Final Report

Interim Renewable Infusion Study

Caribbean Utilities Company, Ltd.

March 14, 2017

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Table of Contents

List of Appendices

List of Tables

List of Figures

EXECUTIVE SUMMARY

Leidos Engineering, LLC (Leidos) has completed the Renewable Infusion Study (Study) for Caribbean Utilities Company, Ltd. (CUC) to assist with the expansion of CUC's renewable energy portfolio while maintaining current levels of reliability, power quality, and life cycle generation and transmission and distribution costs. This Study was prepared to determine the capacity of intermittent (non-base load) renewable energy (RE) installations, including export only utility-scale and rooftop distributed customer-scale, that can be connected to the electric system without compromising its stability.

The analysis and results presented in this study are based on the following scenarios.

- They do not require CUC to employ additional generator operating or spinning reserve while maintaining load dispatch to units at a level greater than 65% of the existing generation's rated capacity. In addition, there are several key assumptions considered in this study, which strongly correlates with the stated outcomes.
  - Please note the existing CUC practice is to operate the generators at or above 80% of rated capacity
- Reverse power flow through distribution feeders and substation transformers not permitted
- Projected load growth on the CUC system was not considered
- Integration of Battery Energy Storage Systems (BESSs) was not included
- Analysis included integration of the planned Seven Mile Beach Substation and distribution feeders
- Analysis also included a new, dedicated feeder from Bodden Town Substation to serve a 5 MW approved solar generation site
- Conductor and equipment loading was limited to 100% of the rated capacity
- RE installations were assumed to operate at unity power factor

This report summarizes the analysis, findings, and recommendations.

Conclusion

Based on the analysis described herein, no changes are required to the CUC system or its operation to achieve a renewable penetration level of 11.5 MW with the implementation of the recommended ride-through criteria given in Table 1-6. The analysis revealed the total renewable capacity that can be added to the system without reducing the present levels of reliability and quality is dependent on existing CUC generation units and their operation. Consequently, a renewable penetration level of 29 MW can be achieved if the existing North Sound Plant generators are operated, as required, at 65% of the rated capacity (instead of the existing practice of 80%). The results also support the addition of smaller, distributed renewable installations to minimize the potential impact of the renewables' variability on the system operation.

Although CUC has indicated that the existing plant generators are technically capable of operating intermittently at 65% of the rated capacity, CUC is encouraged to determine if it is economically favorable to adjust the existing operating reserves to achieve renewable penetration above 11.5 MW versus the addition or combination of solutions such as Battery Energy Storage System (BESS), predictive demand management, etc. Table ES-1 provides a summary of the study findings and recommendations.

Table ES-1
Summary of Findings & Recommendations

Total Renewable Capacity Threshold	Description of Renewables	Limiting Factor	Mitigation Required to Achieve Total Renewable Capacity Threshold
9 MW	**Baseline:** Installed & applicants for customer-owned RE plus proposed 5 MW Lakeview site	• None observed	• Ride-through criteria must meet recommended requirements
Above 9MW to 11.5MW	**Scenario 1 & 2:** Maximize utility-scale or customer-owned RE up to 11.5MW	• Generators operated at 80% of max rated capacity (existing criteria)	• No additional requirements above the recommended ride-through criteria
Above 11.5MW to 29.0MW	**Scenario 3 & 4:** Maximize utility-scale or customer-owned RE up to 29MW	• Generators operated at 65% of max rated capacity, as required	• Ride-through criteria must meet recommended requirements • Economically assess options for adjusting operating reserve
Above 29.0 MW	**Not Evaluated**		

Additional details of the findings and recommendations are given below, and further discussed in Section 2 and Section 3 of this report.

- The maximum allowable renewable penetration under existing generation dispatch practices (e.g., ~ operating units at 80% of the max. capacity rating) is 11.5 MW. Should adjustments to the dispatch practices be made (e.g., ~ operating units at 65% of the max. capacity rating), an additional 17.5 MW (29 MW total) would be achievable. The economic impacts for such an adjustment versus the addition or combination of solutions such as BESS, predictive demand management, etc. were not considered as part of this study.
- The ride-through criteria given in Table 1-6 and evaluated herein should be shared with all existing and future interconnecting customers/developers.
- A risk-benefit analysis should be performed to assess if a separate operating reserve (which could be a combination of spinning and non-spinning), beyond the contingency reserve, can be economically justified to manage increased levels of variable generation in day to day operation.

- The capacity of the existing transmission and distribution infrastructure to serve RE without causing reverse flow, capacity or system voltage issues significantly exceeds the system limitation of 29 MW.
- Future utility-scale installations on the east end of the island can be added the Frank Sound and Prospect substations; however, the total capacity should be limited such that reverse flow on the substation transformers and distribution feeders is prevented.
- The additional fault contribution from the anticipated renewable generation sources should have a negligible impact on the overcurrent device duty ratings and coordination of CUC’s T&D Feeders.
- Line devices (such as fuses, reclosers, sectionalizers, etc.) may need to be evaluated individually for larger renewable generation installations and be modified to have reverse flow capability.
- Distribution losses are improved when customer-scale renewables are maximized versus utility-scale renewables.
- The Ocean Thermal Energy Conversion (OTEC) plant, consisting of four 2.5 MW units as a first phase, can serve as a renewable substitute for a comparable CUC unit; however, spinning reserve requirements would still need to be met. Additionally, its inclusion will cause a slight degradation to the electric system’s reliability response when compared to the results found herein.
- Should additional capacity be added to the OTEC plant, it is recommended that a study be performed to evaluate the impact. Previous studies, performed by Leidos, showed a significant impact to system reliability for a larger plant interconnection. A number of additional recommendations and mitigations would need to be considered.

Additional Considerations

- With system load growth at the distribution level and/or load transfers between substations to increase loading, additional renewable generation may be considered on an individual basis while still considering the limit of PV per substation transformer and/or feeder as daytime light loading.
- The analysis contained herein limited renewable penetration levels on the distribution substation transformers and feeders such that reverse flow would be avoided to minimize the impacts on system voltage and equipment operations and controls. Reverse flow on the substation transformers and feeders may be acceptable, but should be evaluated by CUC to confirm the desired system performance is maintained.
- Resources and programs such as demand side management, compressed air, and other storage mechanisms could help to increase operating reserve during cloud cover and other system events that could cause large swings in renewable generation output. CUC should consider and perform near term operational planning studies as

renewable generation penetration increases towards the maximum levels studied herein.

- Larger renewable generation installations should be evaluated independently to verify system impacts and identify if facility improvements are required.

General Basis of Study

In the preparation of this Study report, including the opinions contained herein, certain assumptions and considerations were made with respect to conditions that may occur in the future. The analysis was performed using the available data and assumptions contained herein. Milsoft's WindMil® and Siemens Power Technologies International's (PTI) PSS®E (PSS/E) software was used to analyze the CUC generation and distribution and transmission facilities. While these considerations and assumptions are reasonable and reasonably attainable based on conditions known as of the date of this report, they are dependent on future events. Actual conditions may differ from those assumed herein or from the assumptions provided by others; therefore, the actual results will vary from those estimated.

1.1 Introduction

Leidos Engineering, LLC (Leidos) has completed the Renewable Infusion Study (Study) for Caribbean Utilities Company, Ltd. (CUC) to determine the capacity of intermittent (non-baseload) renewable generation installations that can be connected to the electric system without compromising its stability. The Study evaluated both the distribution and transmission electric systems and was performed in accordance with CUC's existing Transmission and Distribution Code (T&D Code). This report summarizes the analysis, findings, and recommended system modifications.

1.2 Background

CUC operates as the sole public electric utility in Grand Cayman. It supplies the electric energy needs of the community under license issued by the Electricity Regulatory Authority (ERA) on behalf of the Cayman Islands Government.

The CUC transmission and distribution system on Grand Cayman consists of seven 69 kV substations and switching stations, approximately 277 miles of overhead 69 kV and 13 kV circuits and 14 miles of 69 kV submarine cable. The local generation is supplied by sixteen (16) reciprocating engine generators and two (2) combustion turbine generators with a total capacity of approximately 153 MW. These units are located at the North Sound Power Plant site.

1.2.1 Seven Mile Beach

The addition of a proposed new substation, Seven Mile Beach, was included as part of the analysis. The substation is planned to be in-service by 2018, and its location is proposed near the voltage regulators located near Camana Bay. For purposes of this analysis, only customer loads on North Sound Feeders 9 and 10 were connected to this new substation. The substation will interconnect to the transmission system through the existing Line 1, Hydesville – North Sound 69 kV #1.

1.3 Installed Renewable Generation & Applications

The baseline for the system analysis was developed to incorporate the existing and previously queued level of renewable generation penetration on the CUC system. Table 1-1 includes the amount and location by substation. The locations of the existing and proposed renewables are identified on the system map included in Appendix A.

Table 1-1
Installed Renewable Generation & Applications

Substation	Total Installed (kW)
Seven Mile Beach	820.2
Bodden Town	5,201.8
Frank Sound	112.8
Hydesville	456.8
North Sound	1,413.4
Prospect	518.0
Rum Point	26.4
South Sound	450.7
Total System	**9,000.0**

Note: Total includes one 5 MW utility scale PV plant at Bodden Town Substation (Lakeview PV Farm scheduled for 2017). Remaining is customer-scale PV.

1.4 System Loading

CUC provided system load information to help Leidos determine realistic daytime loads to use as a basis for the analysis. Historical loads were evaluated to determine system daytime peak and daytime light load (or off-peak) load levels for use in the infusion study analysis. Typical load profile information was provided by CUC, which is illustrated in Figure 1-1 below. Based on the load profile provided, a daytime peak of 100 MW and daytime light load of 70 MW was selected for the study.

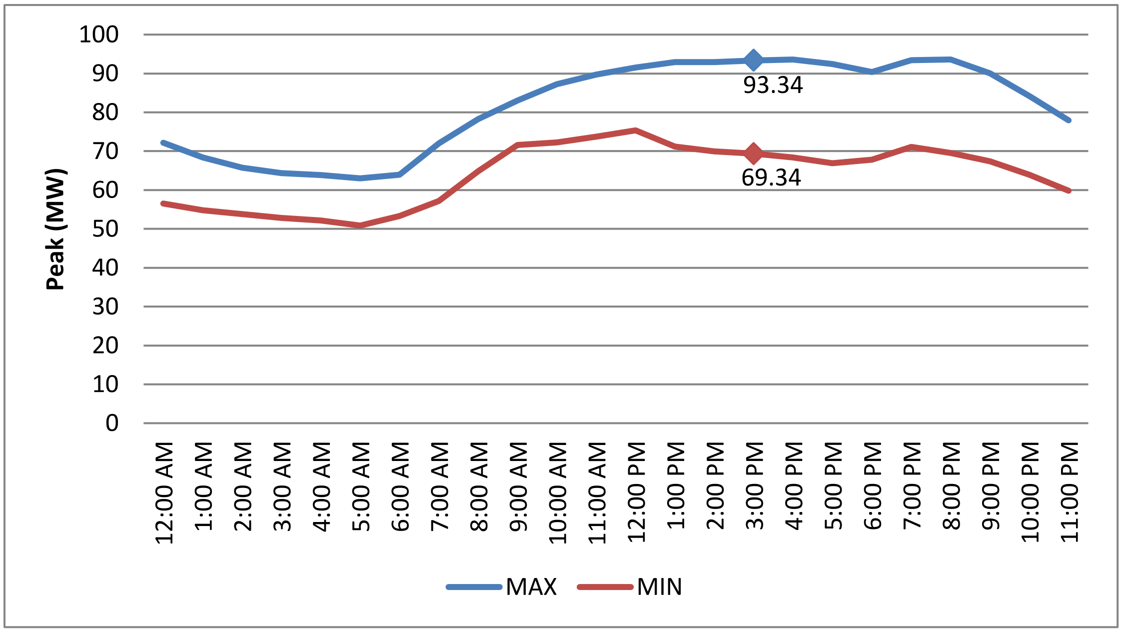

Figure 1-1. Typical Load Profile (August 2015)

1.5 Analysis Scenarios

To determine the maximum system level PV penetration for the CUC system, Leidos and CUC developed a strategy for analysis that includes multiple scenarios incorporating utility-scale and customer-scale PV. Scenarios include existing CUC local generation dispatched considering typical operation practices currently used (e.g., ~operation at 80% of max rated capacity) or reduced local generation (e.g., ~operation at 65% of max. rated capacity) maximizing renewable capability.

The renewables were modeled based on various levels of each type of installation (e.g., customer-scale and utility-scale) and evaluated at both a distribution and transmission level under daytime peak load and daytime light load conditions to determine the reliability and effectiveness of the CUC system. Considerations such as customer loads, system losses, and spinning reserve margins were used to determine the maximum levels of renewable penetration. Four scenarios in addition to the system Baseline were evaluated to determine the limitations of the existing system, which included:

- **Baseline:** Installed & applicants for customer-owned renewable installations plus proposed 5 MW Lakeview site
- **Scenario 1:** Maximize utility-scale renewable installations plus Baseline with operation at 80% of max rated generator capacity
- **Scenario 2:** Maximize customer-owned renewable installations plus Baseline with operation at 80% of max rated generator capacity
- **Scenario 3:** Maximize utility-scale renewable installations plus Baseline with operation at 65% of max rated generator capacity
- **Scenario 4:** Maximize customer-owned renewable installations plus Baseline with operation at 65% of max rated generator capacity

Table 1-2 summarizes the different scenarios and options analyzed as part of the study. A map of the existing renewable locations and areas of interest for the projected scenarios is included in Appendix A.

Table 1-2
Scenario Analysis Summary

Scenario Name	Load Scenario	CUC Generation	Renewable Generation					Analysis Type
			Customer Scale		Utility Scale		Total	
			Existing	Proposed	Existing	Proposed		
CUC Generation Dispatched at ~ 80% Capacity								
Baseline	Peak Daytime	**94.0**	4.0		5.0		**9.0**	Distribution Transmission
Baseline	Light Daytime	**63.4**	4.0		5.0		**9.0**	Distribution Transmission
Scenario 1	Peak Daytime	**91.5**	4.0		5.0	2.5 [1]	**11.5**	Distribution Transmission
Scenario 1	Light Daytime	**60.9**	4.0		5.0	2.5 [1]	**11.5**	Distribution Transmission
Scenario 2	Peak Daytime	**91.5**	4.0	2.5 [2]	5.0		**11.5**	Distribution
Scenario 2	Light Daytime	**60.9**	4.0	2.5 [2]	5.0		**11.5**	Distribution
CUC Generation Dispatched at ~ 65% Capacity								
Scenario 3	Peak Daytime	**74.2**	4.0		5.0	20.0 [3]	**29.0**	Distribution Transmission
Scenario 3	Light Daytime	**43.9**	4.0		5.0	20.0 [3]	**29.0**	Distribution Transmission
Scenario 4	Peak Daytime	**74.2**	4.0	20.0 [2]	5.0		**29.0**	Distribution
Scenario 4	Light Daytime	**43.9**	4.0	20.0 [2]	5.0		**29.0**	Distribution

Notes:
[1] Proposed utility-scale renewables served by a new dedicated feeder at the Frank Sound Substation.
[2] Proposed customer-scale renewables spread evenly across the existing customer-scale locations.
[3] Proposed utility-scale renewables served by the existing transmission (2-10 MW installations) or new dedicated feeders at the Frank Sound Substation (4 MW) and Prospect Substation (6.5 MW) and the remaining distributed as customer-scale DG system-wide.

1.5.1 Other Considerations

The analysis did not include scenarios involving a proposed Ocean Thermal Energy Conversion power plant (OTEC) that has requested interconnection on CUC's 69 kV Line L41 nor Battery Energy Storage Systems (BESSs). These scenarios were additional sensitivities that would require a more in-depth evaluation due to their complexities.

While the OTEC plant, as it is currently proposed (four 2.5 MW units), could simply serve as a substitute for a corresponding CUC unit, albeit with a slight degradation in system performance due to the plant's slower ramp response. Should the developer want to increase the plant's capability, a number of issues could arise that would need to be properly mitigated (refer to separate studies performed by Leidos). The incorporation of BESSs would require considerations such as, but not limited to: (1) location, (2) size, and (3) capability. A separate study would need to be performed to properly evaluate and determine the best use of BESSs on the CUC system.

1.6 Distribution Analysis Methodology

1.6.1 Power System Model

The distribution analysis was conducted using Milsoft's WindMil software package. The WindMil model was used to evaluate the electric system's performance considering peak and light load conditions in the normal system configuration. The flow cases were used to identify facilities that exhibit thermal (loading) or voltage violations, and whether these violations occur as a result of the additional renewable energy facilities or are pre-existing system conditions. The WindMil model was used to assess the impacts of various levels and placement of renewable generation.

Analysis results are based on the following data, assumptions, and criteria. Changes in these items will impact Study conclusions.

- The proposed Seven Mile Beach Substation and distribution feeders were added to the WindMil model for analysis. The substation is scheduled to be in-service in 2018.
- A new, dedicated feeder from Bodden Town Substation with 2 miles of 477 AAC overhead conductor was added to the WindMil model to serve the 5 MW Lakeview PV site, scheduled to be in-service in 2017.
- In the utility-scale renewable generation growth scenarios, new, dedicated feeders from Frank Sound and Prospect Substation was added to the model with 3.8 miles and 1.7 miles of 477 AAC overhead conductor, respectively.
- Each substation transformer was included in the model with the distribution bus regulated to 120 volts on a 120-volt base.
- The set point for each line regulator included in the model was set to regulate the output to 120 volts on a 120-volt base, with the exception of the regulator on Frank Sound Feeder 30 which was set at 123 volts.
- Load allocation in the updated WindMil model for the system minimum and peak was based on consumer energy usage.
- Customer-scale and utility-scale PV were added to the WindMil model as negative spot loads.
- ANSI Standard C84.1 was used as a basis for evaluating system voltages, limiting the range of voltages on the primary 13 kV distribution system to 126 V – 118 V (on a 120 V base).
- Conductor and equipment loading was limited to 100% of the rated capacity. Actual planning and operating practices for CUC could be lowered to maintain reserves for system contingencies.

- Load flows were performed using balanced analysis, which assumes CUC will address feeder imbalance issues created from the addition of renewables on the system.
- The allocation of the daytime peaks to the distribution feeders that was used in the study are shown in Table 1-3.

Table 1-3
Daytime Existing System Loads

Substation	Feeder	Peak[1] (MW)	Off-Peak[1] (MW)	PF
Bodden Town	15	7.43	5.20	0.940
	16	1.83	1.28	0.949
Frank Sound	30	3.43	2.40	0.960
	31	3.42	2.39	0.940
South Sound	20	2.18	1.52	0.910
	21	5.76	4.03	0.920
	22	3.70	2.59	0.940
	23	2.69	1.88	0.950
North Sound	2,6,7,9,10	17.02	11.92	0.941
	1,3,4,5,8	11.62	8.13	0.957
Rum Point	50	1.14	0.80	0.900
Hydesville	40	1.53	1.07	0.949
	41	4.65	3.25	0.920
	42	5.81	4.06	0.950
	43	5.75	4.03	0.900
Prospect	61	5.56	3.89	0.950
	62	5.48	3.84	0.950
Seven Mile Beach[2]	71	0.08	0.05	1.000
	72	3.69	2.58	0.956
	73	6.93	4.85	0.949
	74	0.31	0.22	0.933
TOTAL CUSTOMER LOAD		**100.00**	**70.00**	**0.942**

Notes:
[1] Loads shown are gross load (no PV included).
[2] The proposed in-service date for Seven Mile Beach is scheduled for 2018.

1.6.2 Voltage Flicker

Specific locations for larger, utility scale renewable generation as well as distributed renewable generation were modeled in WindMil. Load flows were prepared at various renewable generation scenarios to determine the steady-state voltages across the system at daytime peak and light loads. The renewable generation was then removed for each scenario to simulate losing the total renewable generation instantaneously. The resulting voltage rise/drop from the loss of the PV was compared to Figure 10-3 from IEEE Std 519-1992 and IEEE Std 1453-2004, shown below in Figure 1-2 below, to indicate if the voltage flicker would be visible or irritating.

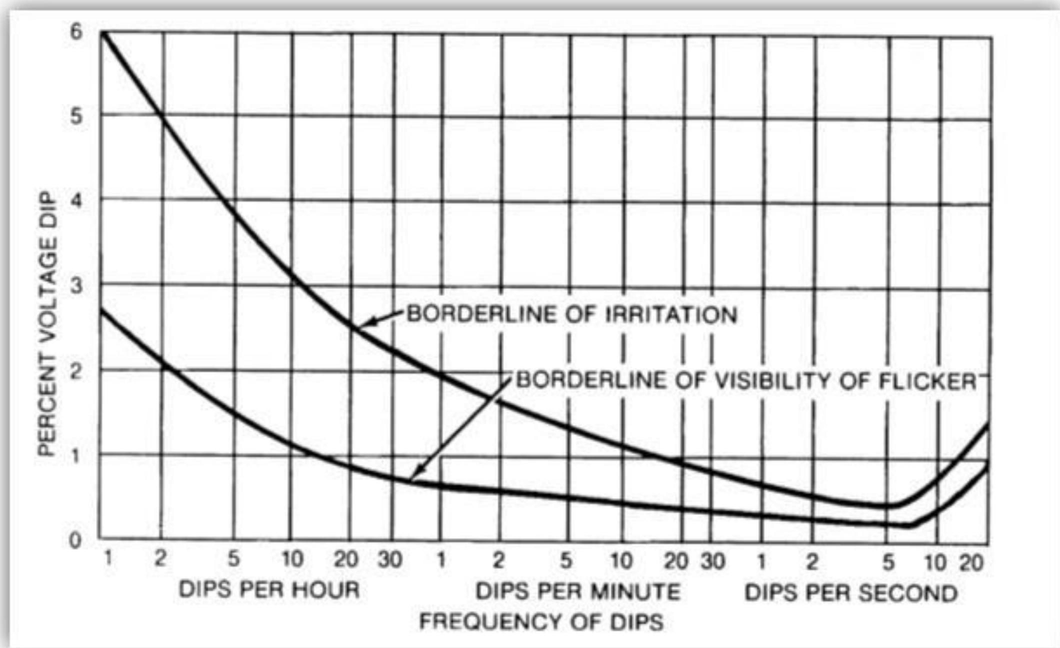

Figure 1-2. Voltage Flicker Chart

1.6.3 Short Circuit Analysis

Fault current contribution from the maximum level of PV studied was estimated, based on an industry-wide assumption, to be 120% of the continuous current rating of the total renewable generation.

1.6.4 Harmonic Injection

Leidos recommends CUC use monitoring devices and capture existing system harmonics to develop a baseline measurement for the system. Harmonic contribution will be inverter specific. Leidos represented the PV in this study with generic PV models, which would not accurately calculate specific induced harmonics and voltages from each site.

PV resources that are IEEE 1547 certified are limited to a reduced level of harmonic contribution for each order. By requiring the PV to be certified, CUC will limit the harmonic injection from each project to satisfactory levels on the system. No analysis will be required.

1.7 Transmission Analysis Methodology

1.7.1 Power System Model

The transmission analysis was conducted using power system models of the CUC system in the Siemens PTI's PSS®E (PSS/E) software package. Leidos developed the PSS/E model for the CUC system in 2009, which was updated for the dynamic stability analysis in this Study. The model revisions include updating the CUC 69 kV transmission line impedances to account for submarine cable charging and updates to the customer loads based on the latest load data provided to Leidos for this Study.

Generation Dispatch & Spinning Reserve Margin

Table 1-4 shows the generation dispatches that were evaluated for the transmission analysis. As described previously in Section 1, the intent was to create dispatches that either represent currently used dispatch practices or dispatches that CUC would consider exploring in order to maximize the amount of renewables. The true economic impact of the generation dispatches was not analyzed.

Generally, it is CUC practice to maintain approximately 18MW of spinning reserve to plan for the potential loss of their largest generator or substation transformer load. For the purposes of this analysis, however, the spinning reserve requirement was determined by the generator with the largest dispatch. The spinning reserve determined for each evaluated scenario was large enough to cover both the largest dispatched generating unit and the loss of the largest substation transformer load.

Table 1-4
Modeled Generation Dispatch

Unit ID	Description	Total Capacity (MW)	Peak Baseline (MW)	Peak Scenario 1 (MW)	Peak Scenario 3 (MW)	Off-Peak Baseline (MW)	Off-Peak Scenario 1 (MW)	Off-Peak Scenario 3 (MW)
CUC Generation								
1	Mak 8M601C	9.0	-	-	-	-	-	-
19	Caterpillar 3616	4.0	-	-	-	2.9	-	-
2	Mak 8M601C	9.0	8.0	7.7	5.9	-	-	-
20	Caterpillar 3616	4.0	-	-	-	-	-	-
26	MAN Gas Turbine	8.4	-	-	-	-	-	-
3	Caterpillar 3616	4.4	-	-	-	-	-	-
4	Caterpillar 3616	4.4	-	-	-	-	-	-
25	Solar Center 50 G. Turbine	3.5	-	-	-	-	-	-
34	Man B&W 12V 48/60	12.3	9.9	9.8	8.0	-	-	-
35	Man B&W 12V 48/60	12.3	9.9	9.8	8.0	-	-	-
36	Man B&W 12V 48/60	12.3	9.9	9.8	8.0	9.3	9.3	-
31	Man B&W 14V 48/60	18.0	15.0	14.4	11.7	13.3	13.6	11.4
32	Man B&W 14V 48/60	16.0	13.2	12.8	10.4	12.3	12.2	10.5
33	Man B&W 14V 48/60	16.0	13.2	12.8	10.4	12.3	12.2	10.5
30	Man B&W 14V 48/60	18.0	15.0	14.4	11.7	13.3	13.6	11.4
	TOTAL	**151.5**	**94.0**	**91.5**	**74.2**	**63.4**	**60.9**	**43.9**
Renewables								
Existing Renewables								
-	Lakeview Solar		5.0	5.0	5.0	5.0	5.0	5.0
-	Distributed Solar [1]		4.0	4.0	4.0	4.0	4.0	4.0
Future Renewables								
-	Frank Sound Solar		-	2.5	10.0	-	2.5	10.0
-	FS-30 & FS-31 'East End' Solar		-	-	10.0	-	-	10.0
	TOTAL		**9.0**	**11.5**	**29.0**	**9.0**	**11.5**	**29.0**
TOTAL OPERATING			**103.0**	**103.0**	**103.2**	**72.4**	**72.4**	**72.9**
Spinning Reserve			*16.7*	*18.6*	*33.3*	*16.1*	*14.9*	*17.5*
Reserve Requirement [2]			*15.0*	*14.4*	*11.7*	*13.3*	*13.6*	*11.4*

Notes:
[1] Distributed Solar netted from Customer Load.
[2] Reserve Requirement is based on the capacity of the largest operating unit.

Customer Load Modeling

As mentioned previously, there were two load conditions evaluated per this analysis: (1) daytime peak load and (2) daytime off-peak load. The load allocations for the transmission analysis are summarized in Table 1-5.

Table 1-5
Modeled Load Allocation

		Peak		Off-Peak		
Substation	Feeder	MW	PV Adj [1] MW	MW	PV Adj [1] MW	PF
Bodden Town	15	7.43	7.28	5.20	5.05	0.940
	16	1.83	1.78	1.28	1.24	0.949
Frank Sound	30	3.43	3.34	2.40	2.31	0.960
	31	3.42	3.39	2.39	2.37	0.940
South Sound	20	2.18	2.18	1.52	1.52	0.910
	21	5.76	5.47	4.03	3.74	0.920
	22	3.70	3.53	2.59	2.43	0.940
	23	2.69	2.69	1.88	1.88	0.950
North Sound	2,6,7,9,10	17.02	16.69	11.92	11.59	0.941
	1,3,4,5,8	11.62	10.54	8.13	7.05	0.957
Rum Point	50	1.14	1.11	0.80	0.77	0.900
Hydesville	40	1.53	1.50	1.07	1.04	0.949
	41	4.65	4.61	3.25	3.22	0.920
	42	5.81	5.71	4.06	3.97	0.950
	43	5.75	5.46	4.03	3.73	0.900
Prospect	61	5.56	5.20	3.89	3.53	0.950
	62	5.48	5.33	3.84	3.68	0.950
Seven Mile Beach	71	0.08	-0.18	0.05	-0.20	1.000
	72	3.69	3.66	2.58	2.55	0.956
	73	6.93	6.55	4.85	4.47	0.949
	74	0.31	0.16	0.22	0.07	0.933
TOTAL CUSTOMER LOAD		**100.00**	**96.00**	**70.00**	**66.00**	**0.942**
Generation Auxiliary Load		*1.7*	*1.7*	*1.7*	*1.7*	
System Losses		*1.3*	*1.3*	*0.7*	*0.7*	
TOTAL SYSTEM LOAD		**103.00**	**99.00**	**72.40**	**68.40**	

Note: [1] Adjusted to account for 4MW of existing rooftop distributed generation.

1.7.2 Renewable Generation Modeling

Steady-State Representation

The steady-state representation and capability of the renewable generation were based on typical manufacturing characteristics. Since it is impractical and unnecessary to model the entire plant collector system in detail, the renewable generation was represented by an aggregated model consisting of one or more equivalent generators, unit transformers, and collector systems at each plant's electric system connection point.

The PV is assumed to be capable of a leading/lagging 95% power factor. However, for purposes of this analysis, the regulating capability of the inverters was removed and the reactive capability of the renewable generation was set to 0 MVAR.

Dynamic Stability Representation

The dynamic modeling representation for the renewable generation was based on recommendations outlined by Western Electricity Coordinating Council (WECC) Modeling and Validation Work Group's PV Power Plant Dynamic Modeling Guide. The following generic PSS/E models were utilized with parameters as provided by WECC and detailed in Appendix B:

- REGCAU1 | Renewable Energy Generator/Converter Model
- REECBU1 | Generic Electric Control Model
- REPCAU1 | Generic Renewable Plant Control Model

Disturbance Ride-Through Criteria

Renewable generation is sensitive to sympathetic tripping due to common disturbance events on the transmission system. For this reason, CUC requires all generation to remain online – or ride-through (RT) – prior, during and after these disturbance conditions. The following criteria in Table 1-6 outlines the recommended boundary requirements the renewables will be required to stay online within, based on discussions with CUC and protective relay operation times.

Table 1-6
CUC Ride-Through Criteria

Range	Trip Time
Voltage Criteria	
$V_{bus} \leq 0.75$pu	Generator may initiate trip if voltage at POI remains in this range for more than 0.70 seconds
0.75pu $\leq V_{bus} \leq$ 0.80pu	Generator may initiate trip if voltage at POI remains in this range for more than 2.00 seconds
0.80pu $\leq V_{bus} \leq$ 0..88pu	Generator may initiate trip if voltage at POI remains in this range for more than 5.00 seconds
0.88pu $\leq V_{bus} \leq$ 1.1pu	Continuous Operation
1.1pu $\leq V_{bus} \leq$ 1.15pu	Generator may initiate trip if voltage at POI remains in this range for more than 1.00 seconds
1.15pu $\leq V_{bus} \leq$ 1.20pu	Generator may initiate trip if voltage at POI remains in this range for more than 0.5 seconds
1.20pu $\leq V_{bus}$	Generator may initiate trip if voltage at POI remains in this range for more than 0.20 seconds
Frequency Criteria	
$F_{bus} \leq$ 55.0Hz	Instantaneous trip
55.0Hz $\leq F_{bus} \leq$ 56.6Hz	Generator may initiate trip if voltage at POI remains in this range for more than 1.00 seconds
56.7Hz $\leq F_{bus} \leq$ 62.9Hz	Continuous Operation
63.0Hz $\leq F_{bus} \leq$ 65.0Hz	Generator may initiate trip if voltage at POI remains in this range for more than 1.00 seconds
65.0Hz $\leq F_{bus}$	Instantaneous trip

1.7.3 Protection Modeling

CUC has an Under Frequency Load Shedding scheme (UFLS) to assist with system reliability and protection. The UFLS will reduce load in specified blocks should the frequency experienced by the relay violate a specified limit for an unacceptable duration. The scheme utilized for this analysis is summarized in Table 1-7.

Table 1-7
Under Frequency Load Shed Scheme

Substation	Feeder	Relay	UF Setting Hz	UF Setting Timing (s)	% of Total Load
Bodden Town	BT-15	NOVA	55.5	3.0	7.4%
	BT-16	NOVA	58.7	4.0	1.8%
Frank Sound	FR-30	ABB-DPU	57.5	3.5	3.4%
	FR-31	ABB-DPU	56.0	3.5	3.4%
South Sound	SS-20	ABB-DPU	57.5	2.5	2.2%
	SS-21	ABB-DPU	56.5	2.5	5.8%
	SS-22	ABB-DPU	56.5/56.0	4.50/1.75	3.7%
	SS-23	ABB-DPU	56.5/56.0	4.00/3.00	2.7%
North Sound	NS-01	Woodward MFR13 #5	56.5	3.5	1.7%
	NS-02	Woodward MFR13 #1	54.5	1.0	4.8%
	NS-03	Woodward MFR13 #3	57.5	5.0	3.4%
	NS-04	Woodward MFR13 #4	55.5	1.5	5.5%
	NS-05	Woodward MFR13 #4	55.5	2.0	3.6%
	NS-06	Woodward MFR13 #2	58.5	3.0	0.6%
	NS-07	Woodward MFR13 #1	54.5	1.5	5.1%
	NS-08	Woodward MFR13 #5	58.5	5.0	2.7%
	NS-09	Woodward MFR13 #2	56.5	3.0	0.9%
	NS-10	Woodward MFR13 #3	58.5	3.5	0.2%
Rum Point	RP-50	GEC-MFVU 14	56.0	4.0	1.1%
Hydesville	HD-40	ABB-DPU	56.0	2.5	1.5%
	HD-41	ABB-DPU	57.5	3.0	4.6%
	HD-42	ABB-DPU	57.5	4.0	5.8%
	HD-43	ABB-DPU	56.5	2.0	5.8%
Prospect	PR-61		56.5	4.5	5.6%
	PR-62		56.5	4.5	5.5%
Seven Mile Beach	SMB-71		58.5	3.5	0.1%
	SMB-72		58.5	3.5	3.7%
	SMB-73		55.5	2.0	6.9%
	SMB-74		55.5	2.0	0.3%

For purposes of this analysis, generation rotor speed was monitored for speeds greater than 108% (1944 RPMs). Should a generator exceed this speed, it will be tripped offline.

1.7.4 Dynamic Stability Analysis

The transmission analysis consisted of simulating disturbance events and analyzing the dynamic response of CUC's electric system. The specific events studied are summarized in Table 1-8 and detailed in Appendix C. Events included transmission line faults with primary relay failure at locations throughout the 69 kV system, distribution bus/feeder faults with loss of load, and loss of the largest generator in the system, with and without a fault. Various system characteristics, including bus voltages, transmission line flow, generator rotor angles, and other indicators of system stability, were monitored during the simulations and plotted over a time frame of twenty (20) seconds.

Table 1-8
Stability Disturbance Event Descriptions

Sim No.	Simulation Filename	Disturbance Description
1	sim_01_3ph_BT-FS-69kV	3-Phase Fault on Bodden Town to Frank Sound 69-kV Line; Bodden Town end; Primary relay failure
2	sim_02_3ph_BT-PR-69kV	3-Phase Fault on Bodden Town to Prospect 69-kV Line; Bodden Town end; Primary relay failure
3	sim_03_3ph_SS-PR-69kV	3-Phase Fault on South Sound to Prospect 69-kV Line; South Sound end; Primary relay failure
4	sim_04_3ph_SS-NS-69kV	3-Phase Fault on South Sound to North Sound 69-kV Line; South Sound end; Primary relay failure
5	sim_05_3ph_NS-RP-69kV	3-Phase Fault on North Sound to Rum Point 69-kV Line; North Sound end; Primary relay failure
6	sim_06_3ph_RP-FS-69kV	3-Phase Fault on Rum Point to Frank Sound 69-kV Line; Rum Point end; Primary relay failure
7	sim_07_3ph_HY-SMB-69kV	3-Phase Fault on Hydesville to Seven Mile Beach 69-kV Line #1; Hydesville end; Primary relay failure
8	sim_08_3ph_SMB-NS-69kV	3-Phase Fault on Seven Mile Beach to North Sound 69-kV Line #1; Seven Mile Beach end; Primary relay failure
9	sim_09_3ph_HY-NS2-69kV	3-Phase Fault on Hydesville to North Sound 69-kV Line #2; Hydesville end; Primary relay failure
10	sim_10_3ph_LossGen_Unit30	3-Phase Fault at North Sound 69-kV substation; Normal Clearing; Loss of Largest Generator (Unit 30)
11	sim_11_LossGen_Unit30	Loss of Largest Generator (Unit 30) | No Fault
12	sim_12_3ph_LVIEW-13kV	3-Phase Fault at Bodden Town 13-kV substation; Normal Clearing; Loss of Lakeview PV
13	sim_13_3ph_FSPV-13kV	3-Phase Fault at Frank Sound 13-kV substation; Normal Clearing; Loss of Frand Sound PV
14	sim_14_3ph_FS30-13kV	3-Phase Fault at Frank Sound 13-kV substation; Normal Clearing; Loss of Feeder FS-30
15	sim_15_3ph_FS31-13kV	3-Phase Fault at Frank Sound 13-kV substation; Normal Clearing; Loss of Feeder FS-31
16	sim_16_3ph_All-FSPV-13kV	3-Phase Fault at Frank Sound 13-kV substation; Normal Clearing; Loss of all Frank Sound PV

Performance Monitoring Criteria

For purposes of this analysis, a stable disturbance event response requires the electric system to remain online and functioning while having an acceptable generation damping response. Additionally, post-transient criteria, as seen in Table 1-9, was evaluated against the system's disturbance response to determine if it is both stable and acceptable. Violations to the criteria could lead to additional analysis and recommendations in order to mitigate them; however, ancillary facility responses, such as load shedding and generation tripping due to protection schemes, will be identified but considered acceptable as part of the system's disturbance event response.

Table 1-9
Stability Performance Monitoring Criteria

Post-Transient Voltage Deviation Limits (20+ seconds)	Post-Transient Facility Seasonal Loading Limits (20+ seconds)
$0.9pu \leq V_{bus} \leq 1.1pu$	Line_Loading ≤ (1.0)(Rate B) Xfmr_Loading ≤ (1.1)(Rate B)

2.1 Steady-State Power Flow Results

The Renewable Infusion Study analyzed increased levels of PV penetration for the normal system configuration, with Seven Mile Beach Substation in service. The existing load and renewable generation assumptions used in the analysis are described in Section 1. As explained in Section 1, peak and light load scenarios were evaluated with increasing levels of PV penetration. This section summarizes the results of the steady-state analysis on the distribution system.

2.1.1 Available Capacity for Renewables

Each feeder was evaluated to determine the available capacity to add renewables without reverse flow on the feeder breaker, while still maintaining voltage within the existing system operating practices and avoiding voltage flicker on the feeder. The limits determined from the evaluation will be used in the steady-state and voltage flicker analysis on the distribution system. It was assumed that the proposed additions of customer-scale renewables used in the evaluations would be proportional to the existing installed DG and applications, and dedicated distribution feeders would be added to the Frank Sound and Prospect substations to connect utility-scale installations. However, alternative scenarios within the identified maximum available capacities for feeder and transformer limits would be permissible. A summary of the analysis is given in Table 2-1 below.

The evaluation of the available renewable capacity indicated the following:

- The capacity of the existing transmission and distribution infrastructure to serve RE without causing reverse flow, capacity or system voltage issues significantly exceeds the system limitation of 29 MW.
- The 5 MW Lakeview solar farm would cause reverse flow on the Bodden Town transformer at the off–peak load evaluated. No additional renewables were included on the Bodden Town transformer in the remaining analysis.
- CUC has (4) 1.5 MW mobile Caterpillar generating units installed near the North Sound Plant on Feeder 7. The units cause reverse flow on Feeder 7 at the off–peak load evaluated. No additional renewables were included on Feeder 7 in the remaining analysis.
- It was assumed that dedicated distribution feeders would be added to the Frank Sound and Prospect substations to serve future utility-scale renewable installations on the east end of the island. However, the future utility-scale capacity is limited such that reverse flow on the substation transformers and distribution feeders is prevented.

2.1.2 Feeder Capacity & Voltage

Based on the limits presented in Table 2-1, each feeder was evaluated to determine if capacity or voltage criteria would be exceeded with the proposed renewables for each scenario. A summary of the analysis is given in Table 2-2 through Table 2-5.

This evaluation indicated the following:

- No significant impact on feeder capacity or voltage at peak or off-peak loading conditions was noted with the addition of renewables for the maximum customer-scale or utility scale scenarios defined in Table 2-1.
- Distribution losses are improved as the customer-scale renewables are maximized versus utility-scale renewables.

Table 2-1
Available Feeder Capacity for Additional Renewables

Substation	Feeder	Total Installed DG & Applicants (kW)	Off-Peak Feeder Load (kW)		Off-Peak Transformer Load (kW)		Available Capacity to Add DG w/o Reverse Flow			Total DG Max Customer-Scale Scenario		Total DG Max Utility-Scale Scenario	
			Without Installed DG & Applicants	With Installed DG & Applicants	Without Installed DG & Applicants	With Installed DG & Applicants	To Feeder (kW)	To Transformer (kW)	Max V%	11.5MW	29MW	11.5MW	29MW
Bodden Town	G1	5,000	0	-4,928	4,770	-304	0	4,770	N/A	5,000.0	5,000.0	5,000.0	5,000.0
	15	156	4,761	4,623			4,761		98.7	156.0	156.0	156.0	156.0
	16	45	1,170	1,125	1,171	1,126	1,170	1,171	100.0	81.2	370.0	45.0	232.9
Frank Sound	30	88	2,209	2,123	4,395	4,284	2,209	4,395	100.0	158.7	723.6	88.0	310.4
	31	24	2,178	2,154			2,178		100.8	43.3	197.3	24.0	84.6
	32 [1]	0	0	0			0		N/A	0.0	0.0	2,500.0	4,000.0
South Sound	20	0	1,392	1,392	5,732	5,450	1,392	5,732	99.9	0.0	0.0	0.0	0.0
	21	288	4,327	4,045			4,327		100.9	519.5	2,368.1	288.0	1,490.7
	22	162	2,370	2,209	4,098	3,937	2,370	4,098	100.0	292.2	1,332.1	162.0	838.5
	23	0	1,722	1,722			1,722		100.4	0.0	0.0	0.0	0.0
North Sound	1	0	1,109	1,109	12,370	10,962	1,109	12,370	100.0	0.0	0.0	0.0	0.0
	2	346	3,078	2,734			3,078		100.9	624.1	2,845.1	346.0	1,790.9
	3	164	2,201	2,038			2,201		99.8	295.8	1,348.5	164.0	848.8
	4	79	3,552	3,473			3,552		100.3	142.5	649.6	79.0	408.9
	5	67	2,321	2,255			2,321		100.0	120.8	550.9	67.0	346.8
	6	269	397	129			397		100.0	397.4	397.4	269.0	397.4
	7	268	-2,710	-2,977			0		N/A	268.0	268.0	268.0	268.0
	8	21	1,738	1,718			1,738		100.0	37.9	172.7	21.0	108.7
	9	200	568	369			568		100.0	360.7	568.0	200.0	568.0
	10	0	114	114			114		100.0	0.0	0.0	0.0	0.0
Rum Point	50	26	727	701	727	701	727	730	99.5	46.9	213.8	26.0	134.6
Hydesville	40	32	963	932	11,231	10,758	963	11,231	100.0	57.7	263.1	32.0	165.6
	41	32	2,888	2,860			2,888		100.6	57.7	263.1	32.0	165.6
	42	98	3,631	3,539			3,631		101.5	176.8	805.8	98.0	507.2
	43	294	3,691	3,373			3,691		102.7	530.3	2,417.5	294.0	1,521.7
Prospect	61	361	3,567	3,218	7,074	6,570	3,567	7,074	101.1	651.1	2,968.4	361.0	400.0
	62	157	3,506	3,353			3,506		101.9	283.2	1,291.0	157.0	174.0
	63 [1]	0	0	0			0		101.9	0.0	0.0	0.0	6,500.0
Seven Mile Beach	71	258	49	-208	7,062	6,244	0	7,062	100.0	258.0	258.0	258.0	258.0
	72	27	2,365	2,339			2,365		100.8	48.7	222.0	27.0	139.7
	73	383	4,447	4,066			4,447		100.9	690.8	3,149.3	383.0	1,982.4
	74	153	201	47			201		100.0	200.6	200.6	153.0	200.6
TOTALS		**8,998**	**58,535**	**49,646**	**58,630**	**49,728**	**61,196**	**58,633**		**11,500.0**	**29,000.0**	**11,498.0**	**29,000.0**

Note: [1] Proposed new feeders dedicated to serve utility-scale DG.

Table 2-2
System Daytime Light Load Steady-State Analysis Summary: Customer-Scale Growth

Substation	Baseline PV = 9 MW (5MW Lakeview/4MW Customer Scale Distributed)							Scenario 2 PV = 11.5 MW (5MW Lakeview/6.5MW Customer Scale Distributed)							Scenario 4 PV = 29 MW (5MW at Lakeview/24MW Customer Scale Distributed)						
	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)
Seven Mile Beach	6,244.1	94.2	29.7	37.8	99.25	100.02	820.2	5,867.8	93.5	27.3	36.4	99.3	100.0	1,198.1	3,244.7	82.5	15.0	36.2	99.5	100.0	3,829.9
Bodden Town	822.3	34.0	99.3	42.9	97.30	99.86	5,201.8	787.2	32.8	99.2	42.9	97.3	99.9	5,237.2	500.1	21.6	98.2	42.9	97.3	99.9	5,526.0
Frank Sound	4,363.0	93.6	80.8	27.1	97.93	102.32	112.8	4,245.6	93.4	78.3	26.8	97.4	101.7	202.0	3,530.5	91.4	63.2	24.5	97.8	101.8	920.9
Hydesville	10,757.4	88.7	146.1	52.1	98.01	99.88	456.8	10,376.6	88.3	136.3	48.4	98.1	99.6	822.5	7,485.4	82.7	92.5	52.2	98.7	100.0	3,749.6
North Sound	10,962.0	96.2	97.9	46.2	98.72	100.22	1,413.4	10,131.2	95.6	94.7	46.2	98.7	100.2	2,247.3	5,596.5	87.5	81.0	50.3	98.8	100.2	6,800.2
Prospect	6,570.7	92.8	43.7	25.6	97.36	100.00	518.0	6,166.9	92.2	39.4	24.5	97.4	100.2	934.3	2,900.4	77.1	22.6	35.2	97.7	100.0	4,259.4
Rum Point	700.8	89.1	0.9	5.5	99.42	99.72	26.4	687.2	88.6	0.9	5.4	99.7	100.3	46.9	519.6	82.4	0.8	4.7	99.7	100.3	213.8
South Sound	9,388.0	91.0	67.8	38.1	98.46	100.17	450.7	9,048.9	90.4	63.5	36.5	98.8	100.5	811.7	6,148.3	83.4	37.9	23.2	98.9	100.2	3,700.2
TOTAL	**49,808**		**566**				**9,000**	**47,311**		**540**				**11,500**	**29,925**		**411**				**29,000**

Table 2-3
System Daytime Light Load Steady-State Analysis Summary: Utility-Scale Growth

Substation	Baseline PV = 9 MW (5MW Lakeview/4MW Customer Scale Distributed)							Scenario 1 DG = 11.5 MW (5MW Lakeview/4MW Customer Scale Distributed/2.5MW Utility Scale on Frank Sound Dedicated Feeder)							Scenario 3 PV = 29 MW (5MW Lakeview/13.5MW Customer Scale Distributed/4MW on Frank Sound Dedicated Feeder/6.5MW on Prospect Dedicated Feeder)						
	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)
Seven Mile Beach	6,244.1	94.2	29.7	37.8	99.25	100.02	820.2	6,244.0	94.2	29.7	37.8	99.3	100.0	820.2	4,490.7	89.6	19.3	30.7	99.5	100.0	2,580.7
Bodden Town	822.3	34.0	99.3	42.9	97.30	99.86	5,201.8	822.3	34.0	99.3	42.9	97.3	99.9	5,201.8	636.5	27.0	98.6	42.9	97.3	99.9	5,388.9
Frank Sound	4,363.0	93.6	80.8	27.1	97.93	102.32	112.8	1,824.1	75.9	102.8	26.9	97.4	101.8	2,612.8	49.3	3.0	139.9	28.0	97.6	101.8	4,395.0
Hydesville	10,757.4	88.7	146.1	52.1	98.01	99.88	456.8	10,757.6	88.7	146.1	52.1	98.0	99.9	456.8	8,854.2	86.0	106.8	43.8	98.5	99.8	2,360.2
North Sound	10,962.0	96.2	97.9	46.2	98.72	100.22	1,413.4	10,962.0	96.2	97.9	46.2	98.7	100.2	1,413.4	7,652.1	92.7	85.1	46.2	98.8	100.2	4,737.5
Prospect	6,570.7	92.8	43.7	25.6	97.36	100.00	518.0	6,570.5	92.8	43.7	25.6	97.4	100.0	518.0	123.3	4.9	135.9	45.1	97.3	100.2	7,074.0
Rum Point	700.8	89.1	0.9	5.5	99.42	99.72	26.4	700.8	89.1	0.9	5.5	99.4	99.7	26.4	599.1	85.8	0.8	4.9	99.7	100.3	134.6
South Sound	9,388.0	91.0	67.8	38.1	98.46	100.17	450.7	9,387.4	91.0	67.8	38.1	98.5	100.2	450.7	7,502.8	87.6	47.1	29.1	98.8	100.2	2,329.1
TOTAL	**49,808**		**566**				**9,000**	**47,269**		**588**				**11,500**	**29,908**		**633**				**29,000**

Table 2-4
System Daytime Peak Load Steady-State Analysis Summary: Customer Scale Growth

Substation	Baseline PV = 9 MW (5MW Lakeview/4MW Customer Scale Distributed)						
	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)
Seven Mile Beach	9,214.3	94.7	61.6	54.3	98.9	100.0	820.2
Bodden Town	3,427.5	72.6	142.8	62.2	96.1	100.0	5,201.8
Frank Sound	6,251.1	93.3	158.7	37.3	95.6	101.7	112.8
Hydesville	15,554.9	87.1	309.6	76.7	97.0	100.1	456.8
North Sound	18,846.3	95.8	196.1	46.2	98.2	100.2	1,413.4
Prospect	9,602.4	92.4	92.6	36.9	96.1	100.0	518.0
Rum Point	1,002.7	89.2	1.8	7.8	99.2	99.6	26.4
South Sound	13,586.7	90.6	142.4	55.4	97.5	100.2	450.7
TOTAL	**77,486**		**1,106**				**9,000**

Substation	Scenario 2 PV = 11.5 MW (5MW Lakeview/6.5MW Customer Scale Distributed)						
	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)
Seven Mile Beach	8,838.7	94.2	58.1	53.0	99.0	100.0	1,198.1
Bodden Town	3,392.3	72.3	142.5	62.2	96.1	100.0	5,237.2
Frank Sound	6,160.0	93.2	156.2	37.2	95.7	101.7	202.0
Hydesville	15,281.4	86.9	296.0	72.3	97.8	100.0	822.5
North Sound	18,017.1	95.5	191.3	46.2	98.2	100.2	2,247.3
Prospect	9,205.2	92.0	86.1	36.1	96.2	100.0	934.3
Rum Point	992.1	88.8	1.8	7.8	99.6	100.2	46.9
South Sound	13,258.4	90.2	136.2	53.8	98.2	100.1	811.7
TOTAL	**75,145**		**1,068**				**11,500**

Substation	Scenario 4 PV = 29 MW (5MW at Lakeview/24MW Customer Scale Distributed)						
	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)
Seven Mile Beach	6,221.8	89.3	36.7	42.1	99.3	100.0	3,829.9
Bodden Town	3,105.0	69.3	140.8	62.2	96.1	100.1	5,526.0
Frank Sound	5,438.8	92.0	133.5	35.0	96.1	101.8	920.9
Hydesville	12,306.8	84.0	213.3	60.9	98.0	100.1	3,749.6
North Sound	13,494.3	92.4	165.0	50.3	98.2	100.2	6,800.2
Prospect	5,972.4	85.9	50.8	34.9	96.5	100.0	4,259.4
Rum Point	824.9	85.1	1.7	6.7	99.6	100.2	213.8
South Sound	10,362.6	86.5	92.1	39.9	98.1	100.1	3,700.2
TOTAL	**57,727**		**834**				**29,000**

Table 2-5
System Daytime Peak Load Steady-State Analysis Summary: Utility Scale Growth

Substation	Baseline PV = 9 MW (5MW Lakeview/4MW Customer Scale Distributed)							Scenario 1 DG = 11.5 MW (5MW Lakeview/4MW Customer Scale Distributed/2.5MW Utility Scale on Frank Sound Dedicated Feeder)							Scenario 3 PV = 29 MW (5MW Lakeview/13.5MW Customer Scale Distributed/4 MW on Frank Sound Dedicated Feeder/6.5MW on Propect Dedicated Feeder)						
	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)	kW	PF (%)	Losses (kW)	Max % Loading	Min V (%)	Max V (%)	Total DG (kW)
Seven Mile Beach	9,214.3	94.7	61.6	54.3	98.9	100.0	820.2	9,214.3	94.7	61.6	54.3	98.9	100.0	820.2	7,464.8	92.2	45.4	47.2	99.1	100.0	2,580.7
Bodden Town	3,427.5	72.6	142.8	62.2	96.1	100.0	5,201.8	3,427.4	72.6	142.7	62.2	96.1	100.0	5,201.8	3,241.5	70.8	141.5	62.2	96.1	100.1	5,388.9
Frank Sound	6,251.1	93.3	158.7	37.3	95.6	101.7	112.8	3,730.8	85.4	177.8	37.3	95.8	101.8	2,612.8	1,950.4	65.0	210.3	36.6	96.0	101.8	4,395.0
Hydesville	15,554.9	87.1	309.6	76.7	97.0	100.1	456.8	15,554.7	87.1	309.6	76.7	97.0	100.1	456.8	13,659.5	85.6	244.8	60.8	97.7	99.6	2,360.2
North Sound	18,846.3	95.8	196.1	46.2	98.2	100.2	1,413.4	18,846.3	95.8	196.1	46.2	98.2	100.2	1,413.4	15,544.2	94.1	175.0	46.2	98.2	100.2	4,737.5
Prospect	9,602.4	92.4	92.6	36.9	96.1	100.0	518.0	9,602.4	92.4	92.6	36.9	96.1	100.0	518.0	3,234.2	66.6	183.8	45.0	96.2	100.0	7,074.0
Rum Point	1,002.7	89.2	1.8	7.8	99.2	99.6	26.4	1,002.7	89.2	1.8	7.8	99.2	99.6	26.4	904.3	87.1	1.7	7.2	99.6	100.2	134.6
South Sound	13,586.7	90.6	142.4	55.4	97.5	100.2	450.7	13,586.8	90.6	142.4	55.4	97.5	100.2	450.7	11,704.2	88.6	109.9	46.3	97.9	100.1	2,329.1
TOTAL	**77,486**		**1,106**				**9,000**	**74,965**		**1,125**				**11,500**	**57,703**		**1,112**				**29,000**

2.2 Voltage Flicker Results

Scenarios 1-4 studied in distribution steady-state analysis were also evaluated for voltage flicker implications at both peak and light loads. For each scenario, the renewable generation was removed to simulate losing the renewable generation instantaneously. The resulting voltage rise/drop with the loss of the renewable generation compared to the voltage with renewable generation was applied to Figure 10-3 from IEEE Standard 519 to determine if the voltage flicker would be visible or irritating at this extreme condition.

While, in reality, the loss of total system renewable generation simultaneously is not expected to occur, the evaluation confirms if voltage flicker levels could be greater than the line of visibility for existing system customers in just one event. If yes, then a more in-depth analysis, including variability of the renewable generation over time due to cloud cover, could be necessary to gain a better understanding of the likelihood of voltage flicker issues.

Tables 2-6 and 2-7 displays the flicker analysis results by showing the maximum voltage percent change for each substation for each scenario. Excluding Frank Sound and Hydesville Substations, the maximum calculated voltage flicker falls below the line of visibility and well below the line of irritation in the voltage flicker chart shown in Figure 1-1.

Based on the analysis, a maximum voltage flicker of 2.42% was identified on the Hydesville Substation feeders for daytime peak load and 2.27% daytime light load Scenario 4. However, these values are below the visibility threshold for one operation per hour as shown in Figure 1-1.

Table 2-6
Voltage Flicker Analysis Summary – Daytime Peak Load

Substation	Scenario 2 Customer-Scale	Scenario 4 Customer-Scale	Scenario 1 Utility-Scale	Scenario 3 Utility-Scale
	Max % Voltage Change (11.5 MW)	Max % Voltage Change (29 MW)	Max % Voltage Change (11.5 MW)	Max % Voltage Change (29 MW)
Seven Mile Beach	0.12	0.52	0.06	0.33
Bodden Town	1.42	1.42	1.42	1.42
Frank Sound	0.13	0.60	1.21	1.87
Hydesville	0.56	2.42	0.31	1.56
North Sound	0.11	0.50	0.11	0.32
Prospect	0.29	1.28	0.16	1.49
Rum Point	0.01	0.03	0.00	0.02
South Sound	0.24	1.04	0.13	0.67

Table 2-7
Voltage Flicker Analysis Summary – Daytime Light Load

Substation	Scenario 2 Customer-Scale	Scenario 4 Customer-Scale	Scenario 1 Utility Scale	Scenario 3 Utility Scale
	Max % Voltage Change (11.5 MW)	Max % Voltage Change (29 MW)	Max % Voltage Change (11.5 MW)	Max % Voltage Change (29 MW)
Seven Mile Beach	0.12	0.52	0.06	0.33
Bodden Town	1.36	1.36	1.36	1.36
Frank Sound	0.13	0.58	1.18	1.83
Hydesville	0.52	2.27	0.29	1.45
North Sound	0.11	0.50	0.11	0.32
Prospect	0.28	1.20	0.15	1.40
Rum Point	0.01	0.03	0.00	0.02
South Sound	0.22	1.00	0.13	0.64

2.3 Short Circuit and Protection Evaluation Results

A general rule of thumb is that fault contribution from PV sources can be up to 120% of the rated capacity of the inverters. Using this assumption, only 161 amps/phase of fault current would be added to the 13 kV distribution system if the PV threshold of 29 MW was installed at a single location. Based on typical system protective devices and schemes, the additional fault contribution from the anticipated customer-based renewable generation sources dispersed across the system would have a negligible impact on the overcurrent device duty ratings and coordination. Line devices (such as fuses, reclosers, sectionalizers, etc.) may need to be evaluated individually for larger renewable generation installations, and be modified for reverse flow capability.

2.4 Results Summary

The following summarizes the findings from the distribution level analysis, including steady state load flows, voltage flicker, and short circuit analysis:

- Renewable penetration on the existing substation transformers and distribution feeders can exceed the limits determined based on the existing generation and dispatch without causing reverse flow, feeder capacity or system voltage issues.
- No additional renewables can be added to the Bodden Town transformer without causing reverse flow with the addition of the 5 MW Lakeview solar farm.
- No additional renewables can be added to Feeder 7 out of the North Sound Plant without causing reverse flow with the existing (4) 1.5 MW mobile Caterpillar generating units on-line.

- Future utility-scale installations on the east end of the island can be added the Frank Sound and Prospect substations; however, the total capacity should be limited such that reverse flow on the substation transformers and distribution feeders is prevented.
- Distribution losses are improved when customer-scale renewables are maximized versus utility-scale renewables.
- The additional fault contribution from the proposed renewables dispersed across the system would have a negligible impact on the overcurrent device duty ratings and coordination, although line devices (such as fuses, reclosers, sectionalizers, etc.) may need to be evaluated individually for larger renewable generation installations, and be modified for reverse flow capability.

Section 3
TRANSMISSION ANALYSIS RESULTS

3.1 Stability Analysis Results

Presented within this section are the results of the dynamic stability analysis that assessed the response of CUC's electric transmission system to the addition of various injections of renewable generation options. The options were evaluated considering the scenarios maximizing the utility-scale interconnections, or Scenarios 1 & 3. Leidos conducted disturbance event simulations on both the daytime off-peak and daytime peak load scenarios.

Tables 3-1 and 3-2 provide summaries of the CUC system performance responses for each of the renewable option scenarios while considering the ride-through and protection criteria as described in Section 1. More detailed result summaries and plots are in Appendices D and E, respectively.

Table 3-1
Stability Event Summary | Off-Peak

Sim No.	Simulation Filename	Baseline	Scenario 1 (Utility-Scale)	Scenario 3 (Utility-Scale)
1	sim_01_3ph_BT-FS-69kV	- Stable Response	- Stable Response	- Stable Response
2	sim_02_3ph_BT-PR-69kV	- Stable Response	- Stable Response	- Stable Response
3	sim_03_3ph_SS-PR-69kV	- Stable Response	- Stable Response	- Stable Response
4	sim_04_3ph_SS-NS-69kV	- Stable Response	- Stable Response	- Stable Response
5	sim_05_3ph_NS-RP-69kV	- Stable Response	- Stable Response	- Stable Response
6	sim_06_3ph_RP-FS-69kV	- Stable Response	- Stable Response	- Stable Response
7	sim_07_3ph_HY-SMB-69kV	- Stable Response	- Stable Response	- Stable Response
8	sim_08_3ph_SMB-NS-69kV	- Stable Response	- Stable Response	- Stable Response
9	sim_09_3ph_HY-NS2-69kV	- Stable Response	- Stable Response	- Stable Response
10	sim_10_3ph_LossGen_Unit30	- Stable Response	- Stable Response	- Stable Response
11	sim_11_LossGen_Unit30	- Stable Response	- Stable Response	- Stable Response
12	sim_12_3ph_LVIEW-13kV	- Stable Response	- Stable Response	- Stable Response
13	sim_13_3ph_FSPV-13kV	- Not Applicable	- Stable Response	- Stable Response
14	sim_14_3ph_FS30-13kV	- Not Applicable	- Not Applicable	- Stable Response
15	sim_15_3ph_FS31-13kV	- Not Applicable	- Not Applicable	- Stable Response
16	sim_16_3ph_All-FSPV-13kV	- Not Applicable	- Stable Response	- Stable Response

Table 3-2
Stability Event Summary | Peak

Sim No.	Simulation Filename	Baseline	Scenario 1 (Utility-Scale)	Scenario 3 (Utility-Scale)
1	sim_01_3ph_BT-FS-69kV	- Stable Response	- Stable Response	- Stable Response
2	sim_02_3ph_BT-PR-69kV	- Stable Response	- Stable Response	- Stable Response
3	sim_03_3ph_SS-PR-69kV	- Stable Response	- Stable Response	- Stable Response
4	sim_04_3ph_SS-NS-69kV	- Stable Response	- Stable Response	- Stable Response
5	sim_05_3ph_NS-RP-69kV	- Stable Response	- Stable Response	- Stable Response
6	sim_06_3ph_RP-FS-69kV	- Stable Response	- Stable Response	- Stable Response
7	sim_07_3ph_HY-SMB-69kV	- Stable Response	- Stable Response	- Stable Response
8	sim_08_3ph_SMB-NS-69kV	- Stable Response	- Stable Response	- Stable Response
9	sim_09_3ph_HY-NS2-69kV	- Stable Response	- Stable Response	- Stable Response
10	sim_10_3ph_LossGen_Unit30	- Stable Response	- Stable Response	- Stable Response
11	sim_11_LossGen_Unit30	- Stable Response	- Stable Response	- Stable Response
12	sim_12_3ph_LVIEW-13kV	- Stable Response	- Stable Response	- Stable Response
13	sim_13_3ph_FSPV-13kV	- Not Applicable	- Stable Response	- Stable Response
14	sim_14_3ph_FS30-13kV	- Not Applicable	- Not Applicable	- Stable Response
15	sim_15_3ph_FS31-13kV	- Not Applicable	- Not Applicable	- Stable Response
16	sim_16_3ph_All-FSPV-13kV	- Not Applicable	- Stable Response	- Stable Response

The results show that the CUC system remained stable for the simulated disturbance events with no loss of customer load or CUC generation and no performance criteria violations. In general, the system response was better for Scenario 1 with 2.5 MW additional renewable generation than with 20 MW additional renewable generation in Scenarios 3, while neither option outperformed the Baseline. The renewables do not respond as effectively to the disturbance events when compared to the existing CUC generators.

3.2 Operating Reserve Considerations

As the penetration of variable generation increases on a power grid, the system operation strategy also needs to be reviewed and adjusted appropriately. While the output of a single solar PV facility is highly variable, the aggregate variability of distributed, customer-owned solar PV reduces significantly. It is difficult to quantify the aggregate variability of solar PV due to a cloud cover and probability of the occurrence. It is highly dependent on the geographical location, irradiance profile and the size and mix of installed PV. Therefore, the case studies conducted in the industry for such variability do not yield consistent results that could be used for making generic recommendations.

The operating philosophy of each utility could differ when it comes to maintaining additional operating reserve to account for the generation variability which is dependent on the weather pattern. It is a standard practice for a utility to carry sufficient spinning reserve to survive their most severe single contingency, often the largest generating unit. This spinning reserve falls into the category of contingency reserve. Whether a separate operating reserve should be set aside to manage variability of solar PV becomes an economic decision to a certain extent. The following observations and recommendations are provided to help manage higher penetration of variable distributed generation from the system operation standpoint:

- Customer-owned distributed generation systems will likely not peak simultaneously and will not produce at aggregate name plate capacity due to differences in panel orientation at each site and panel inefficiencies. Therefore it is unlikely that CUC will observe the maximum capacity evaluated in this study (29 MW) from variable generation at any given time of the day.
- A risk-benefit analysis will be required to assess if a separate operating reserve (which could be a combination of spinning and non-spinning) beyond the contingency reserve that can be economically justified to manage generation variability in day to day operation. However, day to day operation can be managed with interim solutions until an operating history is established. CUC can consider the following in the interim:
  - Install monitoring and tracking systems to record gross and net energy production from the distributed generation and use it for situational awareness in the control center.
  - Incorporate weather forecast for situational awareness and day ahead operational planning and rely on fast start units to respond to a forecasted island-wide cloud cover event.
  - Utilize solar analytical industry tools (e.g. Numerical Weather Prediction (NWP) and stochastic-kinematic cloud models) to develop solar power production profile and quantify solar variability for the island, and use that information to develop operating strategy for managing generation variability
- Once an operating history is established for the variable generation, develop operating guidelines for dynamic unit commitment and operating reserve, which should be revisited on an yearly basis.

3.3 Results Summary

The following summarizes the findings from the transmission level analysis:

- The current generation dispatch operational practices (e.g., ~ 80% capacity) limit the amount of renewable penetration capacity to 11.5 MW total.
- Should changes be made to the generation dispatch operational practices (e.g., ~ 65% capacity), additional renewable capacity up to 29 MW of total renewable capacity can be accommodated without degradation in the electric system’s reliability. This approach, however, will most likely result in higher operating cost as the current fleet

of generators will have to operate intermittently at lower loadings. The economic impacts for such an adjustment versus the addition or combination of solutions such as BESS, predictive demand management, etc. were not considered as part of this study.

- A risk-benefit analysis should be performed to assess if a separate operating reserve (which could be a combination of spinning and non-spinning) beyond the contingency reserve that can be economically justified to manage increased levels of variable generation in day to day operation.
- The OTEC plant (studied separately), consisting of four 2.5 MW units as a first phase, can serve as a renewable substitute for a comparable CUC unit; however, spinning reserve requirements would still need to be met. Its inclusion, however, will cause a slight degradation to the electric system's reliability due to the plant's slower ramp response when compared to the results found herein.
- Should additional capacity be added to the OTEC plant, it is recommended that a study be performed to evaluate the impact. Previous studies, performed by Leidos, showed a significant impact to system reliability for a larger plant interconnection. A number of additional recommendations and mitigations would need to be considered.
- The inclusion of BESSs/predictive demand side management, etc. will assist with system reliability while also allowing fewer of the existing CUC generating units to operate by compensating for the spinning reserve margin. A separate study is recommended to determine the location, size, and capability of the BESSs/ predictive demand side management, etc. and their impact on the CUC system.

Appendix A
GEOGRAPHIC ISLAND MAP WITH RENEWABLE SITES

Appendix B
DYNAMIC MODELING PARAMETERS

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E1

Stability Event Result Plots | Daytime Off-Peak

Baseline

E2

Stability Event Result Plots | Daytime Off-Peak

Scenario 1

E3

Stability Event Result Plots | Daytime Off-Peak
Scenario 3

E4

Stability Event Result Plots | Daytime Peak

Baseline

E5

Stability Event Result Plots | Daytime Peak

Scenario 1

E6

Stability Event Result Plots | Daytime Peak

Scenario 3