Kaua`i Island Utility Cooperative

GenX Option Screening Study

FINAL REPORT
B&V Project Number 143150
B&V File Number 40.0000

November 2008

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1.0 Executive Summary

The Kaua`i Island Utility Cooperative ("KIUC") recently identified the need to look into a near-term addition of generation capacity. This need was based on two primary factors. First, KIUC recently sought, and received, clarification of its Adequacy of Supply requirement, which essentially comprises two criteria; (1)KIUC must be able to meet its morning peak with its largest unit out for any reason and its third largest unit out on scheduled maintenance; and (2) KIUC must be able to meet its evening peak with its largest unit out for any reason. Second, in recognition of the reliability issues stemming from the lack of adequate inertia on its system, KIUC needs to add a unit or units of significant inertia to its system. This condition became apparent when the Lihue Plantation, once a major contributor to KIUC's capacity and energy needs, went out of business thus resulting in the loss of generation provided by its high inertia steam turbine generator.

The need for an immediate solution to the above-described issues requires that KIUC develop a strategy for integrating short-term requirements with longer-term resource considerations within its integrated resource plan (IRP). Only the options that satisfy near-term needs will be considered in the near-term solution. Once the near-term solution has been determined, it will become the "anchor" resource in the IRP multiple expansion plans, which will then integrate other longer-term options in comprehensive approaches that meet IRP objectives in various ways.

The near-term selection of a capacity generation unit referred to herein as "GenX" plays an important role in the IRP process and is the basis for the comprehensive study that is the subject of this report. As described above, the outcome of study will serve as the justification for the "anchor" unit in each of the IRP scenarios that are to be developed and is consistent with the requirements of the Hawaii Public Utilities Commission's IRP Framework. Additional resources, including renewable energy options will provide the balance of generation required to allow each viable plan to meet the State's RPS requirements and other IRP objectives.

As part of the short-term IRP process, Black & Veatch has been commissioned to conduct a Technology Screening Study to assist KIUC with the evaluation and selection of the GenX unit to be installed at the existing Lihue Energy Services Center ("LESC") on the Island of Kaua`i.

The objective of this Technology Screening Study is to provide KIUC with preliminary thermal performance and cost information for seven options to be constructed at the existing LESC site. The results of the Technology Screening Study will enable KIUC to proceed with further stages of study and project development for a single option for the GenX unit that will best fit the needs and objectives of the cooperative. The technology options considered in this GenX study are shown in Table 1-1.

Table 1-1
GenX Options Considered

Option Number	Technology	OEM	Configuration
1	SCCT	GE	LM2500PE STIG 30
2	CCCT	Solar	1 x 1 Solar Titan 130
3	CCCT	Solar	2 x 1 Solar Titan 130
4	CCCT	GE	1 x 1 LM2500PE
5	CCCT	GE	1 x 1 LM2000
6	CCCT	GE	2 x 1 LM2000
7	SCDE	Wärtsilä	18V46 x 2
8	CCDE	Wärtsilä	2 x 1 18V46

This study includes estimates of thermal performance, capital cost, operations and maintenance costs for each of the technology options. These inputs are used in levelized busbar cost analysis which compares the costs of energy for each technology. The report also addresses grid stability characteristics for each option.

1.1 Thermal Performance Estimates

Preliminary performance and emission estimates were generated for all options considered in this study based on the LESC site conditions. These are summarized in Table 4-2. Since the GenX options are expected to encounter varying daily and seasonal demands, performance estimates are provided at full load, 75 percent load, and 50 percent load. Evaporative cooling was assumed for all full load cases to increase output at times of high power demand.

1.2 Grid Stability

As a result of sudden load changes, loss of generator-to-grid synchronization can cause unit trip, resulting in grid instability. To evaluate the grid stability effects resulting from the addition of each GenX option, the spinning energy storage per unit of capacity was estimated for each option based on values provided by the OEMs. The calculations considered representative combustion turbine (CT) and CT generator, and reciprocating engine and reciprocating engine generator inertia constants.

For comparison purposes, the calculations did not consider the spinning energy storage per unit output for the steam turbine generators (STG) in the combined cycle configuration cases. The addition of an STG would provide more spinning energy momentum and positively contribute to any synchronization instabilities.

The representative stored energy per unit of capacity results are presented in Table 5-1 and are subject to original equipment manufacturer (OEM) validation. The results show that Options 2 and 3 (1x1 and 2x1 Solar Titan 130) offers the largest spinning energy and would provide better grid stability compared to the other GenX options.

1.3 Capital Cost Estimates

Preliminary screening level overnight 2008 capital cost estimates for the GenX options were developed. All estimates are presented on an EPC basis exclusive of Owner's costs. Owner's cost should be considered by the project developer/owner to determine the total capital requirement for the project. Potential Owner's costs are listed in Table 6-1.

The following subsections provide the capital cost assumptions used to develop the estimates. These assumptions were broken down into the major capital cost estimate components consisting of general assumptions, direct and indirect cost assumptions.

The preliminary capital cost estimates are summarized in **Error! Reference source not found.**. The estimates presented are reasonable for today's market, but as demonstrated in the last few years, the market is dynamic and unpredictable. Power plant costs are subject to continued volatility in the future, and the estimates in this report should be viewed with this in mind.

1.4 O&M Cost Estimates

Preliminary screening level estimates of operations and maintenance (O&M) expenses, including fixed and non-fuel variable annual expenses were developed for each of the eight options. The estimates are expressed in second quarter 2008 dollars.

All O&M estimates were generated on a consistent basis. Assumptions used to develop the performance estimates were also used to develop the O&M estimates. Operating assumptions specific to the development of the O&M estimates are summarized in **Error! Reference source not found.**.

1.5 Busbar Cost Analysis

Levelized busbar cost analyses for each of the options for were performed using the following sets of data:

- Estimated EPC capital costs, shown in **Error! Reference source not found.**.
- O&M cost estimates, shown in **Error! Reference source not found.**.
- Performance estimates, shown in **Error! Reference source not found.**.
- Economic assumptions, shown in Table 7-1.
- Fuel Oil Forecasts in Tables A-1 to A-3 in Appendix A.

The results of the busbar cost analysis, shown in Table 7-2 are based on an April 2011 unit commercial operation date. The preliminary results indicate Option 4, the 1x1 GE LM2500 PE, is the low cost technology choice among the configurations studied. This is due largely to the lower capital cost and plant heat rate.

The results also indicate that the CT options will have an approximate 2.5 percent lower cost of production when firing Naphtha compared to No. 2 Fuel oil.

1.6 Options Screening

Three options are notable among all those reviewed: the 1x1 LM2500, the 1x1 Solar Titan and the 2x1 Solar Titan.

- The 1x1 LM2500 PE option has the lowest busbar cost and lowest heat rate among the three.
- The 1x1 and 2x1 Solar Titan options have considerably better grid stability characteristics than the LM 2500, which may outweigh the cost and performance benefits of the LM 2500.

Additional IRP benefits may be discovered that are beyond the busbar cost analysis that was performed for this study. These could include infrastructure requirements, such as availability of transmission or water, or compatibility with forecasted load requirements.

2.0 Introduction

2.1 Background

As required by the HPUC, KIUC conducts an IRP that evaluates various technologies to determine which will meet expected near and long term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost.

As part of the short-term IRP process, Black & Veatch has been commissioned to conduct a Technology Screening Study to assist KIUC in the selection of the next unit of capacity generation (GenX) at the existing LESC on the Island of Kaua`i.

The existing LESC site currently comprises a simple cycle model LM2500 Steam Injected Gas Turbine (STIG) unit manufactured by General Electric (GE). The LESC site also contains all associated equipment to support the simple cycle unit. Figure 2-1 shows an aerial view of the current LESC site layout.

This study provides preliminary screening level performance, capital costs, operations and maintenance (O&M) costs, and levelized busbar costs of energy for a mix of seven fossil fuel unit options. Table 2-1 provides a brief overview of the options considered.

Figure 2-1. Aerial View of current LESC Site

Table 2-1
GenX Options Considered

Option Number	Technology	OEM	Configuration
1	SCCT	GE	LM2500PE STIG 30
2	CCCT	Solar	1 x 1 Solar Titan 130
3	CCCT	Solar	2 x 1 Solar Titan 130
4	CCCT	GE	1 x 1 LM2500PE
5	CCCT	GE	1 x 1 LM2000
6	CCCT	GE	2 x 1 LM2000
7	SCDE	Wärtsilä	18V46 x 2
8	CCDE	Wärtsilä	2 x 1 18V46

2.2 Objective

The objective of this Technology Screening Study is to provide KIUC with preliminary thermal performance and cost information for seven options to be constructed at the existing LESC site. The results of the Technology Screening Study will enable KIUC to proceed with further stages of study and project development for a single option for the GenX unit that will best fit the needs and objectives of the cooperative.

The options evaluated in this study were evaluated on the following criteria set forth by KIUC:

- Must be capable of being located at the existing LESC site.
- Must have proven operational history and technology.
- Size and Firm Capacity: The options considered must meet adequacy of supply needs and be capable of dispatching base loaded power to reduce system operating cost. The options considered in this study range in size of 15 MW to 40 MW and are assumed to operate at a 90 percent capacity factor.
- Grid Stability: The options considered must take into account the ability of the system to maintain synchronization with the grid; would at worst do no harm and at best improve stability.
- Cycle Capability: The options considered should have the capability to cycle in order to adjust power output to cycling power demands.

- Multi-Fuel Capability: The options considered should have the capability of burning boidiesel, No. 2 fuel oil, and Naphtha (except for reciprocating Options 7 and 8) to provide KIUC with fuel sourcing flexibility.
- Efficiency: Must comply with the Hawai'i Clean Energy Initiative and global energy use and efficiencies

3.0 GenX Options Considered

This section provides a brief combustion technology description followed by descriptions for each of the GenX options considered.

3.1 Combustion Turbine Technology Description

Combustion turbine generators (CTGs) are highly sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A CTG generates power by compressing ambient air to approximately 12 to 30 atmospheres, heats the pressurized air to 2,000° F or more by burning fuel oil, naphtha, or natural gas, and then expands those hot gases through a turbine. The turbine drives both the air compressor and an electric generator.

CTGs are mass flow devices, and thus their performance changes with ambient conditions. Generally speaking, as temperatures rise, CTG efficiency and output decrease due to the lower density of the air. To lessen the impact of this negative characteristic, most conventional power plants now include inlet air cooling systems to boost plant performance at higher ambient temperatures. In addition to ambient condition sensitivity to full load performance, CTG emission rates are typically higher at part load. This limitation has an effect on the turn down of the machine due to emission limits. It is estimated that the CTG plant output can be reduced to approximately 50 percent load and maintain emission levels within required limits.

A typical CTG would convert 30 to 35 percent of the fuel energy to electric power. A substantial portion of the fuel energy is wasted in the form of hot (900° F to 1,100° F) gases exiting the turbine exhaust. When the CTG is used to generate power and no energy is captured from the hot exhaust gasses, the power cycle is referred to as a simple cycle combustion turbine (SCCT). Alternatively, when the hot gases of combustion are captured by a heat recovery steam generator (HRSG) and passed through a steam turbine, the power cycle is referred to as a combined cycle combustion turbine (CCCT).

Advantages to SCCT projects are their low capital cost, short design and installation schedules, and wide availability.

The major components for a CCCT unit include the CTG(s) and steam turbine generator (STG), HRSG, heat rejection, and air quality control systems (AQCS).

CCCT have several advantages over SCCT. These include lower NO_x and CO emissions, greater efficiency, and potentially greater operating flexibility if duct firing is used.

Disadvantages of a CCCT plants, relative to the SCCT plants, include a reduction in plant reliability, increased capital cost, and increase in the overall staffing and maintenance requirements because of the added plant complexity.

The following subsections provide a brief technology description of each of the GenX options considered.

3.1.1 Option 1 – Simple Cycle GE LM2500PE STIG 30

The LM2500 STIG 30 CTG is derived from the GE LM2500 family of machines which have more than 2,000 installations worldwide and 40 million operating hours. The LM2500 is a 2-shaft machine consisting of a 16-stage axial compressor, an annular combustor, and a 6-stage axial flow turbine.

The hot gases of combustion pass through a once-through steam generator (OTSG) which produces steam that is injected into the high pressure section of the CT via the combustor fuel nozzles and compressor discharge plenum. Steam injection decreases NO_x emissions and increases the mass flow through the CT which consequently increases the power output up to 25 percent. The LM2500 STIG allows a variable steam injection rate from 50 percent load to full load.

To further decrease NO_x emissions, selective catalytic reduction (SCR) is included for Option 1. The SCR system injects an ammonia/CO_2 gas, derived from urea, into the ammonia injection grid located in the OTSG to remove NO_x.

3.1.2 Option 2 – Combined Cycle 1 x 1 Solar Titan 130

Solar Turbines, a subsidiary of Caterpillar Inc., began manufacturing the Solar Titan 130 CTG in 1997. The Solar Titan 130 CTG consists of a 14-stage variable geometry axial compressor, an annular combustor, and a 3-stage axial flow turbine.

Option 2 considers a combined cycle configuration with one CTG and HRSG train and a single steam turbine. Heat from the exhaust gases of the Solar Titan 130 is captured in its associated HRSG. Steam produced from the HRSG is transmitted to a nominally rated 4.5 MW steam turbine.

NOx reduction is achieved by water injection into the CT and by a urea-based SCR system located in the HRSG.

3.1.3 Option 3 – Combined Cycle 2 x 1 Solar Titan 130

Option 3 considers a combined cycle configuration with two CTG and HRSG trains and a single steam turbine. Heat from the exhaust gases of each Solar Titan 130 is captured in their respective HRSG. Steam produced from the two HRSGs is transmitted to a nominally rated 9 MW steam turbine.

NO_x reduction is achieved by water injection into the CT and by a urea-based SCR system located in the HRSG.

3.1.4 Option 4 – Combined Cycle 1 x 1 GE LM2500PE

Option 4 includes an HRSG and STG with a GE LM2500PE CTG. The STG for the GE LM2500PE CCCT unit is nominally rated at 9 MW.

NO_x reduction is achieved by water injection into the CT and by a urea-based SCR system located in the HRSG.

3.1.5 Option 5 – Combined Cycle 1 x 1 GE LM2000

With approximately 600 units in service and over 24 million operating hours, the LM2000 CTG has proven commercial maturity and is essentially a derated LM2500 CT.

Option 5 comprises an LM2000 CTG, a HRSG, and a nominally rated 5 MW steam turbine. NO_x reduction is achieved by water injection into the CT and by a urea-based SCR system located in the HRSG.

3.1.6 Option 6 – Combined Cycle 2 x 1 GE LM2000

The CCCT configuration for Option 6 consists of two LM2000 CTGs, two HRSGs, and a nominally rated 10 MW steam turbine. NO_x reduction is achieved by water injection into the CT and by a urea-based SCR system located in the HRSG.

3.1.7 Option 7 – Simple Cycle Wärtsilä 2 x 18V46

Option 7 consists of two Wartsila 18V46 diesel generators. NO_x reduction is achieved by a urea-based SCR system located in the ductwork before the stack.

3.1.8 Option 8 – Combined Cycle 2 x 1 Wärtsilä 18V46

Option 8 consists of two Wartsila 18V46 diesel generators, two HRSGs, and a nominally rated 3 MW steam turbine. NO_x reduction is achieved by a urea-based SCR system located in the HRSG.

4.0 Performance and Emissions Estimates

This section presents preliminary estimates of performance and emissions for each of the GenX options. The preliminary performance estimates were generated using Thermoflow and GE's Application for Packaged Power Solutions (APPS) performance models, and manufacturer data and are based on the meteorological conditions shown below.

4.1 Meteorological Conditions

For the basis of the performance estimates, plant site conditions consisting of the site elevation and ambient conditions were used for the existing site. Performance estimates were generated for average day ambient conditions which were referenced from the International Station Meteorological Climate Summary. Table 4-1 summarizes the assumed plant site conditions.

Table 4-1
Assumed LESC Plant Site Conditions

Site Elevation, ft	270
Ambient Case	Average Day
Ambient Dry Bulb Temperature, ° F	76
Ambient Wet Bulb Temperature, ° F	69
Relative Humidity, percent	73

Note:
Ambient conditions were referenced from the International Station Meteorological Climate Summary.

4.2 Preliminary Thermal Performance and Emission Estimates

Preliminary performance and emission estimates were generated for all options considered in this study based on the LESC site conditions shown in Table 4-1.

Since the GenX options are expected to encounter varying daily and seasonal demands, performance estimates are provided at full load, 75 percent load, and 50 percent load. Evaporative cooling was assumed for all full load cases to increase output at times of high power demand. Because of the limited water supply available at the LESC site, air-cooled condensing was assumed as the method of heat rejection for all combined cycle options.

Table 4-2 and Table 4-3 show the performance and emission estimates based on all GenX options firing ultra-low sulfur fuel oil. The values shown are reflective of new and clean units at full load and do not include the effects of degradation.

Table 4-2

Preliminary GenX Performance Estimates

Option	Plant Load Level	Gross Plant Output, MW	CTG/DE Gross Output, MW	STG Gross Output, MW	Auxiliary Load, MW	Net Plant Output, MW	Net Plant Heat Rate (HHV), Btu/kWh	Net Plant Heat Rate (LHV), Btu/kWh	Heat Input (HHV), MBtu/h	Water Consumption, gpm			
										Evaporative Cooling	Water Injection	Steam Cycle Makeup	Total Water Consumption
Option 1	Base	24.56	24.56	n/a	0.30	24.26	9,730	9,130	236	1.36	n/a	59.91	61.27
SCCT	75%	18.47	18.47	n/a	0.24	18.23	10,010	9,400	182	0	n/a	45.63	45.63
GE LM2500PE STIG 30	50%	12.26	12.26	n/a	0.16	12.10	11,110	10,430	134	0	n/a	36.39	36.39
Option 2	Base	17.68	12.82	4.86	0.31	17.37	8,610	8,090	150	0.95	15.19	0.07	16.22
CCCT	75%	13.05	9.37	3.69	0.29	12.77	9,670	9,080	123	0	12.21	0.06	12.27
1 x 1 Solar Titan 130	50%	8.90	6.24	2.65	0.26	8.64	11,480	10,780	99	0	9.58	0.05	9.62
Option 3	Base	36.29	25.64	10.64	0.79	35.50	8,420	7,910	299	1.90	30.39	0.14	32.43
CCCT	75%	26.85	18.73	8.12	0.67	26.18	9,430	8,850	247	0	24.42	0.11	24.53
2 x 1 Solar Titan 130	50% (2x1) [7]	18.38	12.49	5.89	0.57	17.81	11,130	10,450	198	0	19.16	0.09	19.25
	50% (1x1) [8]	18.09	12.82	5.27	0.48	17.61	8,490	7,970	150	0	15.15	0.07	15.22
Option 4	Base	34.65	24.47	10.18	0.74	33.91	7,760	7,290	263	1.36	27.36	0.18	28.9
CCCT	75%	25.60	18.29	7.31	0.63	24.97	8,010	7,520	200	0	17.27	0.14	17.41
1 x 1 GE LM2500PE	50%	17.73	12.20	5.53	0.53	17.19	8,590	8,070	148	0	10.72	0.11	10.83
Option 5	Base	19.98	14.52	5.46	0.44	19.54	8,500	7,990	166	1.14	12.56	0.03	13.73
CCCT	75%	15.12	10.53	4.59	0.38	14.73	8,980	8,440	132	0	9.01	0.02	9.03
1 x 1 GE LM2000	50%	10.78	7.03	3.75	0.33	10.45	9,840	9,240	103	0	5.95	0.02	5.97
Option 6	Base	40.96	29.04	11.92	0.88	40.07	8,290	7,790	332	2.28	25.12	0.13	27.53
CCCT	75%	31.09	21.06	10.03	0.76	30.33	8,730	8,200	265	0	18.02	0.11	18.13
2 x 1 GE LM2000	50% (2x1) [7]	22.30	14.05	8.24	0.66	21.64	9,500	8,920	206	0	11.89	0.09	11.98
	50% (1x1) [8]	20.59	14.52	6.07	0.60	19.99	8,320	7,810	166	0	12.63	0.07	12.70
Option 7	Base	34.15	34.15	n/a	0.56	33.59	8,260	7,760	277	n/a	n/a	n/a	n/a
SCDE	75%	25.61	25.61	n/a	0.50	25.12	8,330	7,820	209	n/a	n/a	n/a	n/a
2 x Wärtsilä 18V46	50%	17.02	17.02	n/a	0.43	16.59	8,730	8,200	145	n/a	n/a	n/a	n/a
Option 8	Base	37.13	34.15	2.98	0.87	36.26	7,652	7,190	277	n/a	n/a	0.01	0.01
CCDE	75%	27.93	25.61	2.32	0.77	27.16	7,703	7,230	209	n/a	n/a	0.01	0.01
2 x 1 Wärtsilä 18V46	50% (2x1) [7]	18.98	17.02	1.96	0.67	18.31	7,908	7,430	145	n/a	n/a	0.01	0.01
	50% (1x1) [8]	18.66	17.08	1.58	0.33	18.33	7,570	7,110	139	n/a	n/a	0.01	0.01

Notes:

1. Performance values are preliminary and do not include any margins. Guarantees therefore do not apply.
2. Values are based on average day ambient conditions as shown in Table 4-1.
3. Ultra-low sulfur fuel oil was assumed as the fuel with a sulfur weight content of 0.015%
4. GE LM2500PE STIG 30, GE LM2500PE, and GE LM2000 performance based on standard combustors.
5. Heat rejection for all combined cycle cases was achieved by an air-cooled condenser.
6. The GE LM2500PE STIG 30 can accept a maximum steam injection of 30,000 lb/hr (59.91 gpm) which has been assumed for maximum power output and NO_x control at the base load case. The OTSG has been modeled solely for supplying steam to the CTG for STIG purposes.
7. 50 percent load based on both CTs operating at 50 percent load.
8. 50 percent load based on a single CT operating at 100 percent load with the other CT shut down essentially operating as a 1x1 combined cycle.

Table 4-3
Preliminary GenX Emissions Estimates

Option	Flue Gas Flow, acfm	NO_x		SO_2		CO		VOC		Ammonia Slip		PM_{10}
		ppm	$\frac{lb}{hr}$	*ppm*	$\frac{lb}{hr}$	*ppm*	$\frac{lb}{hr}$	*ppm*	$\frac{lb}{hr}$	*ppm*	$\frac{lb}{hr}$	$\frac{lb}{hr}$
Option 1 SCCT GE LM2500 STIG 30	357,610	15	13.9	2.8	3.6	194	109	4.0	1.3	10	3.4	10.5
Option 2 CCCT 1 x 1 Solar Titan 130	225,800	15	8.8	2.8	2.3	50	18	2.5	0.5	10	2.2	8.5
Option 3 CCCT 2 x 1 Solar Titan 130	451,590	15	17.6	2.8	4.6	50	36	2.5	1.0	10	4.4	17.0
Option 4 CCCT 1 x 1 GE LM2500	359,180	15	15.5	2.8	4.0	14	9	0.4	0.1	10	3.8	10.5
Option 5 CCCT 1 x 1 GE LM2000	262,290	15	9.8	2.8	2.5	46	18	0.8	0.2	10	2.4	10.5
Option 6 CCCT 2 x 1 GE LM2000	524,570	15	19.6	2.8	5.0	46	36	0.8	0.4	10	4.8	21.0
Option 7 SCDE 2 x Wärtsilä 18V46	493,550	290	315	2.8	4.2	100	66	150 [8]	[8]	10	4.0	17.6
Option 8 CCDE 2 x 1 Wärtsilä 18V46	239,090	290	315	2.8	4.2	100	66	150 [8]	[8]	10	4.0	17.6

Notes:

1. Emissions provided are preliminary and do not include any margins. Guarantees therefore do not apply.
2. ppm is pounds per million dry volume at 15 percent O_2.
3. All values provided are based on 100 percent load.
4. Values represent the total plant emissions.
5. The flue gas flow refers to the CTG(s) exhaust flow.
6. Ultra-low sulfur fuel oil was used with a sulfur weight content of 0.015 percent for emissions.
7. GE LM2500PE STIG 30, GE LM2500PE, and GE LM2000 performance based on standard combustors. Water injection was used in the GE LM2500PE and GE LM2000 for NO_x control to 42 ppm. While on the LM2500PE STIG 30, steam injection was used to control NO_x to 42 ppm. For Solar Titan 130 water injection was used to control to 80 ppm.
8. The value of VOC for Wartsila 18V46 is at 150ppmv@15%O_2 (Wet) provided by the OEM. The VOC lb/h value will be provided by the OEM.
9. Emissions data shown includes an SCR where NO_x is controlled to 15ppmvd @ 15 percent O_2 and no CO catalyst has been used.
10. Estimated NO_x emissions on pounds per hour basis assumes NO_x as N_2.
11. The GE LM2500PE STIG 30 can accept a maximum steam injection of 30,000 lb/hr which has been assumed for maximum power output and NO_x control at the base load case. The OTSG has been modeled solely for supplying steam to the CTG for STIG purposes.
12. The SO_2 emissions value does not include reduction of SO_2 in the CTG and SCR.
13. PM_{10} emissions shown are both front and back half catch.

5.0 Grid Stability and Unit Flexibility Considerations

This section of the report assesses the grid stability characteristics of the GenX options considered based on mechanical inertia calculations developed by KIUC. Additional part load NPHRs and outputs were also estimated for the 2 x 1 Solar Titan 130 and 2 x 1 GELM2000 options to compare the respective operating flexibility for each option.

5.1 Grid Stability

As a result of sudden load changes, loss of generator-to-grid synchronization can cause unit trip, resulting in grid instability. To evaluate the grid stability effects resulting from the addition of each GenX option, the spinning energy storage per unit of capacity was estimated for each option based on values provided by the OEMs. The calculations considered representative CT and CT generator, and reciprocating engine and reciprocating engine generator inertia constants.

For comparison purposes, the calculations did not consider the spinning energy storage per unit output for the STG in the combined cycle configuration cases. The addition of an STG would provide more spinning energy momentum and positively contribute to any synchronization instabilities. This positive effect on grid stability was, however, considered in the options screening selection later discussed in Section 8.0.

The representative stored energy per unit of capacity results are presented in Table 5-1 and are subject to OEM validation. The results show that Options 2 and 3 (1x1 and 2x1 Solar Titan 130) offers the largest spinning energy and would provide better grid stability compared to the other GenX options. The existing KIUC generation units that would be offset by the GenX unit are KSP and SWDs with 2.13 and 2.27 stored energy per MW capacity. The GenX unit would therefore improve the KIUC system stored energy and improve stability.

Table 5-1
GenX Spinning Energy Storage Energy per Unit Capacity

Description	**Option 1 LM2500PE STIG 30**	**Option 2 1x1 Solar Titan 130**	**Option 3 2x1 Solar Titan 130**	**Option 4 1x1 LM2500PE**	**Option 5 1x1 LM2000**	**Option 6 2x1 LM2000**	**Option 7 2 x Wärtsilä 18V46**	**Option 8 2 x 1 Wärtsilä 18V46**
Prime Mover Model	Brush BDAX 7.193ER	ABB AMS 900LE	ABB AMS 900LE	Brush BDAX 7.193ER	Medeinsha 650L2X	Medeinsha 650L2X	ABB	ABB
Gross Generator Output, MW [1]	24.56	12.82	12.82	24.47	14.52	14.52	17.08	17.08
Generator Speed, rpm	3,600	1,800	1,800	3,600	3,600	3,600	514	514
Generator Rating, MVA	48.9	19.0	19.0	48.9	23.0	23.0	21.3	21.3
Moment of Inertia (J), kg-m^2								
Prime mover, gear, and coupling	75	2,383	2,383	75	75	75	4,900	4,900
Generator	750	1,207	1,207	750	370	370	13,000	13,000
Total	825	3,590	3,590	825	445	445	17,900	17,900
Inertia Constant (H), MW-s/MVA [2]								
Generator Only	1.09	1.13	1.13	1.09	1.14	1.14	0.88	0.88
Total Prime Mover and Generator	1.2	3.36	3.36	1.20	1.38	1.38	1.21	1.21
Stored Energy Comparison								
Stored Energy, MW-s	58.6	63.8	63.8	58.6	31.6	31.6	25.9	25.9
Stored Energy per MW Capacity	2.4	5.0	5.0	2.4	2.1	2.1	1.5	1.5

Notes:

1. Gross generator output represents output from a single generator.
2. Calculated by using the following equation:

$$H = \frac{1/2 \times J \times \omega^2}{S}$$

$where:$

$J = moment\ of\ inertia\ of\ the\ rotating\ mass\ (kg \times m^2)$

$\omega = synchronous\ angular\ velocity\ (rad/s)$

$S = volt\ ampere\ rating\ of\ the\ generator\ (V \times A)$

$further: \omega = rpm \times (2 \times \pi / 60)\ for\ a\ Hz\ system$

5.2 2 x 1 Combined Cycle Part Load Flexibility

The 2 x 1 combined cycle GenX options all consist of two CTs or two diesel generators, and one STG, and therefore inherently have the capability to operate over a larger range of varying part loads compared to the simple cycle and 1 x 1 combined cycle configurations and offer greater operating flexibility. To further assess the flexibility of Options 3, 6, and 8, Black & Veatch estimated net plant heat rates (NPHR) and outputs at varying part loads as shown in Table 5-2.

Table 5-2

NPHRs and Outputs over a range of Part Loads for the 2 x 1 GenX Options

Option	CT1 Load, percent	CT1 Output, MW	CT2 Load, percent	CT2 Output, MW	STG Load, percent	STG Output, MW	Net Plant Output, MW	NPHR (LHV), Btu/kWh	NPHR (HHV), Btu/kWh
Option 3 CCCT 2 x 1 Solar Titan 130	100	12.82	100	12.82	100	10.64	35.50	7,910	8,420
	100	12.82	0	0	50	5.27	17.61	7,970	8,490
	50	6.24	50	6.24	50	5.90	17.81	10,450	11,130
	50	6.24	0	0	25	2.84	8.76	10,630	11,320
	100	12.82	0	0	0	0	12.38	11,340	12,080
	50	6.24	0	0	0	0	5.95	15,650	16,670
Option 6 CCCT 2 x 1 LM2000	100	14.52	100	14.52	100	11.92	40.07	7,790	8,300
	100	14.52	0	0	50	6.07	19.99	7,810	8,320
	50	7.03	50	7.03	50	8.24	21.64	8,920	9,500
	50	7.03	0	0	25	3.72	10.38	9,300	9,900
	100	14.52	0	0	0	0	14.02	11,130	11,850
	50	7.03	0	0	0	0	6.69	14,440	15,380
Option 8 CCDE 2 x 1 Wärtsilä 18V46	100	17.08	100	17.08	100	2.98	36.26	7,190	7,660
	100	17.08	0	0	50	1.58	18.33	7,110	7,570
	50	8.51	50	8.51	50	1.96	18.31	7,430	7,910
	50	8.51	0	0	25	0.80	9.13	7,450	7,930
	100	17.08	0	0	0	0	16.78	7,760	8,260
	50	8.51	0	0	0	0	8.34	8,160	8,690

6.0 Preliminary Cost Estimates

This section discusses the preliminary capital and O&M cost estimates for the GenX options considered. These estimates were based on Black & Veatch's experience on similar projects, market information, OEM input, and a proprietary in-house database.

6.1 Capital Cost Estimates

Preliminary screening level overnight 2008 capital cost estimates for the GenX options were developed. All estimates are presented on an EPC basis exclusive of Owner's costs. Owner's cost should be considered by the project developer/owner to determine the total capital requirement for the project. Potential Owner's costs are listed in Table 6-1.

The following subsections provide the capital cost assumptions used to develop the estimates. These assumptions were broken down into the major capital cost estimate components consisting of general assumptions, direct and indirect cost assumptions.

The preliminary capital cost estimates are provided in Table 6-2. The estimates presented are reasonable for today's market, but as demonstrated in the last few years, the market is dynamic and unpredictable. Power plant costs are subject to continued volatility in the future, and the estimates in this report should be viewed with this in mind.

The estimate is presented as an engineer, procure and construct (EPC) approach. The estimate is broken into procurement packages. These procurement packages are then broken down as follows:

- Engineered Equipment Cost – These costs represent equipment that the EPC contractor would purchase and provide to the installing contractors.
- Construction – The estimate assumes multi- sub contractors managed by the EPC Construction Management staff will be hired to perform the construction and provide the balance of equipment and materials. The costs associated with this scope of work are provided.
- EPC Contract – Costs have been included representing the expected contingency, overhead and profit for an EPC contractor.

6.2 Direct Cost Assumptions

Direct cost assumptions are related to project scope and expand on the project definition. Direct cost assumptions are as follows:

- The subsurface conditions will be as determined by a subsurface investigation. For this estimate, the assumption is that the soil will support the foundation loads without any subsurface system. Spread footings are assumed for equipment foundations.
- For any of the options, the expansion will be adjacent to the existing GE LM 2500 STIG at the Lihue Energy Service Center.
- The site preparation will consist of removal of the top soil from the area for the expansion.
- The terminal points for service air will be at the existing compressors, naphtha and fuel oil will be at the tank farm, fire protection will connect to the existing underground loop.
- Roads for the expansion will be extended from the existing roads.
- No upgrade of demineralized water treatment piping is required.
- No sanitary facilities are required for the new unit.
- Construction power is available.
- Existing fire protection system is adequate to supply the new fire protection water needs.
- The existing site drainage retention system is adequate and is assumed to be accepted by the agencies.
- Noise requirements are 75 dBA at the site boundary and 85 dBA 3 feet from equipment.

6.3 General Cost Assumptions

The following are the general cost assumptions:

- Total direct capital costs are in second quarter of 2008 dollars and exclude any escalation to future years.
- Direct costs include the costs associated with the purchase of equipment, erection and contractors' service.
- Construction costs are based on use of a multiple union subcontractors for construction.
- Construction costs are based on a 50-hour week.
- Wage rates are based on union trades in the state of Hawaii.
- Field productivity rates are based expected rates for this region.
- Cost estimate is based on fixed price purchase orders and contracts being awarded through a competitive bidding process.

6.4 Indirect Cost Assumptions

The following are assumptions related to the construction and EPC indirect cost:

- General indirect costs include relay checkouts and testing, instrumentation and control equipment calibration and testing, systems and plant startup including operating crew during test and initial operation period, operating crew training, electricity, water and fuel used during construction, but no local taxes are included in this cost estimate.
- Engineering and related services are included for the EPC approach.
- Contractor field construction management services include field management staff including support staff personnel, field contract administration, field inspection and quality assurance, project control, technical direction and management of start up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, other required labor related insurance, and liability insurance for equipment and tools.
- A project profit margin and contractor estimating contingency is not included.
- Project insurance including general liability is included.
- Payment and performance bonds are excluded.
- No Federal, state, county, and local taxes are included.

Table 6-1
Potential Owner's Costs

Project Development:
- Site selection study
- Land purchase/options/rezoning
- Transmission/gas pipeline rights of way
- Road modifications/upgrades
- Demolition (if applicable)
- Environmental permitting/offsets
- Public relations/community development
- Legal assistance

Utility Interconnections:
- Natural gas service (if applicable)
- Gas system upgrades (if applicable)
- Electrical transmission
- Supply water
- Wastewater/sewer (if applicable)

Spare Parts and Plant Equipment:
- AQCS materials, supplies, and parts
- Steam turbine materials, supplies, and parts
- Boiler materials, supplies, and parts
- Balance-of-plant equipment/tools
- Rolling stock
- Plant furnishings and supplies

Owner's Project Management:
- Preparation of bid documents and selection of contractors and suppliers
- Provision of project management
- Performance of engineering due diligence
- Provision of personnel for site construction management

Plant Startup/Construction Support:
- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals/reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchase
- Construction all-risk insurance
- Acceptance testing
- Supply of trained operators to support equipment testing and commissioning

Taxes/Advisory Fees/Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Power Purchase Agreement (PPA)
  - Interconnect agreements
  - Contracts--procurement and construction
  - Property transfer

Owner's Contingency:
- Owner's uncertainty and costs pending final negotiation:
  - Unidentified project scope increases
  - Unidentified project requirements
  - Costs pending final agreement (e.g., interconnection contract costs)

Financing:
- Financial advisor, lender's legal, market analyst, and engineer
- Development of financing sufficient to meet project obligations or obtaining alternate sources of lending
- Interest during construction
- Loan administration and commitment fees
- Debt service reserve fund

Table 6-2
Estimated Capital Costs for GenX Options (Overnight EPC April 2008, $1,000)

Description	Option 1 LM2500PE STIG 30	Option 2 1x1 Solar Titan 130	Option 3 2x1 Solar Titan 130	Option 4 1x1 LM2500PE	Option 5 1x1 LM2000	Option 6 2x1 LM2000	Option 7 2 x Wärtsilä 18V46	Option 8 2 x 1 Wärtsilä 18V46
Purchase Contracts								
Civil / Structural	258	218	335	530	530	659	713	800
Mechanical	20,376	20,665	34,021	30,392	23,060	42,798	30,145	35,236
Electrical	2,681	2,534	3,283	3,061	3,065	3,821	1,826	2,154
Control	949	849	1,259	1,145	1,145	1,454	507	933
Chemical	730	539	553	514	203	567	25	485
Spares	492	352	567	503	413	670	694	820
Subtotal Purchase Contracts	*25,486*	*25,157*	*40,018*	*36,145*	*28,416*	*49,969*	*33,910*	*40,428*
Furnish and Erect Contracts								
Structural Equipment	--	625	625	486	486	625	--	--
Mechanical equipment	124	124	124	242	242	242	1,073	1,073
Subtotal F&E Contracts	*124*	*749*	*749*	*728*	*728*	*867*	*1,073*	*1,073*
Construction Contracts								
Civil / Structural Construction	2,998	2,830	3,496	6,187	5,680	7,293	3,672	4,353
Mechanical Construction	5,391	7,273	9,651	9,428	8,579	12,378	5,913	8,113
Electrical / Control Construction	4,728	3,921	4,873	5,608	5,555	6,829	2,665	3,936
Chemical Construction	182	153	163	161	48	173	--	90
Service Contracts & Construction Indirects	6,680	5,747	6,175	7,073	6,895	8,370	5,286	5,461
Subtotal Construction Contracts	*19,979*	*19,924*	*24,358*	*28,457*	*26,757*	*35,043*	*17,536*	*21,953*
Total Direct Costs	**45,589**	**45,830**	**65,125**	**65,330**	**55,901**	**85,879**	**52,519**	**63,454**
Total Indirect Costs	**8,935**	**8,983**	**12,765**	**10,779**	**9,224**	**14,170**	**10,294**	**12,437**
Total EPC Requirements:	**54,524**	**54,813**	**77,890**	**76,109**	**65,125**	**100,049**	**62,813**	**75,891**
Net Plant Output, MW	24.26	17.37	35.50	33.91	19.54	40.07	33.59	36.26
Specific EPC Cost, $/kW	**2,247**	**3,156**	**2,194**	**2,244**	**3,333**	**2,497**	**1,870**	**2,093**

6.5 O&M Cost Estimates

Preliminary screening level estimates of O&M expenses, including fixed and non-fuel variable annual expenses were developed for each of the seven options. The estimates are expressed in second quarter 2008 dollars.

Fixed O&M costs are those that do not vary directly with plant electrical production. The largest components of fixed O&M costs are wages and wage-related overheads for the permanent plant staff. Variable O&M costs change as a function of plant generation. Variable O&M costs include costs associated with outage maintenance, reagents and chemicals. The unit fixed and non-fuel variable O&M costs are based on the estimated net plant output at average day ambient conditions.

All O&M estimates were generated on a consistent basis. Assumptions used to develop the performance estimates were also used to develop the O&M estimates. Operating assumptions specific to the development of the O&M estimates are provided in Table 6-3.

For the GE LM2500 CTs running on liquid fuel, each will require its first hot section refurbishment at 12,500 hours intervals until they reach 50,000 hours at which time they will receive an engine overhaul. Each hot section refurbishment requires the removal and exchange of the existing hot section which typically takes about 4 days. For the engine overhaul, the existing engine is removed and replaced with a lease engine until the original engine has been overhauled and returned to the client. At this time the original engine is reinstalled at the site and the lease engine is returned to the supplier. The removal and installation typically takes about 4 days and should be scheduled to coincide with a steam turbine outage. The GE LM2000 CTs have a similar schedule except they only require one hot section refurbishment at 25,000 hours and then a major overhaul at 50,000 hours.

Under the Solar Titan 130 maintenance schedule, each CT is replaced with a refurbished engine about every 25,000 hours. The replacement typically takes about 4 days and does not require that the client reinstall the original CT.

Planned outage factors for each option were determined based on equipment outage maintenance requirements as well as information obtained from the North American Electric Reliability Corporation (NERC) database. Forced outage factors for each option were also determined from a query of the NERC database. Duration and frequency of inspections for the CTs are based on data and input from each OEM. Steam Turbine outage duration and frequency are based on manufacturer input and Black & Veatch experience.

Table 6-3
O&M Assumptions

Description	**Unit**	**Option 1** **LM2500 STIG 30**	**Option 2** **1x1 Solar Titan 130**	**Option 3** **2x1 Solar Titan 130**	**Option 4** **1x1 LM2500**	**Option 5** **1x1 LM2000**	**Option 6** **2x1 LM2000**	**Option 7** **2 x Wärtsilä**	**Option 8** **2 x 1 Wärtsilä**
Key O&M Inputs, April 2008$									
Dry Urea[1]	$/ton	950	950	950	950	950	950	950	950
Water Costs [2]	$/gal	0	0	0	0	0	0	0	0
SCR Catalyst Costs	$\$/m^3$	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Staff	Persons	7	11	11	9	9	11	9	11
Payroll Burden [3]	Percent	See Note 3	See Note 3	See Note 3	See Note 3	See Note 3	See Note 3	See Note 3	See Note 3
Operating Factors									
Base Loaded Operation	Hr/yr	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884
Starts per Year	Hr/yr	52	52	52	52	52	52	52	52
Reserve Shutdown Hours	Hr/yr	350	175	175	175	220	175	175	0
Availability Factor	Percent	94.0	92.0	92.0	92.0	92.5	92.0	92.0	89.9
Capacity Factor	Percent	90.0	90.0	90.0	90.0	90.0	90.0	90.0	89.9
Planned Outage Factor, Annualized	Percent	2.0	2.0	2.0	2.5	2.0	2.0	4.0 [10]	4.1
Forced Outage Factor	Percent	4.0	6.0	6.0	5.5	5.5	6.0	4.0 [10]	6.0
Outage Maintenance									
CTG Inspection Duration	Days	1	1	1	1	1	1	See Note 8	See Note 8
CTG Inspection Frequency	Yrs/Outage	0.5	0.5	0.5	0.5	0.5	0.5	See Note 8	See Note 8
CTG Hot Gas Path Inspection Duration [4]	Days	4	4 (See Note 6)	4 (See Note 6)	4	4	4	See Note 8	See Note 8
CTG Hot Gas Path Inspection Frequency [5]	Yrs/Outage	1.5	3 (See Note 6)	3 (See Note 6)	1.5	3	3	See Note 8	See Note 8
CTG Major Inspection Duration[6]	Days	8	n/a	n/a	8	8	8	See Note 8	See Note 8
CTG Major Inspection Frequency[6]	Yrs/Outage	6	n/a	n/a	6	6	6	See Note 8	See Note 8
STG Outage Duration[7]	Days	n/a	21	21	21	21	21	21	21
STG Outage Frequency[7]	Yrs/Outage	n/a	6	6	6	6	6	6	6

Notes:

1. Dry Urea costs assumed as $950/ton as provided by KIUC.
2. Water costs were assumed as $0 per gallon as provided by KIUC.
3. Average fully burdened plant operator salaries are based on $120,000/year which includes 28% overtime, provided by KIUC.
4. The four day CTG hot gas path and major outage duration assumes the client has elected to pay for the optional lease engine agreement.
5. The O&M estimate was based on using liquid fuel which resulted in additional Hot Section Refurbishments over the life of each GE CT compared to the operation of each GE CT on natural gas.
6. Under the Solar Titan 130 agreement, each CT is exchanged with a replacement at the Hot Gas Path Inspection interval.
7. Steam Turbine annual inspection duration and frequency are estimated based on manufacturer input and Black & Veatch experience.
8. Outage maintenance does not follow a CI, HPG, Major outage schedule. Varying levels of maintenance typically done at 4,000 hour intervals per the OEM. Maintenance level of detail too complicated for this table.
9. Planned outage factor and forced outage factor reflect data obtained from similar size units from Black & Veatch experience.
10. OEM commented that they do not track POF & FOF, but did provide availability numbers based on planned outages and forced outages.

Table 6-4

Preliminary GenX O&M Costs (Overnight April 2008$, $1,000)

Description	**Option 1 LM2500 STIG 30**	**Option 2 1x1 Solar Titan 130**	**Option 3 2x1 Solar Titan 130**	**Option 4 1x1 LM2500**	**Option 5 1x1 LM2000**	**Option 6 2x1 LM2000**	**Option 7 2 x Wärtsilä 18V46**	**Option 8 2 x 1 Wärtsilä 18V46**
Fixed Costs								
Labor								
Operations	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
Maintenance	240.0	480.0	720.0	480.0	480.0	720.0	480.0	720.0
Labor Subtotal	*840.0*	1,080.0	*1,320.0*	*1,080.0*	*1,080.0*	*1,320.0*	*1,080.0*	*1,320.0*
Maintenance								
CT (borescope)/ Recip Engine	25.0	25.0	50.0	25.0	25.0	50.0	39.4	39.4
Combustion Turbine(ann. lease fee)	112.4	0.0	See Notes[1]	112.4	112.4	224.9	n/a	n/a
Steam Turbine & Steam Plant	n/a	1.5	3.2	3.1	1.6	3.6	n/a	0.9
HRSG	0.6	1.2	2.7	2.5	1.4	3.0	n/a	0.7
Air Cooled Condenser	0.0	3.1	6.8	6.5	3.5	7.7	n/a	1.9
Water Treatment Facilities	1.8	2.6	5.3	5.1	2.9	6.0	n/a	5.4
Waste Water Treatment	0.9	1.3	2.7	2.5	1.5	3.0	1.3	2.7
Pollution Control	1.2	0.9	1.8	1.7	1.0	2.0	1.7	1.8
I&C and Electric Plant	3.6	2.6	5.3	5.1	2.9	6.0	5.0	5.4
Contracted Services	6.1	4.3	8.9	8.5	4.9	10.0	8.4	9.1
Maintenance Subtotal	*151.7*	42.5	*86.7*	*172.5*	*157.1*	*316.2*	*55.8*	*67.4*
Other Expenses								
Training	14.0	18.0	22.0	18.0	18.0	22.0	18.0	22.0
Property Taxes	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner
Office & Admin. Expenses	42.0	54.0	66.0	54.0	54.0	66.0	54.0	66.0
Bonus and Incentive Pay	42.0	54.0	66.0	54.0	54.0	66.0	54.0	66.0
Insurance	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner	By Owner
Other Fees	6.1	4.3	8.9	8.5	4.9	10.0	8.4	9.1
Subtotal Other Fixed Expenses	*104.1*	130.3	*162.9*	*134.5*	*130.9*	*164.0*	*134.4*	*163.1*
Total Fixed Costs	**1,095.8**	**1,252.9**	**1,569.5**	**1,386.9**	**1,368.0**	**1,800.2**	**1,270.2**	**1,550.5**
Variable Costs								
Outage Maintenance								
CT/Reciprocating Engine	986.5	667.7	1,335.5 [1]	986.5	599.4	1,198.7	1,404.6	1,404.6
Steam Turbine	n/a	10.0	18.8	18.1	11.0	20.6	n/a	6.9
Generator	15.0	15.0	15.0 [1]	30.0	30.0	45.0	30.0	45.0
SCR Catalyst Replacement	63.3	62.8	110.6	66.8	54.0	108.0	61.9	61.9
HRSG	1.9	4.0	8.7	8.4	4.5	9.8	n/a	2.4
Subtotal Outage Maintenance	*1,179.2*	*759.5*	*1,488.5*	*1,109.8*	*698.9*	*1,382.1*	*1,496.5*	*1,365.0*
Utilities								
Water	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sewage	1.3	2.6	4.1	3.2	3.0	4.6	1.1	1.5
Subtotal Utilities	*1.3*	2.6	*4.1*	*3.2*	*3.0*	*4.6*	*1.1*	*1.5*
Chemical Usage								
Treatment/Pre-Treatment	143.5	41.3	81.8	72.6	35.3	69.7	0.9	3.5
SCR Ammonia Consumption (Urea)	161.0	206.0	411.9	179.8	112.3	224.7	2,336.8	2,336.8
Lube Oil Consumption	-	-	-	-	-	-	260.0	260.0
Subtotal Chemical Usage	*304.5*	*247.3*	*493.7*	*252.3*	*147.7*	*294.4*	*2,597.8*	*2,600.4*
Total Variable Costs	**1,372.5**	**1,009.5**	**1,986.3**	**1,365.3**	**849.5**	**1,681.2**	**4,095.4**	**4,122.7**
Total O&M Cost	**2,468.3**	**2,262.3**	**3,555.9**	**2,752.3**	**2,217.5**	**3,481.4**	**5,365.6**	**5,673.2**
Net Annual Generation, MWh	**191,289**	**136,921**	**279,890**	**267,315**	**154,022**	**315,936**	**264,824**	**285,842**
Fixed Costs, $/kW-yr	**45.16**	**72.14**	**44.21**	**40.91**	**70.03**	**44.92**	**37.81**	**42.77**
Variable Costs, $/MWh	**7.18**	**7.37**	**7.10**	**5.11**	**5.52**	**5.32**	**15.46**	**14.42**

Notes:

1. Combustion Turbine Outage Maintenance includes full maintenance coverage for both CTs, both CT generators and the annual lease engine fees per vendor data.
2. All values are based on the assumptions provided in Table 6-3.

7.0 Economic Analysis

A busbar analysis was developed to compare the seven technologies. The economic criteria, summary of inputs, and results are presented in this section. For the purposes of this study, Black & Veatch assumed a commercial operation date (COD) in April 2011 for all seven technologies.

7.1 Economic Criteria

The economic criteria utilized for the busbar analysis are summarized in Table 7-1.

Table 7-1
Levelized Busbar Cost Analysis Assumptions

General Inflation	Percent	3.0
Present Worth Discount Rate	Percent	5.0
Interest During Construction Interest Rate	Percent	5.0
Owner’s Cost Adder	Percent	10
Levelized Fixed Charge Rate	Percent	7.195
Debt Term	Years	20
Capacity Factor	Percent	90
Fixed O&M Escalation	Percent	3
Variable O&M Escalation	Percent	3

7.2 Busbar Cost Analysis

Levelized busbar cost analyses for each of the options for were performed using the following sets of data:

- Estimated EPC capital costs, shown in Table 6-2.
- O&M cost estimates, shown in Table 6-3.
- Performance estimates, shown in Table 4-2.
- Economic assumptions, shown in Table 7-1.
- Fuel Oil Forecasts in Tables A-1 to A-3 in Appendix A.

7.2.1 No. 2 Fuel Oil and Naphtha Considerations

The thermal performance results presented in Section 4 were based on all options firing No. 2 ultra-low sulfur fuel oil. Levelized busbar costs analyses were conducted for base, high, and low No. 2 fuel cost cases according to the No. 2 fuel forecasts in Tables A-1 through A-3 in Appendix A.

To evaluate the effect of fuel cost when firing Naphtha for all the CT options, levelized busbar cost analyses were also run for base, high, and low Naphtha fuel cost cases according to the fuel forecasts in Tables A-1 through A-3 in Appendix A. The Naphtha levelized busbar costs were based on the thermal performance values and O&M costs developed for No. 2 fuel are therefore only intended to reflect the relative differences between the cost of production associated with the No. 2 fuel oil and Naphtha fuel forecasts, respectively.

7.2.2 Levelized Busbar Cost Results

The results of the busbar cost analysis, shown in Table 7-2 are based on an April 2011 unit commercial operation date. The preliminary results indicate Option 4, the 1x1 GE LM2500 PE, is the low cost technology choice among the configurations studied. This is due largely to the lower capital cost and plant heat rate.

The results also indicate that the CT options will have an approximate 2.5 percent lower cost of production when firing Naphtha compared to No. 2 Fuel oil.

Table 7-2
Levelized Busbar Cost Analysis Results

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
Description	**LM2500 STIG 30**	**1x1 Solar Titan 130**	**2x1 Solar Titan 130**	**1x1 LM2500**	**1x1 LM2000**	**2x1 LM2000**	**2 x Wärtsilä 18V46**	**2 x 1 Wärtsilä 18V46**
Capital Cost Estimates ($1,000)								
Total EPC Capital Cost, April 2008$	54,524	54,813	77,890	76,109	65,125	100,049	62,813	75,891
Assumed Construction Duration, months	10	14	15	14	14	15	10	15
Escalated EPC Capital Cost, April 2011$	62,713	62,223	88,134	86,399	73,930	113,207	72,247	85,872
Owner’s Cost Adder, April 2011$	6,271	6,192	8,813	8,640	7,393	11,321	7,225	8,587
Interest During Construction, April 2011$	1,600	2,293	3,498	3,184	2,725	4,493	1,843	3,408
Total Project Cost, April 2011$	70,584	70,739	100,445	98,223	84,048	129,020	81,315	97,867
O&M Cost Estimates								
Fixed O&M Cost, April 2008$	45.16	72.14	44.21	40.91	70.03	44.92	37.81	42.77
Fixed O&M Cost, April 2011$	49.35	78.83	48.31	44.70	76.52	49.09	41.32	46.74
Variable O&M Cost, April 2008$	7.18	7.37	7.10	5.11	5.52	5.32	15.46	14.42
Variable O&M Cost, April 2011$	7.85	8.05	7.76	5.58	6.03	5.81	16.89	15.76
Performance Estimates								
Net Power Output (HHV), kW	24,260	17,370	35,500	33,910	19,540	40,070	33,590	36,260
Net Plant Heat Rate (HHV), Btu/kWh	9,730	8,610	8,420	7,760	8,500	8,290	8,260	7,652
Capacity Factor, percent	90	90	90	90	90	90	90	88
Busbar Results								
Base Case Fuel Forecasts								
Base Case No. 2 Fuel Forecast Levelized Busbar Analysis Result, c/kWh	27.3	26.3	24.2	22.3	25.9	24.0	24.5	23.2
Base Case Naphtha Fuel Forecast Levelized Busbar Analysis Result, c/kWh	25.6	24.7	22.6	20.9	24.4	22.5	-	-
Estimated cost savings resulting from firing Naphtha, c/kWh	1.7	1.6	1.6	1.4	1.5	1.5		
High Case Fuel Forecasts (1)								
High Case No. 2 Levelized Busbar Analysis Result, c/kWh	32.9	31.2	29.0	26.8	30.8	28.7	29.2	27.6
High Case Naphtha Levelized Busbar Analysis Result, c/kWh	31.9	30.3	28.1	26.0	29.9	27.8	-	-
Low Case Fuel Forecasts (1)								
Low Case No. 2 Levelized Busbar Analysis Result, c/kWh	18.6	18.6	16.6	15.4	18.3	16.6	17.1	16.4
Low Case Naphtha Levelized Busbar Analysis Result, c/kWh	15.7	16.0	14.1	13.1	15.8	14.1	-	-

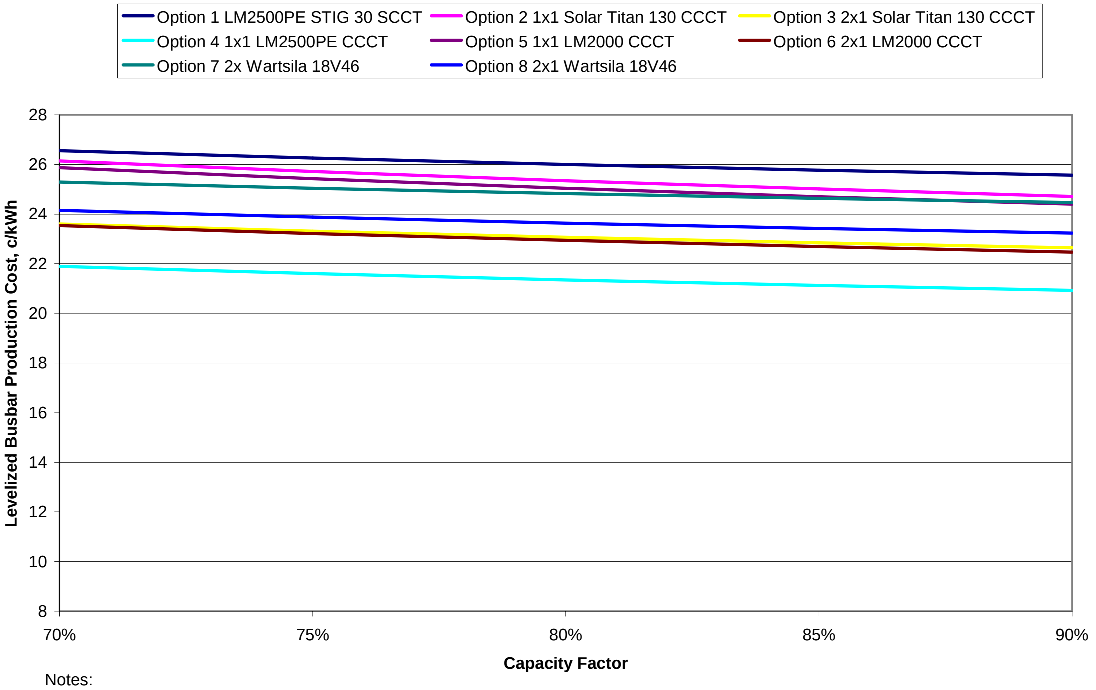
Notes:

1. Fuel Forecasts to be provided by KIUC
2. Based on economic assumptions in Table 7-1, full load performance values at average annual ambient conditions, and fuel forecasts in Appendix A.
3. Busbar results with Naphtha fuel forecasts are based on performance and O&M estimates developed for No. 2 fuel oil.

7.3 Busbar Sensitivity Analysis

Two sensitivity analyses were run for the busbar costs. The first sensitivity analysis was developed for the GenX options using capacity factors ranging from 70 percent to 90 percent. The analysis considered the base case No 2 fuel oil forecast for the reciprocating engine options, and the base case Naphtha fuel forecast for the CT options. The O&M costs in Table 6-4, and the thermal performance estimates in Table 4-2 were consistently applied for all options. In reality, the O&M costs would slightly increase with declining capacity factors.

Figure 7-1 shows the results of sensitivity analysis. Operating the units at higher capacity factors would result in lower costs of production.



Notes:
- All CT busbars assumed Naphtha fuel forecasts. Thermal performance and O&M estimates based on firing No. 2 fuel oil
- Both reciprocating engines assumed No. 2 fuel forecast with corresponding No. 2 fuel oil thermal performance and O&M

Figure 7-1. Levelized Cost of Production vs. Varying Capacity Factors

The second sensitivity analysis used high and low fuel cost cases to estimate busbar costs. The results of this analysis are shown in Table 7-2.

8.0 Options Screening

Three options are notable among all those reviewed: the 1x1 LM2500, the 1x1 Solar Titan and the 2x1 Solar Titan.

- The 1x1 LM2500 PE option has the lowest busbar cost and lowest heat rate among the three.
- The 1x1 and 2x1 Solar Titan options have considerably better grid stability characteristics than the LM 2500, which may outweigh the cost and performance benefits of the LM 2500.

Additional IRP benefits may be discovered that are beyond the busbar cost analysis that was performed for this study. These could include infrastructure requirements, such as availability of transmission or water, or compatibility with forecasted load requirements.

Appendix A. Fuel Forecast

Table A-1
Base Case Fuel Forecast

Year	No. 2 Fuel Oil Cents/Gallon	No. 2 Fuel Oil $/MBtu	Naphtha Cents/Gallon	Naphtha $/MBtu
2011	264	19.2	211	17.4
2012	257	18.8	205	17.0
2013	257	18.8	205	17.0
2014	265	19.4	212	17.6
2015	266	19.4	213	17.6
2016	267	19.5	214	17.7
2017	276	20.2	222	18.4
2018	289	21.1	233	19.3
2019	309	22.5	251	20.7
2020	327	23.9	267	22.1
2021	335	24.4	274	22.6
2022	349	25.5	286	23.7
2023	362	26.4	298	24.6
2024	375	27.3	309	25.5
2025	392	28.6	325	26.8
2026	411	30.0	341	28.2
2027	428	31.3	356	29.5
2028	446	32.6	372	30.8
2029	467	34.1	390	32.3
2030	490	35.7	410	33.9

Table A-2
High Case Fuel Forecast

Year	No. 2 Fuel Oil Cents/Gallon	No. 2 Fuel Oil $/MBtu	Naphtha Cents/Gallon	Naphtha $/MBtu
2011	288	21.0	235	19.4
2012	293	21.4	241	19.9
2013	307	22.4	255	21.1
2014	322	23.5	269	22.2
2015	331	24.2	278	23.0
2016	344	25.1	291	24.0
2017	362	26.4	307	25.4
2018	377	27.5	321	26.6
2019	396	28.9	338	28.0
2020	416	30.4	356	29.4
2021	435	31.7	374	30.9
2022	452	33.0	389	32.2
2023	464	33.8	399	33.0
2024	478	34.9	413	34.1
2025	493	36.0	426	35.2
2026	512	37.4	442	36.5
2027	531	38.8	459	37.9
2028	554	40.4	480	39.6
2029	576	42.1	500	41.3
2030	601	43.9	522	43.1

Table A-3
Low Case Fuel Forecast

Year	No. 2 Fuel Oil		Naphtha	
	Cents/Gallon	$/MBtu	Cents/Gallon	$/MBtu
2011	226	16.5	174	14.4
2012	204	14.9	152	12.6
2013	185	13.5	133	11.0
2014	178	13.0	125	10.3
2015	162	11.8	109	9.0
2016	144	10.5	91	7.5
2017	146	10.6	91	7.5
2018	152	11.1	96	8.0
2019	167	12.2	109	9.0
2020	186	13.6	126	10.4
2021	181	13.2	120	9.9
2022	192	14.0	130	10.7
2023	205	15.0	141	11.6
2024	214	15.7	149	12.3
2025	231	16.9	163	13.5
2026	248	18.1	178	14.7
2027	262	19.1	190	15.7
2028	277	20.2	203	16.7
2029	295	21.6	219	18.1
2030	313	22.9	234	19.4