back Half	lb/hr	9.9	6.6	6.6	6.6	10.1	6.6	6.6	6.6	9.9	6.6	6.6	6.6	42.8	42.3	41.8
CO2	lb/hr	257,972	242,365	191,609	143,844	278,422	261,543	202,447	150,127	281,110	265,301	207,083	154,764	380,772	301,773	232,756
NH3 Slip	lb/hr	29.8	28.0	22.2	16.6	32.2	30.2	23.4	17.4	32.5	30.7	23.9	17.9	16.5	13.1	10.1

JEA Study
B&V Project Number 198807
7HA.01, Simple Cycle 1x0
Preliminary Performance Summary
Sept 11, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load	98 deg F 75% CTG Load	98 deg F 25% (MECL) CTG Load	69 deg F 100% CTG Load	69 deg F 75% CTG Load	69 deg F 23% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 25% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 50% (MECL) CTG Load
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Heat Rejection System		-	-	-	-	-	-	-	-	-	-	-	-
Ambient Drybulb Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	75%	25% (MECL)	100%	75%	23% (MECL)	100%	75%	25% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE													
Gross STG Output		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gross CTG Output (each)	kW	244,889	183,667	61,223	267,807	200,855	61,595	277,409	208,057	69,353	288,517	216,388	144,258
Gross CTG Heat Rate (LHV)	BTU/kWh	8,480	8,935	13,843	8,324	8,715	13,964	8,217	8,713	13,484	8,845	9,294	10,661
Gross CTG Heat Rate (HHV)	BTU/kWh	9,409	9,914	15,360	9,237	9,670	15,494	9,117	9,668	14,962	9,424	9,903	11,359
CTG Heat Input (LHV) each	MBtu/hr	2,077	1,641	847	2,229	1,750	860	2,279	1,813	935	2,552	2,011	1,538
CTG Heat Input (HHV) each	MBtu/hr	2,304	1,821	940	2,474	1,942	954	2,529	2,011	1,038	2,719	2,143	1,639
Total Plant Auxiliary Power	kW	2,867	2,408	1,490	3,039	2,537	1,492	3,111	2,591	1,551	3,965	3,424	2,883
Auxiliary Power & Losses as Percent of Gross	%	1.17%	1.31%	2.43%	1.13%	1.26%	2.42%	1.12%	1.25%	2.24%	1.37%	1.58%	2.00%
NET PLANT PERFORMANCE													
Net Plant Output	kW	242,022	181,259	59,733	264,768	198,318	60,103	274,298	205,466	67,802	284,552	212,964	141,375
Net Plant Heat Rate (LHV)	BTU/kWh	8,580	9,053	14,188	8,420	8,826	14,310	8,310	8,823	13,793	8,968	9,443	10,878
Net Plant Heat Rate (HHV)	BTU/kWh	9,521	10,046	15,743	9,343	9,794	15,879	9,221	9,790	15,305	9,556	10,062	11,591
Net Plant Efficiency (LHV)	%	39.77%	37.69%	24.05%	40.52%	38.66%	23.84%	41.06%	38.67%	24.74%	38.05%	36.13%	31.37%
Net Plant Efficiency (HHV)	%	35.84%	33.97%	21.67%	36.52%	34.84%	21.49%	37.01%	34.85%	22.29%	35.71%	33.91%	29.44%
STACK EMISSIONS													
NO_x	ppmvd@15% O_2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	42.0	42.0	42.0
	lb/MBtu (HHV)	0.0345	0.0346	0.0344	0.0344	0.0344	0.0347	0.0345	0.0345	0.0346	0.1633	0.1633	0.1636
	lb/hr	79.45107338	62.91374589	32.35564074	85.20318729	66.86832421	33.07465498	87.36023001	69.38487404	35.95071194	444	350	268
CO	ppmvd@15% O_2												
	lb/MBtu (HHV)												
	lb/hr												
VOC	ppmvd@15% O_2												
	lb/MBtu (HHV)												
	lb/hr												
PM 2.5/10 - Front Half Only	lb/hr												
PM 2.5/10 - Front Half and Back Half	lb/hr												
CO_2	lb/hr	280,719	221,841	114,551	301,350	236,609	116,277	308,118	245,047	126,414	444,973	350,665	268,157
NH_3 Slip	lb/hr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

JEA Study
B&V Project Number 198807
7HA.01, 1x1, Wet Mech. Cooling Tower
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load Duct Fired	98 deg F 100% CTG Load Unfired	98 deg F 75% CTG Load Unfired	98 deg F 25% (MECL) CTG Load Unfired	69 deg F 100% CTG Load Duct Fired	69 deg F 100% CTG Load Unfired	69 deg F 75% CTG Load Unfired	69 deg F 23% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Duct Fired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 25% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 50% (MECL) CTG Load Unfired
CTG Configuration	-	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1
Heat Rejection System		Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	100%	75%	25% (MECL)	100%	100%	75%	23% (MECL)	100%	100%	75%	25% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE																
Gross STG Output	kW	145,039	126,121	102,813	63,003	150,692	131,036	107,417	65,231	147,425	128,195	108,426	68,196	116,882	98,588	86,967
Gross CTG Output (each)	kW	259,854	259,854	194,890	64,964	286,036	286,036	214,527	65,788	302,769	302,769	227,077	75,692	294,917	221,188	147,459
Gross CTG Heat Rate (LHV)	BTU/kWh	8,392	8,392	8,840	13,695	8,199	8,199	8,606	13,765	8,098	8,098	8,550	13,132	8,884	9,295	10,627
Gross CTG Heat Rate (HHV)	BTU/kWh	9,312	9,312	9,809	15,196	9,098	9,098	9,549	15,274	8,986	8,986	9,487	14,571	9,466	9,904	11,323
CTG Heat Input (LHV) each	MBtu/hr	2,181	2,181	1,723	890	2,345	2,345	1,846	906	2,452	2,452	1,942	994	2,620	2,056	1,567
CTG Heat Input (HHV) each	MBtu/hr	2,420	2,420	1,912	987	2,602	2,602	2,049	1,005	2,721	2,721	2,154	1,103	2,792	2,191	1,670
Total Plant Auxiliary Power	kW	10,536	10,211	9,328	7,709	10,675	10,326	9,406	7,757	10,629	10,281	9,372	7,420	10,737	9,860	8,944
Auxiliary Power & Losses as Percent of Gross	%	2.60%	2.65%	3.13%	6.02%	2.44%	2.48%	2.92%	5.92%	2.36%	2.39%	2.79%	5.16%	2.61%	3.08%	3.82%
NET PLANT PERFORMANCE																
Net Plant Output	kW	394,356	375,764	288,375	120,258	426,053	406,747	312,539	123,261	439,565	420,683	326,131	136,468	401,062	309,916	225,482
Net Plant Heat Rate (LHV)	BTU/kWh	5,874	5,803	5,974	7,398	5,847	5,766	5,907	7,347	5,904	5,828	5,953	7,284	6,533	6,634	6,950
Net Plant Heat Rate (HHV)	BTU/kWh	6,518	6,439	6,629	8,209	6,488	6,398	6,555	8,152	6,551	6,467	6,606	8,082	6,961	7,068	7,405
Net Plant Efficiency (LHV)	%	58.08%	58.80%	57.11%	46.12%	58.36%	59.18%	57.76%	46.44%	57.79%	58.55%	57.32%	46.85%	52.23%	51.44%	49.10%
Net Plant Efficiency (HHV)	%	52.35%	52.99%	51.47%	41.57%	52.59%	53.33%	52.06%	41.86%	52.08%	52.76%	51.65%	42.22%	49.02%	48.27%	46.08%
STACK EMISSIONS																
NOx	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0073	0.0078	0.0078	0.0078
	lb/hr	18.6	17.5	13.8	7.1	20	18.8	14.8	7.3	20.8	19.7	15.6	8	21.7	17	13
CO	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0044	0.0044	0.0045	0.0046	0.0044	0.0045	0.0044	0.0045	0.0043	0.0044	0.0043	0.0043	0.0047	0.0047	0.0047
	lb/hr	11.2	10.6	8.6	4.5	12.1	11.6	9	4.5	12.4	12	9.3	4.8	13.1	10.2	7.9
VOC	ppmvd@15% O2	1.6	1.0	1.0	1.0	1.5	1.0	1.0	1.0	1.5	1.0	1.0	1.0	1.8	1.9	1.9
	lb/MBtu (HHV)	0.0020	0.0013	0.0012	0.0013	0.0019	0.0013	0.0012	0.0013	0.0019	0.0013	0.0012	0.0012	0.0025	0.0025	0.0026
	lb/hr	5.1	3.2	2.3	1.3	5.4	3.4	2.6	1.3	5.4	3.4	2.6	1.4	6.9	5.6	4.4
PM 2.5/10 - Front Half Only	lb/hr	5.2	3.7	3.7	3.7	5.3	3.7	3.7	3.7	5.3	3.7	3.7	3.7	28.3	27.7	27.1
PM 2.5/10 - Front Half and Back Half	lb/hr	11.0	7.4	7.4	7.4	11.3	7.4	7.4	7.4	11.2	7.4	7.4	7.4	53.6	53.0	52.4
CO2	lb/hr	295,362	278,031	219,676	113,446	317,613	299,019	235,397	115,476	330,908	312,627	247,550	126,725	456,837	358,479	273,228
NH3 Slip	lb/hr	34.2	32.2	25.4	13.1	36.7	34.6	27.2	13.4	38.3	36.2	28.6	14.7	19.8	15.6	11.9

JEA Study
B&V Project Number 198807
7HA.01, 2x1, Wet Mech. Cooling Tower
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F	98 deg F	98 deg F	98 deg F	69 deg F	69 deg F	69 deg F	69 deg F	24 deg F	24 deg F	24 deg F	24 deg F	24 deg F	24 deg F	24 deg F
		100% CTG Load	100% CTG Load	75% CTG Load	25% (MECL) CTG Load	100% CTG Load	100% CTG Load	75% CTG Load	23% (MECL) CTG Load	100% CTG Load	100% CTG Load	75% CTG Load	25% (MECL) CTG Load	100% CTG Load	75% CTG Load	50% (MECL) CTG Load
		Duct Fired	Unfired	Unfired	Unfired	Duct Fired	Unfired	Unfired	Unfired	Duct Fired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
CTG Configuration	-	2x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1
Heat Rejection System		Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.	Wet Mech.
		Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower	Cooling Tower
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01	7HA.01
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	100%	75%	25% (MECL)	100%	100%	75%	23% (MECL)	100%	100%	75%	25% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE																
Gross STG Output	kW	293,317	255,059	207,927	127,700	304,955	265,178	217,449	132,172	298,183	259,292	219,381	138,368	236,642	199,698	176,304
Gross CTG Output (each)	kW	259,854	259,854	194,890	64,964	286,036	286,036	214,527	65,788	302,769	302,769	227,077	75,692	294,917	221,188	147,459
Gross CTG Heat Rate (LHV)	BTU/kWh	8,392	8,392	8,840	13,695	8,199	8,199	8,606	13,765	8,098	8,098	8,550	13,132	8,884	9,295	10,627
Gross CTG Heat Rate (HHV)	BTU/kWh	9,312	9,312	9,809	15,196	9,098	9,098	9,549	15,274	8,986	8,986	9,487	14,571	9,466	9,904	11,323
CTG Heat Input (LHV) each	MBtu/hr	2,181	2,181	1,723	890	2,345	2,345	1,846	906	2,452	2,452	1,942	994	2,620	2,056	1,567
CTG Heat Input (HHV) each	MBtu/hr	2,420	2,420	1,912	987	2,602	2,602	2,049	1,005	2,721	2,721	2,154	1,103	2,792	2,191	1,670
Total Plant Auxiliary Power	kW	20,980	20,330	18,559	15,320	21,405	20,706	18,865	15,418	21,097	20,400	18,580	14,825	21,312	19,371	17,873
Auxiliary Power & Losses as Percent of Gross	%	2.58%	3.95%	4.61%	7.95%	3.62%	3.76%	4.37%	7.79%	3.51%	3.63%	4.16%	6.93%	4.01%	4.60%	5.52%
NET PLANT PERFORMANCE																
Net Plant Output	kW	792,045	754,436	579,148	242,308	855,622	816,544	627,638	248,330	882,624	844,431	654,955	274,927	805,164	622,703	453,349
Net Plant Heat Rate (LHV)	BTU/kWh	5,849	5,781	5,950	7,343	5,823	5,744	5,883	7,293	5,881	5,807	5,929	7,231	6,508	6,603	6,913
Net Plant Heat Rate (HHV)	BTU/kWh	6,491	6,415	6,602	8,148	6,461	6,374	6,528	8,093	6,525	6,444	6,579	8,024	6,934	7,036	7,366
Net Plant Efficiency (LHV)	%	58.33%	59.02%	57.35%	46.47%	58.60%	59.40%	58.00%	46.78%	58.02%	58.76%	57.55%	47.19%	52.43%	51.67%	49.36%
Net Plant Efficiency (HHV)	%	52.57%	53.19%	51.69%	41.88%	52.81%	53.53%	52.27%	42.16%	52.29%	52.95%	51.87%	42.53%	49.21%	48.50%	46.32%
STACK EMISSIONS																
NOx	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0073	0.0078	0.0078	0.0078
	lb/hr	19.7	17.5	13.8	7.1	21.1	18.8	14.8	7.3	22	19.7	15.6	8	21.7	17	13
CO	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0043	0.0044	0.0045	0.0046	0.0044	0.0045	0.0044	0.0045	0.0044	0.0044	0.0043	0.0043	0.0047	0.0047	0.0047
	lb/hr	11.8	10.6	8.6	4.5	12.8	11.6	9	4.5	13.4	12	9.3	4.8	13.1	10.2	7.9
VOC	ppmvd@15% O2	2.2	1.0	1.0	1.0	2.2	1.0	1.0	1.0	2.1	1.0	1.0	1.0	1.8	1.9	1.9
	lb/MBtu (HHV)	0.0028	0.0013	0.0012	0.0013	0.0028	0.0013	0.0012	0.0013	0.0026	0.0013	0.0013	0.0012	0.0025	0.0025	0.0026
	lb/hr	7.6	3.2	2.3	1.3	8.1	3.4	2.6	1.3	8	3.4	2.8	1.4	6.9	5.6	4.4
PM 2.5/10 - Front Half Only	lb/hr	6.7	3.7	3.7	3.7	6.9	3.7	3.7	3.7	6.9	3.7	3.7	3.7	28.3	27.7	27.1
PM 2.5/10 - Front Half and Back Half	lb/hr	14.6	7.4	7.4	7.4	15.2	7.4	7.4	7.4	15.0	7.4	7.4	7.4	53.6	53.0	52.4
CO2	lb/hr	312,660	278,031	219,676	113,446	336,203	299,019	235,397	115,476	349,207	312,627	247,550	126,725	456,837	358,479	273,228
NH3 Slip	lb/hr	36.2	32.2	25.4	13.1	38.9	34.6	27.2	13.4	40.4	36.2	28.6	14.7	19.8	15.6	11.9

JEA Study
B&V Project Number 198807
7HA.02, Simple Cycle 1x0
Preliminary Performance Summary
Sept 11, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load	98 deg F 75% CTG Load	98 deg F 33% (MECL) CTG Load	69 deg F 100% CTG Load	69 deg F 75% CTG Load	69 deg F 30% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 31% (MECL) CTG Load	24 deg F 100% CTG Load	24 deg F 75% CTG Load	24 deg F 50% (MECL) CTG Load
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Heat Rejection System		-	-	-	-	-	-	-	-	-	-	-	-
Ambient Drybulb Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	75%	33% (MECL)	100%	75%	30% (MECL)	100%	75%	31% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE													
Gross STG Output		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gross CTG Output (each)	kW	325,505	244,129	107,417	354,100	265,574	106,230	365,116	273,837	113,186	392,612	294,459	196,306
Gross CTG Heat Rate (LHV)	BTU/kWh	8,418	8,804	11,783	8,304	8,622	11,908	8,172	8,574	11,815	8,639	9,070	10,387
Gross CTG Heat Rate (HHV)	BTU/kWh	9,341	9,769	13,075	9,215	9,567	13,214	9,068	9,513	13,110	9,205	9,664	11,067
CTG Heat Input (LHV) each	MBtu/hr	2,740	2,149	1,266	2,941	2,290	1,265	2,984	2,348	1,337	3,392	2,671	2,039
CTG Heat Input (HHV) each	MBtu/hr	3,041	2,385	1,404	3,263	2,541	1,404	3,311	2,605	1,484	3,614	2,846	2,173
Total Plant Auxiliary Power	kW	3,477	2,867	1,841	3,691	3,027	1,832	3,774	3,089	1,885	4,746	4,009	3,273
Auxiliary Power & Losses as Percent of Gross	%	1.07%	1.17%	1.71%	1.04%	1.14%	1.72%	1.03%	1.13%	1.67%	1.21%	1.36%	1.67%
NET PLANT PERFORMANCE													
Net Plant Output	kW	322,028	241,262	105,576	350,408	262,547	104,397	361,342	270,748	111,301	387,866	290,450	193,033
Net Plant Heat Rate (LHV)	BTU/kWh	8,509	8,909	11,989	8,392	8,722	12,117	8,258	8,671	12,015	8,745	9,195	10,563
Net Plant Heat Rate (HHV)	BTU/kWh	9,442	9,885	13,303	9,312	9,678	13,446	9,163	9,622	13,332	9,317	9,797	11,255
Net Plant Efficiency (LHV)	%	40.10%	38.30%	28.46%	40.66%	39.12%	28.16%	41.32%	39.35%	28.40%	39.02%	37.11%	32.30%
Net Plant Efficiency (HHV)	%	36.14%	34.52%	25.65%	36.64%	35.26%	25.38%	37.24%	35.46%	25.59%	36.62%	34.83%	30.32%
STACK EMISSIONS													
NOx	ppmvd@15% O2	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	42.0	42.0	42.0
	lb/MBtu (HHV)	0.0339	0.0339	0.0339	0.0339	0.0340	0.0339	0.0340	0.0340	0.0340	0.1633	0.1634	0.1634
	lb/hr	103.1444167	80.93971588	47.63266466	110.6653638	86.31182092	47.63266466	112.4560654	88.46066294	50.49778734	590	465	355
CO	ppmvd@15% O2												
	lb/MBtu (HHV)												
	lb/hr												
VOC	ppmvd@15% O2												
	lb/MBtu (HHV)												
	lb/hr												
PM 2.5/10 - Front Half Only	lb/hr												
PM 2.5/10 - Front Half and Back Half	lb/hr												
CO2	lb/hr	364,699	286,066	168,457	391,366	304,763	168,376	397,124	312,460	177,983	591,394	465,671	355,544
NH3 Slip	lb/hr	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

JEA Study
B&V Project Number 198807
7HA.02, 1x1, Wet Mech. Cooling Tower
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load Duct Fired	98 deg F 100% CTG Load Unfired	98 deg F 75% CTG Load Unfired	98 deg F 33% (MECL) CTG Load Unfired	69 deg F 100% CTG Load Duct Fired	69 deg F 100% CTG Load Unfired	69 deg F 75% CTG Load Unfired	69 deg F 30% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Duct Fired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 30% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 50% (MECL) CTG Load Unfired
CTG Configuration	-	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1
Heat Rejection System		Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	100%	75%	33% (MECL)	100%	100%	75%	30% (MECL)	100%	100%	75%	30% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE																
Gross STG Output	kW	190,176	165,370	133,441	89,317	197,899	172,086	139,355	90,391	191,978	166,937	138,108	91,702	155,870	133,192	114,061
Gross CTG Output (each)	kW	344,391	344,391	258,293	113,649	375,469	375,469	281,602	112,641	395,138	395,138	296,354	118,542	393,794	295,346	196,897
Gross CTG Heat Rate (LHV)	BTU/kWh	8,256	8,256	8,639	11,559	8,125	8,125	8,456	11,670	8,019	8,019	8,370	11,650	8,682	9,114	10,425
Gross CTG Heat Rate (HHV)	BTU/kWh	9,161	9,161	9,586	12,826	9,016	9,016	9,383	12,949	8,898	8,898	9,287	12,927	9,251	9,711	11,108
CTG Heat Input (LHV) each	MBtu/hr	2,843	2,843	2,231	1,314	3,051	3,051	2,381	1,315	3,169	3,169	2,480	1,381	3,419	2,692	2,053
CTG Heat Input (HHV) each	MBtu/hr	3,155	3,155	2,476	1,458	3,385	3,385	2,642	1,459	3,516	3,516	2,752	1,532	3,643	2,868	2,187
Total Plant Auxiliary Power	kW	13,790	13,357	12,168	10,363	13,983	13,529	12,293	10,206	13,734	13,274	12,021	9,942	13,960	12,795	11,798
Auxiliary Power & Losses as Percent of Gross	%	2.58%	2.62%	3.11%	5.11%	2.44%	2.47%	2.92%	5.03%	2.34%	2.36%	2.77%	4.73%	2.54%	2.99%	3.79%
NET PLANT PERFORMANCE																
Net Plant Output	kW	520,777	496,404	379,566	192,603	559,385	534,026	408,663	192,825	573,382	548,801	422,441	200,302	535,704	415,743	299,160
Net Plant Heat Rate (LHV)	BTU/kWh	5,803	5,728	5,879	6,821	5,788	5,713	5,827	6,817	5,853	5,774	5,872	6,895	6,382	6,475	6,861
Net Plant Heat Rate (HHV)	BTU/kWh	6,439	6,356	6,523	7,568	6,423	6,339	6,466	7,564	6,494	6,407	6,515	7,650	6,800	6,899	7,311
Net Plant Efficiency (LHV)	%	58.80%	59.57%	58.04%	50.03%	58.95%	59.73%	58.56%	50.05%	58.30%	59.10%	58.11%	49.49%	53.46%	52.70%	49.73%
Net Plant Efficiency (HHV)	%	52.99%	53.69%	52.31%	45.09%	53.12%	53.83%	52.77%	45.11%	52.54%	53.26%	52.37%	44.60%	50.18%	49.46%	46.67%
STACK EMISSIONS																
NOx	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0078	0.0078	0.0078
	lb/hr	24.2	22.8	17.9	10.6	26	24.5	19.1	10.6	26.9	25.4	19.9	11	28.3	22.3	17
CO	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0043	0.0043	0.0044	0.0043	0.0044	0.0043	0.0048	0.0046	0.0047
	lb/hr	14.7	13.8	10.9	6.5	15.8	14.8	11.5	6.3	16.4	15.2	12.1	6.6	17.3	13.3	10.4
VOC	ppmvd@15% O2	1.5	1.0	1.0	1.0	1.5	1.0	1.0	1.0	1.5	1.0	1.0	1.0	3.4	3.5	3.6
	lb/MBtu (HHV)	0.0019	0.0013	0.0013	0.0013	0.0019	0.0012	0.0012	0.0013	0.0018	0.0012	0.0012	0.0013	0.0046	0.0047	0.0048
	lb/hr	6.4	4	3.2	1.9	6.7	4.1	3.3	1.9	6.8	4.3	3.4	1.9	16.8	13.5	10.6
PM 2.5/10 - Front Half Only	lb/hr	7.9	5.9	5.9	5.9	8.0	5.9	5.9	5.9	8.0	5.9	5.9	5.9	44.9	44.1	43.4
PM 2.5/10 - Front Half and Back Half	lb/hr	16.6	11.8	11.8	11.8	16.8	11.8	11.8	11.8	16.8	11.8	11.8	11.8	85.9	85.1	84.4
CO2	lb/hr	385,310	362,533	284,506	167,494	412,861	388,980	303,601	167,603	427,877	404,015	316,276	176,081	596,146	469,339	357,904
NH3 Slip	lb/hr	44.6	41.9	32.9	19.4	47.7	45.0	35.1	19.4	49.5	46.7	36.6	20.4	25.9	20.4	15.5

JEA Study
B&V Project Number 198807
7HA.02, 2x1, Wet Mech. Cooling Tower
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load Duct Fired	98 deg F 100% CTG Load Unfired	98 deg F 75% CTG Load Unfired	98 deg F 33% (MECL) CTG Load Unfired	69 deg F 100% CTG Load Duct Fired	69 deg F 100% CTG Load Unfired	69 deg F 75% CTG Load Unfired	69 deg F 30% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Duct Fired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 30% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 50% (MECL) CTG Load Unfired
CTG Configuration	-	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1
Heat Rejection System		Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	100%	75%	33% (MECL)	100%	100%	75%	30% (MECL)	100%	100%	75%	30% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE																
Gross STG Output	kW	383,894	333,820	269,394	180,613	399,658	347,530	281,534	183,051	387,756	337,178	278,744	185,684	314,595	269,158	230,934
Gross CTG Output (each)	kW	344,391	344,391	258,293	113,649	375,469	375,469	281,602	112,641	395,138	395,138	296,354	118,542	393,794	295,346	196,897
Gross CTG Heat Rate (LHV)	BTU/kWh	8,256	8,256	8,639	11,559	8,125	8,125	8,456	11,670	8,019	8,019	8,370	11,650	8,682	9,114	10,425
Gross CTG Heat Rate (HHV)	BTU/kWh	9,161	9,161	9,586	12,826	9,016	9,016	9,383	12,949	8,898	8,898	9,287	12,927	9,251	9,711	11,108
CTG Heat Input (LHV) each	MBtu/hr	2,843	2,843	2,231	1,314	3,051	3,051	2,381	1,315	3,169	3,169	2,480	1,381	3,419	2,692	2,053
CTG Heat Input (HHV) each	MBtu/hr	3,155	3,155	2,476	1,458	3,385	3,385	2,642	1,459	3,516	3,516	2,752	1,532	3,643	2,868	2,187
Total Plant Auxiliary Power	kW	27,445	26,574	24,197	20,583	27,987	27,082	24,607	20,432	27,434	26,514	23,808	19,648	27,687	25,361	23,367
Auxiliary Power & Losses as Percent of Gross	%	2.56%	2.60%	3.08%	5.05%	2.43%	2.47%	2.91%	5.00%	2.33%	2.35%	2.73%	4.65%	2.51%	2.95%	3.74%
NET PLANT PERFORMANCE																
Net Plant Output	kW	1,045,231	996,028	761,782	387,328	1,122,609	1,071,387	820,131	387,901	1,150,598	1,100,940	847,644	403,120	1,074,496	834,488	601,361
Net Plant Heat Rate (LHV)	BTU/kWh	5,782	5,709	5,858	6,783	5,769	5,695	5,807	6,778	5,832	5,756	5,853	6,852	6,364	6,451	6,827
Net Plant Heat Rate (HHV)	BTU/kWh	6,416	6,335	6,501	7,527	6,401	6,319	6,443	7,521	6,471	6,387	6,494	7,603	6,780	6,874	7,274
Net Plant Efficiency (LHV)	%	59.01%	59.77%	58.24%	50.30%	59.15%	59.92%	58.76%	50.34%	58.51%	59.28%	58.30%	49.80%	53.62%	52.89%	49.98%
Net Plant Efficiency (HHV)	%	53.18%	53.86%	52.49%	45.33%	53.31%	54.00%	52.96%	45.37%	52.73%	53.42%	52.54%	44.88%	50.32%	49.64%	46.91%
STACK EMISSIONS																
NOx	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0078	0.0078	0.0078
	lb/hr	25.6	22.8	17.9	10.6	27.5	24.5	19.1	10.6	28.4	25.4	19.9	11	28.3	22.3	17
CO	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0044	0.0044	0.0044	0.0044	0.0043	0.0044	0.0043	0.0043	0.0043	0.0043	0.0044	0.0043	0.0048	0.0046	0.0047
	lb/hr	15.5	13.8	10.9	6.5	16.5	14.8	11.5	6.3	17	15.2	12.1	6.6	17.3	13.3	10.4
VOC	ppmvd@15% O2	2.2	1.0	1.0	1.0	2.1	1.0	1.0	1.0	2.1	1.0	1.0	1.0	3.4	3.5	3.6
	lb/MBtu (HHV)	0.0027	0.0013	0.0013	0.0013	0.0027	0.0012	0.0012	0.0013	0.0026	0.0012	0.0012	0.0013	0.0046	0.0047	0.0048
	lb/hr	9.7	4	3.2	1.9	10.2	4.1	3.3	1.9	10.3	4.3	3.4	1.9	16.8	13.5	10.6
PM 2.5/10 - Front Half Only	lb/hr	9.9	5.9	5.9	5.9	10.1	5.9	5.9	5.9	10.0	5.9	5.9	5.9	44.9	44.1	43.4
PM 2.5/10 - Front Half and Back Half	lb/hr	21.3	11.8	11.8	11.8	21.8	11.8	11.8	11.8	21.7	11.8	11.8	11.8	85.9	85.1	84.4
CO2	lb/hr	408,045	362,533	284,506	167,494	436,735	388,980	303,601	167,603	451,521	404,015	316,276	176,081	596,146	469,339	357,904
NH3 Slip	lb/hr	47.2	41.9	32.9	19.4	50.5	45.0	35.1	19.4	52.2	46.7	36.6	20.4	25.9	20.4	15.5

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Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load Duct Fired	98 deg F 100% CTG Load Unfired	98 deg F 75% CTG Load Unfired	98 deg F 33% (MECL) CTG Load Unfired	69 deg F 100% CTG Load Duct Fired	69 deg F 100% CTG Load Unfired	69 deg F 75% CTG Load Unfired	69 deg F 30% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Duct Fired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 30% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 50% (MECL) CTG Load Unfired
CTG Configuration	-	3x1	3x1	3x1	3x1	3x1	3x1	3x1	3x1	3x1	3x1	3x1	3x1	3x1	3x1	3x1
Heat Rejection System		Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower	Wet Mech. Cooling Tower
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	100%	75%	33% (MECL)	100%	100%	75%	30% (MECL)	100%	100%	75%	30% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE																
Gross STG Output	kW	579,320	503,755	406,476	272,738	604,127	525,327	425,414	276,960	586,161	509,702	421,707	280,911	476,022	406,800	349,008
Gross CTG Output (each)	kW	344,391	344,391	258,293	113,649	375,469	375,469	281,602	112,641	395,138	395,138	296,354	118,542	393,794	295,346	196,897
Gross CTG Heat Rate (LHV)	BTU/kWh	8,256	8,256	8,639	11,559	8,125	8,125	8,456	11,670	8,019	8,019	8,370	11,650	8,682	9,114	10,425
Gross CTG Heat Rate (HHV)	BTU/kWh	9,161	9,161	9,586	12,826	9,016	9,016	9,383	12,949	8,898	8,898	9,287	12,927	9,251	9,711	11,108
CTG Heat Input (LHV) each	MBtu/hr	2,843	2,843	2,231	1,314	3,051	3,051	2,381	1,315	3,169	3,169	2,480	1,381	3,419	2,692	2,053
CTG Heat Input (HHV) each	MBtu/hr	3,155	3,155	2,476	1,458	3,385	3,385	2,642	1,459	3,516	3,516	2,752	1,532	3,643	2,868	2,187
Total Plant Auxiliary Power	kW	41,159	39,848	36,283	30,867	41,895	40,530	36,815	30,922	41,102	39,713	35,952	29,519	41,774	38,093	35,099
Auxiliary Power & Losses as Percent of Gross	%	2.55%	2.59%	3.07%	5.03%	2.42%	2.45%	2.90%	5.03%	2.32%	2.34%	2.74%	4.64%	2.52%	2.95%	3.74%
NET PLANT PERFORMANCE																
Net Plant Output	kW	1,571,335	1,497,080	1,145,072	582,818	1,688,640	1,611,204	1,233,405	583,961	1,730,472	1,655,404	1,274,817	607,019	1,615,630	1,254,745	904,600
Net Plant Heat Rate (LHV)	BTU/kWh	5,769	5,698	5,846	6,762	5,752	5,680	5,792	6,753	5,817	5,742	5,837	6,825	6,348	6,436	6,807
Net Plant Heat Rate (HHV)	BTU/kWh	6,401	6,322	6,487	7,503	6,383	6,303	6,427	7,493	6,455	6,372	6,477	7,573	6,764	6,857	7,253
Net Plant Efficiency (LHV)	%	59.15%	59.89%	58.37%	50.46%	59.32%	60.07%	58.91%	50.53%	58.66%	59.42%	58.45%	49.99%	53.75%	53.02%	50.12%
Net Plant Efficiency (HHV)	%	53.31%	53.97%	52.60%	45.48%	53.46%	54.14%	53.09%	45.54%	52.86%	53.55%	52.68%	45.05%	50.44%	49.76%	47.04%
STACK EMISSIONS																
NOx	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0078	0.0078	0.0078
	lb/hr	27.1	22.8	17.9	10.6	29	24.5	19.1	10.6	29.9	25.4	19.9	11	28.3	22.3	17
CO	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0044	0.0044	0.0044	0.0044	0.0043	0.0044	0.0043	0.0043	0.0043	0.0043	0.0044	0.0043	0.0048	0.0046	0.0047
	lb/hr	16.3	13.8	10.9	6.5	17.4	14.8	11.5	6.3	17.8	15.2	12.1	6.6	17.3	13.3	10.4
VOC	ppmvd@15% O2	2.8	1.0	1.0	1.0	2.7	1.0	1.0	1.0	2.7	1.0	1.0	1.0	3.4	3.5	3.6
	lb/MBtu (HHV)	0.0035	0.0013	0.0013	0.0013	0.0034	0.0012	0.0012	0.0013	0.0033	0.0012	0.0012	0.0013	0.0046	0.0047	0.0048
	lb/hr	13	4	3.2	1.9	13.7	4.1	3.3	1.9	13.8	4.3	3.4	1.9	16.8	13.5	10.6
PM 2.5/10 - Front Half Only	lb/hr	11.8	5.9	5.9	5.9	12.1	5.9	5.9	5.9	12.1	5.9	5.9	5.9	44.9	44.1	43.4
PM 2.5/10 - Front Half and Back Half	lb/hr	26.0	11.8	11.8	11.8	26.7	11.8	11.8	11.8	26.7	11.8	11.8	11.8	85.9	85.1	84.4
CO2	lb/hr	430,699	362,533	284,506	167,494	460,537	388,980	303,601	167,603	475,473	404,015	316,276	176,081	596,146	469,339	357,904
NH3 Slip	lb/hr	49.8	41.9	32.9	19.4	53.3	45.0	35.1	19.4	55.0	46.7	36.6	20.4	25.9	20.4	15.5

JEA Study
B&V Project Number 198807
7HA.02, 1x1, Air Cooled Condenser
Preliminary Performance Summary
Sept 7, 2018 - Rev 1

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Revision #		Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1	Rev 1
Description		98 deg F 100% CTG Load Duct Fired	98 deg F 100% CTG Load Unfired	98 deg F 75% CTG Load Unfired	98 deg F 33% (MECL) CTG Load Unfired	69 deg F 100% CTG Load Duct Fired	69 deg F 100% CTG Load Unfired	69 deg F 75% CTG Load Unfired	69 deg F 30% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Duct Fired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 30% (MECL) CTG Load Unfired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F 50% (MECL) CTG Load Unfired
CTG Configuration	-	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1
Heat Rejection System		Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser	Air Cooled Condenser
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	70.0	70.0	70.0	70.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
CTG Model	-	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02	7HA.02
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Distillate	Distillate	Distillate
CTG Load Level		100%	100%	75%	33% (MECL)	100%	100%	75%	30% (MECL)	100%	100%	75%	30% (MECL)	100%	75%	50% (MECL)
NEW & CLEAN PERFORMANCE																
Gross STG Output	kW	183,205	159,308	128,795	86,480	191,216	166,276	134,620	87,218	185,493	161,299	133,542	86,979	150,831	129,085	110,459
Gross CTG Output (each)	kW	344,391	344,391	258,293	113,649	375,469	375,469	281,602	112,641	395,138	395,138	296,354	118,542	393,794	295,346	196,897
Gross CTG Heat Rate (LHV)	BTU/kWh	8,256	8,256	8,639	11,559	8,125	8,125	8,456	11,670	8,019	8,019	8,370	11,650	8,682	9,114	10,425
Gross CTG Heat Rate (HHV)	BTU/kWh	9,161	9,161	9,586	12,826	9,016	9,016	9,383	12,949	8,898	8,898	9,287	12,927	9,251	9,711	11,108
CTG Heat Input (LHV) each	MBtu/hr	2,843	2,843	2,231	1,314	3,051	3,051	2,381	1,315	3,169	3,169	2,480	1,381	3,419	2,692	2,053
CTG Heat Input (HHV) each	MBtu/hr	3,155	3,155	2,476	1,458	3,385	3,385	2,642	1,459	3,516	3,516	2,752	1,532	3,643	2,868	2,187
Total Plant Auxiliary Power	kW	13,681	13,240	12,038	10,213	13,010	12,550	11,122	8,749	12,156	11,602	10,244	7,778	12,282	10,926	9,835
Auxiliary Power & Losses as Percent of Gross	%	2.59%	2.63%	3.11%	5.10%	2.30%	2.32%	2.67%	4.38%	2.09%	2.08%	2.38%	3.78%	2.26%	2.57%	3.20%
NET PLANT PERFORMANCE																
Net Plant Output	kW	513,915	490,459	375,050	189,916	553,675	529,195	405,100	191,110	568,475	544,835	419,652	197,744	532,343	413,505	297,521
Net Plant Heat Rate (LHV)	BTU/kWh	5,879	5,797	5,950	6,917	5,846	5,765	5,878	6,878	5,900	5,816	5,911	6,984	6,422	6,510	6,899
Net Plant Heat Rate (HHV)	BTU/kWh	6,524	6,433	6,602	7,675	6,487	6,397	6,522	7,632	6,546	6,453	6,559	7,749	6,843	6,936	7,351
Net Plant Efficiency (LHV)	%	58.04%	58.86%	57.35%	49.33%	58.37%	59.19%	58.05%	49.61%	57.84%	58.67%	57.73%	48.86%	53.13%	52.42%	49.46%
Net Plant Efficiency (HHV)	%	52.30%	53.04%	51.69%	44.46%	52.60%	53.34%	52.31%	44.71%	52.12%	52.88%	52.02%	44.03%	49.86%	49.19%	46.42%
STACK EMISSIONS																
NOx	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0078	0.0078	0.0078
	lb/hr	24.2	22.8	17.9	10.6	26	24.5	19.1	10.6	26.9	25.4	19.9	11	28.3	22.3	17
CO	ppmvd@15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MBtu (HHV)	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0043	0.0043	0.0044	0.0043	0.0044	0.0043	0.0048	0.0046	0.0047
	lb/hr	14.7	13.8	10.9	6.5	15.7	14.8	11.5	6.3	16.4	15.2	12.1	6.6	17.3	13.3	10.4
VOC	ppmvd@15% O2	1.5	1.0	1.0	1.0	1.5	1.0	1.0	1.0	1.5	1.0	1.0	1.0	3.4	3.5	3.6
	lb/MBtu (HHV)	0.0019	0.0013	0.0013	0.0013	0.0019	0.0012	0.0012	0.0013	0.0018	0.0012	0.0012	0.0013	0.0046	0.0047	0.0048
	lb/hr	6.4	4	3.2	1.9	6.7	4.1	3.3	1.9	6.8	4.3	3.4	1.9	16.8	13.5	10.6
PM 2.5/10 - Front Half Only	lb/hr	7.9	5.9	5.9	5.9	8.0	5.9	5.9	5.9	8.0	5.9	5.9	5.9	44.9	44.1	43.4
PM 2.5/10 - Front Half and Back Half	lb/hr	16.5	11.8	11.8	11.8	16.8	11.8	11.8	11.8	16.7	11.8	11.8	11.8	85.9	85.1	84.4
CO2	lb/hr	385,252	362,533	284,506	167,494	412,722	388,980	303,601	167,603	427,620	404,015	316,276	176,081	596,146	469,339	357,904
NH3 Slip	lb/hr	44.6	41.9	32.9	19.4	47.7	45.0	35.1	19.4	49.5	46.7	36.6	20.4	25.9	20.4	15.5

Brandy Branch - Upgraded CTGs
2x1 Combined Cycle
7F.03 Upgraded w .05 Compressor & AGP Upgrade, Wet Mech. Cooling Tower
Preliminary Performance Summary
September 21, 2018

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13
Revision #		1	1	1	1	1	1	1	1	1	1	1	1	1
Description		98 deg F 100% CTG Load Duct Fired	98 deg F 100% CTG Load Unfired	98 deg F 75% CTG Load Unfired	98 deg F MECL% CTG Load Unfired	69 deg F 100% CTG Load Duct Fired	69 deg F 100% CTG Load Unfired	69 deg F 75% CTG Load Unfired	69 deg F MECL% CTG Load Unfired	24 deg F 100% CTG Load Duct Fired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F MECL% CTG Load Unfired	24 deg F 100% CTG Load Unfired
CTG Configuration	-	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1	2x1
Heat Rejection System														
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
CTG Model	-	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Fuel Oil
CTG Load Level		100	100	75	MECL	100	100	75	MECL	100	100	75	MECL	100
NEW & CLEAN PERFORMANCE														
Gross STG Output	kW	236,180	205,374	171,808	147,017	247,496	215,214	181,869	152,711	249,008	216,529	183,867	155,900	205,161
Gross CTG Output (each)	kW	187,667	187,667	140,751	93,834	202,621	202,621	151,965	101,310	213,120	213,120	159,840	106,560	203,605
Gross CTG Heat Rate (LHV)	BTU/kWh	9,276	9,276	9,830	11,628	9,055	9,055	9,594	11,103	8,980	8,980	9,578	11,068	9,820
Gross CTG Heat Rate (HHV)	BTU/kWh	10,282	10,282	10,897	12,890	10,037	10,037	10,635	12,308	9,955	9,955	10,618	12,269	10,547
CTG Heat Input (LHV) each	MBtu/hr	1,741	1,741	1,384	1,091	1,835	1,835	1,458	1,125	1,914	1,914	1,531	1,179	1,999
CTG Heat Input (HHV) each	MBtu/hr	1,930	1,930	1,534	1,210	2,034	2,034	1,616	1,247	2,122	2,122	1,697	1,307	2,147
Total Plant Auxiliary Power	kW	14,333	13,481	11,953	10,711	14,712	13,850	12,285	10,903	14,942	14,070	12,515	11,133	14,393
Auxiliary Power & Losses as Percent of Gross	%	2.34%	2.32%	2.64%	3.20%	2.34%	2.23%	2.53%	3.07%	2.34%	2.19%	2.49%	3.02%	2.35%
NET PLANT PERFORMANCE														
Net Plant Output	kW	597,182	567,227	441,356	323,973	638,025	606,605	473,514	344,428	660,306	628,699	491,032	357,886	597,979
Net Plant Heat Rate (LHV)	BTU/kWh	6,227	6,138	6,269	6,736	6,151	6,049	6,158	6,532	6,189	6,088	6,236	6,591	6,687
Net Plant Heat Rate (HHV)	BTU/kWh	6,887	6,804	6,950	7,467	6,803	6,705	6,826	7,241	6,844	6,749	6,913	7,306	7,183
Net Plant Efficiency (LHV)	%	54.83%	55.59%	54.42%	50.66%	55.50%	56.41%	55.41%	52.24%	55.17%	56.04%	54.72%	51.77%	51.03%
Net Plant Efficiency (HHV)	%	49.58%	50.15%	49.10%	45.70%	50.19%	50.89%	49.98%	47.13%	49.88%	50.56%	49.36%	46.70%	47.51%
STACK EMISSIONS														
NOx	ppmvd@15% O2													
	lb/MBtu (HHV)													
	lb/hr													
CO	ppmvd@15% O2													
	lb/MBtu (HHV)													
	lb/hr													
VOC	ppmvd@15% O2													
	lb/MBtu (HHV)													
	lb/hr													
PM 2.5/10 - Front Half Only	lb/hr													
PM 2.5/10 - Front Half and Back Half	lb/hr													
CO2	lb/hr													
NH3 Slip	lb/hr													

Brandy Branch - Upgraded CTGs
1x1 Combined Cycle
7F.03 Upgraded w .05 Compressor & AGP Upgrade, Wet Mech. Cooling Tower
Preliminary Performance Summary
September 21, 2018

Case #	Units	1	2	3	4	5	6	7	8	9	10	11	12	13
Revision #		1	1	1	1	1	1	1	1	1	1	1	1	1
Description		98 deg F 100% CTG Load Duct Fired	98 deg F 100% CTG Load Unfired	98 deg F 75% CTG Load Unfired	98 deg F MECL% CTG Load Unfired	69 deg F 100% CTG Load Duct Fired	69 deg F 100% CTG Load Unfired	69 deg F 75% CTG Load Unfired	69 deg F MECL% CTG Load Unfired	24 deg F 100% CTG Load Duct Fired	24 deg F 100% CTG Load Unfired	24 deg F 75% CTG Load Unfired	24 deg F MECL% CTG Load Unfired	24 deg F 100% CTG Load Unfired
CTG Configuration	-	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1	1x1
Heat Rejection System														
Ambient Drybulb Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
CTG Compressor Inlet Air Temperature	F	98.0	98.0	98.0	98.0	69.0	69.0	69.0	69.0	24.0	24.0	24.0	24.0	24.0
Barometric Pressure	psia	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70	14.70
CTG Model	-	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech	GE 7F.05 Hybrid Tech
CTG Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Fuel Oil
CTG Load Level		100	100	75	MECL	100	100	75	MECL	100	100	75	MECL	100
NEW & CLEAN PERFORMANCE														
Gross STG Output	kW	116,732	101,506	84,916	72,663	122,325	106,370	89,889	75,477	123,072	107,019	90,876	77,054	101,401
Gross CTG Output (each)	kW	187,667	187,667	140,751	93,834	202,621	202,621	151,965	101,310	213,120	213,120	159,840	106,560	203,605
Gross CTG Heat Rate (LHV)	BTU/kWh	9,276	9,276	9,830	11,628	9,055	9,055	9,594	11,103	8,980	8,980	9,578	11,068	9,820
Gross CTG Heat Rate (HHV)	BTU/kWh	10,282	10,282	10,897	12,890	10,037	10,037	10,635	12,308	9,955	9,955	10,618	12,269	10,547
CTG Heat Input (LHV) each	MBtu/hr	1,741	1,741	1,384	1,091	1,835	1,835	1,458	1,125	1,914	1,914	1,531	1,179	1,999
CTG Heat Input (HHV) each	MBtu/hr	1,930	1,930	1,534	1,210	2,034	2,034	1,616	1,247	2,122	2,122	1,697	1,307	2,147
Total Plant Auxiliary Power	kW	7,135	6,713	5,951	5,328	7,324	6,897	6,116	5,425	7,439	7,008	6,231	5,540	7,169
Auxiliary Power & Losses as Percent of Gross	%	2.34%	2.32%	2.64%	3.20%	2.25%	2.23%	2.53%	3.07%	2.21%	2.19%	2.49%	3.02%	2.35%
NET PLANT PERFORMANCE														
Net Plant Output	kW	297,265	282,460	219,716	161,168	317,622	302,093	235,738	171,363	328,753	313,131	244,485	178,074	297,838
Net Plant Heat Rate (LHV)	BTU/kWh	6,255	6,177	6,312	6,786	6,178	6,088	6,199	6,580	6,215	6,127	6,277	6,639	6,713
Net Plant Heat Rate (HHV)	BTU/kWh	6,917	6,832	6,980	7,505	6,832	6,732	6,856	7,276	6,873	6,776	6,942	7,342	7,210
Net Plant Efficiency (LHV)	%	54.58%	55.27%	54.09%	50.31%	55.26%	56.08%	55.07%	51.89%	54.93%	55.73%	54.39%	51.43%	50.86%
Net Plant Efficiency (HHV)	%	49.36%	49.98%	48.91%	45.49%	49.97%	50.71%	49.80%	46.92%	49.67%	50.39%	49.18%	46.50%	47.35%
STACK EMISSIONS														
NOx	ppmvd@15% O2													
	lb/MBtu (HHV)													
	lb/hr													
CO	ppmvd@15% O2													
	lb/MBtu (HHV)													
	lb/hr													
VOC	ppmvd@15% O2													
	lb/MBtu (HHV)													
	lb/hr													
PM 2.5/10 - Front Half Only	lb/hr													
PM 2.5/10 - Front Half and Back Half	lb/hr													
CO2	lb/hr													
NH3 Slip	lb/hr													

JEA Study
B&V Project Number 198807
Jenbacher 920, RICE 5x0
Preliminary Performance Summary
July 25, 2018 - Rev 0

Case #	Units	1	2	3	4	5	6	7	8	9
Revision #		Rev 0	Rev 0	Rev 0	Rev 0	Rev 0	Rev 0	Rev 0	Rev 0	Rev 0
Description		98 deg F 100% Engine Load	98 deg F 75% Engine Load	98 deg F 40% (MECL) Engine Load	69 deg F 100% Engine Load	69 deg F 75% Engine Load	69 deg F 40% (MECL) Engine Load	24 deg F 100% Engine Load	24 deg F 75% Engine Load	24 deg F 40% (MECL) Engine Load
Configuration	-	5x0	5x0	5x0	5x0	5x0	5x0	5x0	5x0	5x0
Heat Rejection System		-	-	-	-	-	-	-	-	-
Ambient Drybulb Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	70.0	70.0	70.0	60.0	60.0	60.0
Engine Inlet Air Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
Engine Model	-	Jenbacher 920	Jenbacher 920	Jenbacher 920	Jenbacher 920	Jenbacher 920	Jenbacher 920	Jenbacher 920	Jenbacher 920	Jenbacher 920
Engine Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Engine Load Level		1	1	40% (MECL)	1	1	40% (MECL)	1	1	40% (MECL)
NEW & CLEAN PERFORMANCE										
Gross STG Output		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gross Engine Output (each)	kW	9,339	7,004	3,736	9,339	7,004	3,736	9,339	7,004	3,736
Gross Engine Heat Rate (LHV)	BTU/kWh	6,923	7,110	7,849	6,918	7,105	7,843	6,918	7,105	7,843
Gross Engine Heat Rate (HHV)	BTU/kWh	7,682	7,889	8,709	7,677	7,884	8,703	7,677	7,884	8,703
Engine Heat Input (LHV) each	MBtu/hr	65	50	29	65	50	29	65	50	29
Engine Heat Input (HHV) each	MBtu/hr	72	55	33	72	55	33	72	55	33
Total Plant Auxiliary Power	kW	996	932	842	996	932	842	996	932	842
Auxiliary Power & Losses as Percent of Gross	%	2.13%	2.66%	4.51%	2.13%	2.66%	4.51%	2.13%	2.66%	4.51%
NET PLANT PERFORMANCE										
Net Plant Output	kW	45,699	34,089	17,836	45,699	34,089	17,836	45,699	34,089	17,836
Net Plant Heat Rate (LHV)	BTU/kWh	7,074	7,304	8,219	7,069	7,299	8,213	7,069	7,299	8,213
Net Plant Heat Rate (HHV)	BTU/kWh	7,849	8,105	9,120	7,844	8,099	9,113	7,844	8,099	9,113
Net Plant Efficiency (LHV)	%	48.24%	46.72%	41.52%	48.27%	46.75%	41.55%	48.27%	46.75%	41.55%
Net Plant Efficiency (HHV)	%	43.47%	42.10%	37.41%	43.50%	42.13%	37.44%	43.50%	42.13%	37.44%
STACK EMISSIONS										
NOx	ppmvd@15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/MBtu (HHV)	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179	0.0179
	lb/hr	1.3	1	0.6	1.3	1	0.6	1.3	1	0.6
CO	ppmvd@15% O2	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
	lb/MBtu (HHV)	0.0305	0.0305	0.0305	0.0306	0.0306	0.0306	0.0306	0.0306	0.0306
	lb/hr	2.2	1.7	1	2.2	1.7	1	2.2	1.7	1
VOC	ppmvd@15% O2	8.0	8.4	8.8	8.0	8.4	8.8	8.0	8.4	8.8
	lb/MBtu (HHV)	0.0100	0.0105	0.0110	0.0100	0.0105	0.0110	0.0100	0.0105	0.0110
	lb/hr	0.7	0.6	0.4	0.7	0.6	0.4	0.7	0.6	0.4
PM 2.5/10 - Front Half Only	lb/hr	0.4	0.3	0.2	0.4	0.3	0.2	0.4	0.3	0.2
PM 2.5/10 - Front Half and Back Half	lb/hr	0.7	0.7	0.4	0.7	0.7	0.4	0.7	0.7	0.4
CO2	lb/hr	8,231	6,338	3,731	8,231	6,338	3,731	8,231	6,338	3,731
NH3 Slip	lb/hr	1.0	0.7	0.4	1.0	0.7	0.4	1.0	0.7	0.4

JEA Study
B&V Project Number 198807
Wartsila 18V50SG, RICE 5x0
Preliminary Performance Summary
July 25, 2018 - Rev 0

Case #	Units	1	2	3	4	5	6	7	8	9
Revision #		Rev 0	Rev 0	Rev 0	Rev 0	Rev 0	Rev 0	Rev 0	Rev 0	Rev 0
Description		98 deg F 100% Engine Load	98 deg F 75% Engine Load	98 deg F 30% (MECL) Engine Load	69 deg F 100% Engine Load	69 deg F 75% Engine Load	69 deg F 30% (MECL) Engine Load	24 deg F 100% Engine Load	24 deg F 75% Engine Load	24 deg F 30% (MECL) Engine Load
Configuration	-	5x0	5x0	5x0	5x0	5x0	5x0	5x0	5x0	5x0
Heat Rejection System		-	-	-	-	-	-	-	-	-
Ambient Drybulb Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0
Ambient Relative Humidity	%	60.0	60.0	60.0	70.0	70.0	70.0	60.0	60.0	60.0
Engine Inlet Air Temperature	F	98.0	98.0	98.0	69.0	69.0	69.0	24.0	24.0	24.0
Barometric Pressure	psia	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66	14.66
Engine Model	-	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG
Engine Fuel	-	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Engine Load Level		1	1	30% (MECL)	1	1	30% (MECL)	1	1	30% (MECL)
NEW & CLEAN PERFORMANCE										
Gross STG Output		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Gross Engine Output (each)	kW	18,817	14,113	5,645	18,817	14,113	5,645	18,817	14,113	5,645
Gross Engine Heat Rate (LHV)	BTU/kWh	7,534	7,854	9,200	7,411	7,749	9,138	7,377	7,718	9,096
Gross Engine Heat Rate (HHV)	BTU/kWh	8,360	8,715	10,209	8,223	8,598	10,140	8,186	8,564	10,093
Engine Heat Input (LHV) each	MBtu/hr	142	111	52	139	109	52	139	109	51
Engine Heat Input (HHV) each	MBtu/hr	157	123	58	155	121	57	154	121	57
Total Plant Auxiliary Power	kW	1,983	1,853	1,620	1,983	1,853	1,620	1,983	1,853	1,620
Auxiliary Power & Losses as Percent of Gross	%	2.11%	2.63%	5.74%	2.11%	2.63%	5.74%	2.11%	2.63%	5.74%
NET PLANT PERFORMANCE										
Net Plant Output	kW	92,102	68,711	26,605	92,102	68,711	26,605	92,102	68,711	26,605
Net Plant Heat Rate (LHV)	BTU/kWh	7,696	8,066	9,761	7,570	7,958	9,695	7,536	7,926	9,650
Net Plant Heat Rate (HHV)	BTU/kWh	8,539	8,950	10,830	8,400	8,830	10,757	8,362	8,795	10,708
Net Plant Efficiency (LHV)	%	44.34%	42.30%	34.96%	45.07%	42.88%	35.20%	45.28%	43.05%	35.36%
Net Plant Efficiency (HHV)	%	39.96%	38.12%	31.51%	40.62%	38.64%	31.72%	40.81%	38.80%	31.87%
STACK EMISSIONS										
NOx	ppmvd@15% O2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
	lb/MBtu (HHV)	0.0162	0.0161	0.0161	0.0162	0.0161	0.0162	0.0162	0.0161	0.0162
	lb/hr	2.5	2	0.9	2.5	2	0.9	2.5	2	0.9
CO	ppmvd@15% O2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	lb/MBtu (HHV)	0.0328	0.0328	0.0327	0.0328	0.0328	0.0328	0.0328	0.0328	0.0328
	lb/hr	5.2	4	1.9	5.1	4	1.9	5	4	1.9
VOC	ppmvd@15% O2	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
	lb/MBtu (HHV)	0.0326	0.0325	0.0325	0.0325	0.0325	0.0326	0.0325	0.0325	0.0326
	lb/hr	5.1	4	1.9	5	3.9	1.9	5	3.9	1.9
PM 2.5/10 - Front Half Only	lb/hr	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
PM 2.5/10 - Front Half and Back Half	lb/hr	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
CO2	lb/hr	18,080	14,129	6,612	17,778	13,937	6,585	17,696	13,882	6,557
NH3 Slip	lb/hr	2.1	1.6	0.8	2.1	1.6	0.8	2.0	1.6	0.8

Battery Description		
Project Size (kW)	37500	
Storage Duration (Hrs)	1	
Building	0	
Number of Battery Containers	7	
Inverter size (kVA)	3000	
Inverter size (kW)	2760	
Number of Inverters/transformers	14	
Main transformer size	43421	

Battery Energy Storage cost model	**Extended $**	**% of total**
Batteries in racks	$9,937,500	55.6%
Inverter	$2,437,500	13.6%
Containerization	$1,400,000	7.8%
Shipping	$175,000	1.0%
Subtotal, Owner Furnished Equipment	$13,950,000	78.0%

Site & Labor Costs	**Extended $**	**% of project total**
SCADA / Site Controller	$250,000	1.4%
BUILDING	$0	
EPC balance of system costs		
BOS Main transformer, equipment only	$390,789	2.2%
BOS padmounts, equipment only	$504,000	2.8%
BOS Set, load, and terminate batteries	$95,625	0.5%
BOS Conductors and Raceway, matl & labor	$571,500	3.2%
BOS Foundations, matl & labor	$120,375	0.7%
BOS site development	$37,500	0.2%
Interconnect	$0	0.0%
Balance of System EPC direct costs	$1,969,789	11.0%

Balance of System		
CMCI	$492,447	2.8%
Engineering, Procurement, and PM	$455,000	2.5%
Balance of System EPC direct costs	$1,969,789	11.0%
EPC Margin	$157,583	0.9%
BOS EPC total	$3,074,820	17.2%
Battery Energy Storage System Subtotal	**$13,950,000**	78.0%
Balance of System EPC Subtotal	**$3,074,820**	17.2%
Project Total Cost (exluding Owner's costs, Contingency)	**$17,024,820**	95.2%
Project Contingency	**$851,241**	4.8%
PROJECT TOTAL (excl Owner's costs)	**$17,876,061**	100.0%

Cost	**Batteries Only**	**System[1]**
$/kW	$372	$477
$/kWhr	$372	$477

Note 1 - Owner's costs not included

Battery Description		
Project Size (kW)	25000	
Storage Duration (Hrs)	1	
Building	0	
Number of Battery Containers	5	
Inverter size (kVA)	3000	
Inverter size (kW)	2760	
Number of Inverters/transformers	10	
Main transformer size	28947	

Battery Energy Storage cost model	**Extended $**	**% of total**
Batteries in racks	$6,625,000	52.6%
Inverter	$1,625,000	12.9%
Containerization	$1,250,000	9.9%
Shipping	$150,000	1.2%
Subtotal, Owner Furnished Equipment	$9,650,000	76.6%

Site & Labor Costs	**Extended $**	**% of project total**
SCADA / Site Controller	$250,000	2.0%
BUILDING	$0	
EPC balance of system costs		
BOS Main transformer, equipment only	$260,526	2.1%
BOS padmounts, equipment only	$360,000	2.9%
BOS Set, load, and terminate batteries	$63,750	0.5%
BOS Conductors and Raceway, matl & labor	$381,000	3.0%
BOS Foundations, matl & labor	$80,250	0.6%
BOS site development	$25,000	0.2%
Interconnect	$0	0.0%
Balance of System EPC direct costs	$1,420,526	11.3%

Balance of System		
CMCI	$355,132	2.8%
Engineering, Procurement, and PM	$455,000	3.6%
Balance of System EPC direct costs	$1,420,526	11.3%
EPC Margin	$113,642	0.9%
BOS EPC total	$2,344,300	18.6%
Battery Energy Storage System Subtotal	**$9,650,000**	76.6%
Balance of System EPC Subtotal	**$2,344,300**	18.6%
Project Total Cost (exluding Owner's costs, Contingency)	**$11,994,300**	95.2%
Project Contingency	**$599,715**	4.8%
PROJECT TOTAL (excl Owner's costs)	**$12,594,015**	100.0%

Cost	**Batteries Only**	**System[1]**
$/kW	$386	$504
$/kWhr	$386	$504

Battery Description		
Project Size (kW)	50000	
Storage Duration (Hrs)	4	
Building	0	
Number of Battery Containers	36	
Inverter size (kVA)	3000	
Inverter size (kW)	2760	
Number of Inverters/transformers	18	
Main transformer size	57895	

Battery Energy Storage cost model	**Extended $**	**% of total**
Batteries in racks	$53,000,000	76.2%
Inverter	$3,250,000	4.7%
Containerization	$6,300,000	9.1%
Shipping	$900,000	1.3%
Subtotal, Owner Furnished Equipment	$63,450,000	91.3%

Site & Labor Costs	**Extended $**	**% of project total**
SCADA / Site Controller	$250,000	0.4%
BUILDING	$0	
EPC balance of system costs		
BOS Main transformer, equipment only	$521,053	0.7%
BOS padmounts, equipment only	$648,000	0.9%
BOS Set, load, and terminate batteries	$510,000	0.7%
BOS Conductors and Raceway, matl & labor	$762,000	1.1%
BOS Foundations, matl & labor	$642,000	0.9%
BOS site development	$200,000	0.3%
Interconnect	$0	0.0%
Balance of System EPC direct costs	$3,533,053	5.1%

Balance of System		
CMCI	$883,263	1.3%
Engineering, Procurement, and PM	$520,000	0.7%
Balance of System EPC direct costs	$3,533,053	5.1%
EPC Margin	$282,644	0.4%
BOS EPC total	$5,218,960	7.5%

Battery Energy Storage System Subtotal	**$63,450,000**	91.3%
Balance of System EPC Subtotal	**$5,218,960**	7.5%
Project Total Cost (exluding Owner's costs, Contingency)	**$68,668,960**	98.8%
Project Contingency	**$851,241**	1.2%
PROJECT TOTAL (excl Owner's costs)	**$69,520,201**	100.0%

Cost	**Batteries Only**	**System[1]**
$/kW	$1,269	$1,390
$/kWhr	$317	$348

Note 1 - Owner's costs not included

Battery Description		
Project Size (kW)	75000	
Storage Duration (Hrs)	4	
Building	0	
Number of Battery Containers	27	
Inverter size (kVA)	3000	
Inverter size (kW)	2760	
Number of Inverters/transformers	27	
Main transformer size	86842	

Battery Energy Storage cost model	**Extended $**	**% of total**
Batteries in racks	$79,500,000	81.1%
Inverter	$4,875,000	5.0%
Containerization	$4,725,000	4.8%
Shipping	$675,000	0.7%
Subtotal, Owner Furnished Equipment	$89,775,000	91.6%

Site & Labor Costs	**Extended $**	**% of project total**
SCADA / Site Controller	$250,000	0.3%
BUILDING	$0	
EPC balance of system costs		
BOS Main transformer, equipment only	$781,579	0.8%
BOS padmounts, equipment only	$972,000	1.0%
BOS Set, load, and terminate batteries	$765,000	0.8%
BOS Conductors and Raceway, matl & labor	$1,143,000	1.2%
BOS Foundations, matl & labor	$963,000	1.0%
BOS site development	$300,000	0.3%
Interconnect	$0	0.0%
Balance of System EPC direct costs	$5,174,579	5.3%

Balance of System		
CMCI	$1,293,645	1.3%
Engineering, Procurement, and PM	$520,000	0.5%
Balance of System EPC direct costs	$5,174,579	5.3%
EPC Margin	$413,966	0.4%
BOS EPC total	$7,402,190	7.6%

Battery Energy Storage System Subtotal	**$89,775,000**	91.6%
Balance of System EPC Subtotal	**$7,402,190**	7.6%
Project Total Cost (exluding Owner's costs, Contingency)	**$97,177,190**	99.1%
Project Contingency	**$851,241**	0.9%
PROJECT TOTAL (excl Owner's costs)	**$98,028,431**	100.0%

Cost	**Batteries Only**	**System**[1]
$/kW	$1,197	$1,307
$/kWhr	$299	$327

Note 1 - Owner's costs not included

Battery		Fixed O&M					Variable O&M
Power	Energy	PCS O&M $/kW	BESS O&M $/kWhr	PCS annual $	BESS annual $	Unplanned annual $	HVAC
25000	25000	$0.43	$1.60	$10,750	$40,000	$10,150	$17,345
37500	37500	$0.43	$1.60	$16,125	$60,000	$15,225	$26,017
50000	200000	$0.43	$1.60	$21,500	$320,000	$68,300	$14,171
75000	300000	$0.43	$1.60	$32,250	$480,000	$102,450	$21,256

Battery		Total O&M W/O HVAC			Total O&M With HVAC		
Power	Energy	Total O&M *excluding* HVAC and charging	$/kW-year	$/kwhr-year	Total O&M *including* HVAC (excluding charging)	$/kW-year	$/kwhr-year
25000	25000	$60,900	$2.44	$2.44	$78,245	$3.13	$3.13
37500	37500	$91,350	$2.44	$2.44	$117,367	$3.13	$3.13
50000	200000	$409,800	$8.20	$2.05	$423,971	$8.48	$2.12
75000	300000	$614,700	$8.20	$2.05	$635,956	$8.48	$2.12

Note: HVAC operating costs, assumptions:

For 4 hour system HVAC, assume 1% of energy flow is lost into heat and HVAC system has a 3:1 efficiency. Assume aux power wholesale rate is $0.025 / kWhr

For 1 hour system, assume heat rejection at 1 hour charge/discharge rate is 4% of energy flowing in/out of battery and an effective capacity factor of 12 percent (25% capacity factor during daytime hours).

Assume unplanned maintenance is equal to 20% of planned maintenance.

Charging costs are excluded from O&M costs

Capacity refreshes are excluded from O&M. For 4 hour system assume refreshes at 6 year intervals equal to 6 % of battery initial capacity. Battery prices are projected to decline at 6-8% per year.