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2017
Integrated Resource Plan Report

Prepared for:

Caribbean Utilities Company

July 28, 2017

EXHIBITS

CHAPTER 1: EXECUTIVE SUMMARY

Siemens Industry Inc., for its Pace Global business ("Pace Global"), in coordination with Caribbean Utilities Company ("CUC"), has prepared this 2017 Integrated Resource Plan ("IRP") covering the 29-year planning period from 2017 to 2045[1]. The purpose of this document is to provide a roadmap for future resource decisions for CUC, covering issues around transitioning the generation portfolio from a largely fossil based to a renewable dominated portfolio, need for natural gas, and value of storage, and baseload renewable generation technologies. This analysis is designed to be strategic in nature and while a number of planning and operational issues are covered in detail, additional issues may need to be addressed to support an investment decision. These issues are highlighted in the signpost chapter (Appendix IV) of this report.

RESOURCE PLAN STRATEGY AND SUGGESTED NEAR AND LONG TERM ACTIONS

The IRP assessment covers a range of key decisions for CUC over the next several years with the expected acceptance of the IRP by the Office of Regulation (OfReg) by December 2017. Therefore, there are several elements that make up the suggested portfolio(s) strategy. Certain items require near-term action, others establish a guidepost for measuring future decisions, and some still require further study. Since planning is a dynamic process, it is likely that some elements of this current plan will evolve, as market conditions change, as new regulations are introduced or enter into force, and as technology improves. We note that the presented strategy is a significant departure from the status quo. This is due to a combination of economic and policy reasons. Renewable costs have come down significantly and renewables and natural gas are significantly cheaper resource strategies than continued reliance on purely diesel-fired internal reciprocating engines (ICE). Furthermore, the supply mix needs to alter to comply with the green-house gas goals under the National Energy Policy directives.

The following actions comprise the key recommendations and observations of this IRP and are illustrated in Exhibit 1. The short term strategy can be expected to be executed over a 7 year period with many of the actions being the same irrespective of the strategy or portfolio choice. The longer term strategy will evolve based on how market conditions change in the near term.

- **Develop a Renewables Procurement Strategy:** Build or issue RFPs for approximately 100 MW of intermittent renewables over the next 7 years. Even without the carbon emission reduction goals and need for capacity, the analysis demonstrates that renewables are more economic relative to thermal resources and can generate large savings that can offset capital and operating costs of solar PV and wind generation resources.
- **Invest in Energy Storage:** Develop battery energy storage detailed requirements to identify size, location, and technology of storage systems. Procure approximately 20 MW of long duration storage over the next 7 years to enable renewable integration. Continue to monitor storage applications as costs decline for batteries or other technologies.
- **Plan and Develop Natural Gas Infrastructure:** Engage into discussions to bring natural gas to the island under a combination of short term and long term contracts. The average annual quantity of natural gas consumed over the planning horizon is approximately 3,000,000 MMBtu while the largest volume is approximately 5,200,000 MMBtu at the start of the planning horizon. The natural gas consumption over time decreases as more renewables are integrated into the system. A shift to a renewables dominated future via a natural gas bridge is the more economical solution and avoids building excessive amounts of renewables and storage resources to comply with carbon reduction emission goals. Natural gas also provides optionality value to CUC and helps hedge against the volatility in diesel prices.
- **Position to Convert Existing Diesel Fired Recips to Dual-Fuel:** Work with manufacturer and

[1] Note that all cost numbers in the IRP report are in 2015 real USD.

position to convert existing diesel fired ICE to dual fuel having additional capability to burn natural gas. The development of an engine conversion project should be done in conjunction with obtaining an LNG source, import and delivery infrastructure, "LNG Supply". Once an LNG Supply is confirmed, the engine conversion project can be executed in a manner to be completed at or around the time that the LNG project is completed.

- **Assess OTEC Viability:** Continue to assess OTEC and determine whether it is a viable and economic option. While Ocean Thermal Energy Conversion (OTEC) may not be the cheapest resource, it has other benefits such as requiring less land mass, helping with renewable curtailment, and contributing to resource diversity. Baseload renewables can reduce the need for large amounts of intermittent renewable resources and help meet the island carbon emission reduction goals if intermittent renewables face permitting challenges or if natural gas cannot be brought to the island.
- **Invest in Flexible Thermal Capacity:** Given the path the utility is on, larger amounts of renewables will be sited. In order to effectively integrate renewables, purchases of reciprocating engines in the future should ensure that the units can operate at a lower set point. As shown in Exhibit 1, the procurement of flexible reciprocating engines will be an ongoing process over the next decade as resource needs evolve due to retirement of existing thermal resources and decisions on procurement of battery energy storage systems are made.
- **Support the Development of MSW and Landfill Gas Facilities:** Grand Cayman is running out of space for landfills. The government is expected to fund the development of a municipal solid waste plant and a landfill plant. CUC should negotiate PPAs to enable approximately 5 MW of municipal solid waste and 1 MW of landfill gas electricity generation facilities.
- **Facilitate Energy Efficiency Projects:** The IRP recommends residential energy efficiency programs such as air conditioning and lighting. CUC should perform additional analysis of energy efficiency and demand response programs and gain experience in conducting some programs. CUC may want to collect and assess market characterization data to have more complete information upon which to estimate costs and savings. Energy Efficiency programs will result in a loss of revenue for CUC, CUC should develop funding mechanisms with its regulator to facilitate investments in Energy Efficiency.
- **Grid Impact Analysis:** The East to West transmission transfer capability was determined to be largely adequate to support renewable generation in the East side of the island. The transfer capability is reached in a limited number of runs and CUC might be able to deploy operating procedures to mitigate the risk of over-loading during these hours instead of upgrading transmission lines, such as deploying reactive power compensation devices at strategic locations on the grid. However, additional grid impact analysis focused on intra-zonal transfer capability and system stability will be required as project locations are finalized.
- **Integration of Distributed Solar Resources:** Monitor the build-out of customer-sited solar, which could total 10 MW by 2020 and 70 MW by 2040. Perform hosting capacity analysis in the next 5 years to ensure that adequate distribution capacity is available to support integration of distributed solar and develop funding mechanisms to improve the hosting capacity of the distribution network. Prepare for system impacts through more flexible generation, including new resources at North Sound and storage resources.

Exhibit 1: Recommendations and Action Items

Recommended Actions	Key Responsibility	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
		SHORT TERM STRATEGY								LONG TERM STRATEGY					
IRP Acceptance by Ofreg	OfReg														
Develop Renewable Procurement Strategy	CUC & Ofreg														
Plan and Develop Island Natural Gas Infrastructure	CUC & Ofreg														
Pursue Conversion of Diesel Gen Fleet to Dual Fuel	CUC														
Assess OTEC Viability	CUC & Ofreg														
Support Development of MSW and Landfill Gas	All														
Develop Battery Storage Detailed Requirements	CUC														
Develop New Thermal Generation Procurement Strategy	CUC														
Facilitate energy efficiency implementation	CUC														
Perform Distribution System Hosting Capacity Analysis	CUC														
Analyze Detailed Transmission System Impact	CUC														
Perform sub-hourly analysis for implementation of renewable and storage systems	CUC														
Key Decision Points or IRP Timing	CUC														

CO2 Compliance Targets Future IRP Studies Potential Studies

Source: Pace Global

SUMMARY OF KEY METRICS FOR THE TWO SUGGESTED PORTFOLIO PLANS

In evaluating the merits of the suggested portfolio plans, this IRP assessed the performance of various portfolio options across a series of CUC's key objectives and metrics. The remainder of this report details the development of such objectives and the analysis performed to record all metrics, while the following summarizes the performance of the suggested Portfolios 5 and 6. Overall the IRP analyzed six portfolios (see Exhibit 2 below) and each portfolio was scored and ranked against the objectives defined below.

- Cost: The suggested portfolio/plan has one of the lowest expected cost across all alternatives. The costs are defined to be generation portfolio costs inclusive of fuel expenses, O&M expenses, maintenance capital, generation conversion costs, and amortized new build costs. The costs are intended to be a proxy for the utility revenue requirement and should not be viewed as projections of utility retail rates ;
- Risk: The suggested portfolio/plan offers a hedge against high fuel prices and offers reasonable retail rate stability. The risk metric is calculated as the difference between the costs associated with the high economy case and the Base case on a NPV basis;
- Reliability: The suggested portfolios meet reliability standards. For this analysis, reliability was considered as a constraint with the process ensuring that all portfolios meet the 1 day in 10 year reliability standard.
- Environmental Stewardship: The suggested portfolios meet the 2030 carbon emission reduction goals and remain within compliance over all subsequent years.
- Curtailment: The suggested portfolios minimize risk of curtailment of utility scale solar and wind generation. Curtailment was measured as a difference between the actual production and the

expected production divided by the expected production.

- Generation Diversity: The suggested portfolio plans assure diversity of resources to reduce risk associated with fuel unavailability or uncertainty and variability associated with intermittent renewable resource. The diversity was measured in two different ways – concentration risk of a single technology in terms of MWh and the total number of technologies in each portfolio. The smaller the concentration and/or greater the number of technologies, the more diverse the portfolio.
- Land Usage: The suggested portfolios while not being the most optimal in terms of land usage does not present a concern given the expected availability of land based on needs. Land usage by technology was identified on an acreage/MW basis and the portfolio MW were then used to project an acreage for each portfolio.

Exhibit 2 presents the details within each category along with a qualitative ranking of overall portfolio performance (green: positive; yellow: neutral; red: negative). The rankings have been developed using the raw scores for each category and then using proportional rankings to derive scaled scores between 1 and 10 with 1 being the best and 10 the worst. To arrive at the color rankings, a scaled score of 0-2 receives a green; 2-4: a green-yellow; 4-6: yellow; 6-8: yellow-red; and 8-10: red. To develop the summary ranking, cost was weighted at 60% of the overall score and each non-cost metric was assigned equal weight[2] from the remaining 40%. In other words, a simple average was used for the non-price weightings which was added to the cost weighting to develop the summary average rankings. The weighting methodology was discussed at the final stakeholder meetings but no clear mandate on weighting came out. In exercising its functions under the Electricity Sector Regulation Law (2018 Revision) namely, its duty to protect the economic interests of consumers by keeping electricity rates as low as reasonably possible and while keeping with industry best practices, OfReg has indicated a preference for cost to drive the rankings to a large extent and CUC supports this preference.

It should be noted that the weighting methodology for scored attributes for long term portfolios is different from the weighting methodology that would be applied on a project by project basis. The IRP is intended to develop a strategic direction for the Cayman Islands electricity sector to move in, with indicative proportions of energy sources to be developed. It therefore considers country level holistic issues such as land use and energy diversity. However, from an individual project standpoint, the applied weightings can be different from the IRP weightings. For example, when a new generation plant using a particular technology (solar, wind, OTEC, gas etc.) is called for, issues such as land use and energy diversity may have already been considered at the IRP level and through planning processes. For this reason and also with the aim of keeping electricity costs as low as possible in the face of generally higher costs in small island systems, individual projects would be expected to have higher weighting given to pricing attributes compared to non-price attributes than the IRP scoring.

The chosen weighting methodology recognizes electricity cost of production as the most significant factor that outweighs all other factors. This is similar to the weighting that would likely be used during a renewable generation Request for Proposals (RfP) process. At the RfP stage, cost including risk (which is calculated as a contingent cost) is typically weighted in the 60% to 80% range and other metrics such as quality of the anticipated outcome and timeliness are introduced into the remaining scoring.

This scoring methodology has a weakness in that options that are not compliant with government greenhouse gas policy could achieve the best score. Those options that are not compliant should therefore be set aside in the analysis, however they are useful for comparison purposes. For example the cost difference between Portfolio 3 and Portfolio 5 (which is the cost of modifying Portfolio 3 to achieve greenhouse gas compliance) is highlighted through this methodology. This scoring methodology results in the greenhouse gas compliant natural gas option with storage (Portfolio 5) as the preferred portfolio

[2] Note that diversity metric included two sub-metrics (generation based share and number of technology options) while the "supplemental" metric included both land use and renewable curtailment with equal weights assigned to the two-categories in each case.

followed by the OTEC portfolio (Portfolio 6).

As shown in Exhibit 2, a number of portfolio options were analyzed. The suggested portfolios – Portfolio 5 and 6 – both assume the availability of natural gas in the 2020/2021 time frame and both portfolios consider storage and utility scale intermittent renewables (wind and solar) and follow the mandate to meet carbon emission reduction goals. The only difference is that Portfolio 6 assumes that OTEC is available as a source of baseload renewable energy and in comparison to Portfolio 5 needs smaller intermittent renewable generation capacity and storage to meet the environmental goals.

As mentioned previously, Portfolios 5 and 6 are ranked the best and on average provide the best balance when measured against all objectives. Both portfolios meet the reliability and environmental goals while being one of the lowest cost options. Portfolio 6 does well on diversity, land use, and renewable curtailment as well while Portfolio 5 does better than Portfolio 6 on cost but not as well on other measures. Note that the portfolio costs include the additional capacity costs associated with bringing Portfolios 4 and 5 within reliability thresholds.

Portfolios 1 and 4 with diesel are ranked the lowest with low scores on several metrics. Portfolio 4 is designed to meet the carbon emission reduction goals but incurs high capital investments to comply. Portfolio 1 with diesel and no storage consistently ranks amongst the lowest across all metrics.

Exhibit 2: Portfolio Composition and Scorecard (all costs in 2015 $)

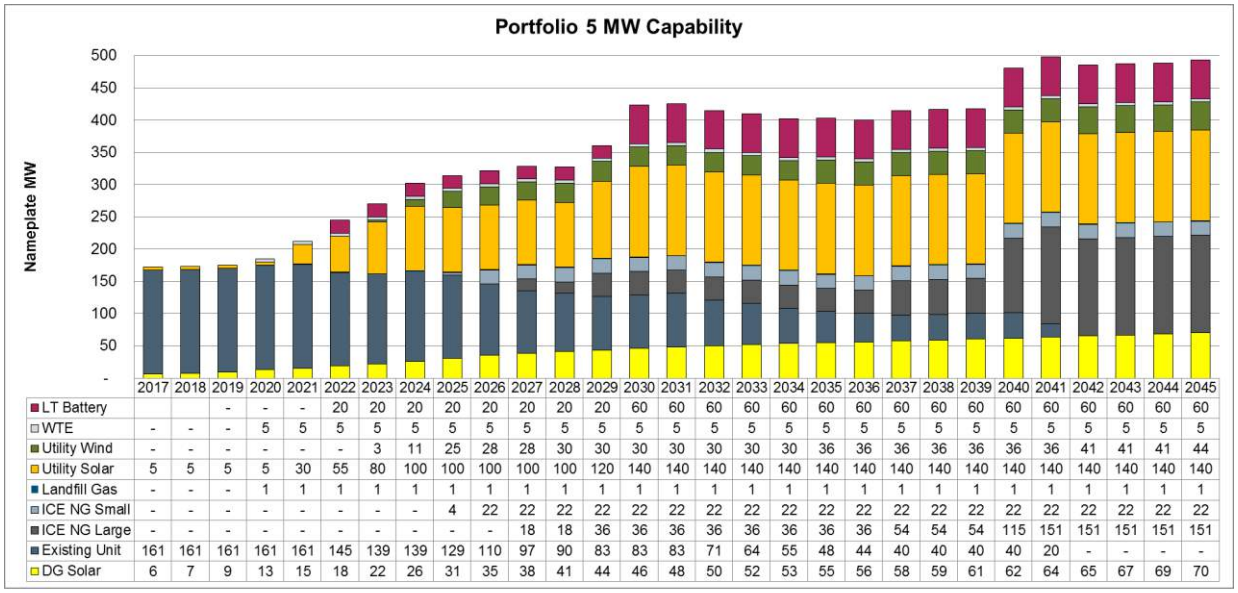
Portfolio Construct	Cost (NPV of total costs) ($MM) with LOLE adjustment	Rate Stability $MM (Range High – Base NPV)	2030 Environmental Stewardship (Emission Reduction Target 60%)	Diversity Summary (see diversity slides)	Supplemental: Land Use (Total Acres) and Renewable Curtailment	Summary Average
Weight	**60%**	**10%**	**10%**	**10%**	**10%**	**100%**
P3: NG-S	1,540 0.0	336.7 0.0	64% 1.43	2.50	6.10	1.00
P5: NG-S-GHG	1,553 0.52	342.9 0.40	68% 0.0	3.61	5.32	1.25
P6: NG-S-GHG-OTEC	1,612 2.90	341.2 0.29	67% 0.36	0.00	0.52	1.86
P2: NG-NS	1,564 0.97	337.5 0.05	57% 3.93	6.94	4.03	2.08
P4: D-S-GHG	1,729 7.62	457.2 7.83	65% 1.07	8.33	3.29	6.62
P1: D-NS	1,788 10.0	490.6 10.0	40% 10.0	8.33	6.01	9.43

P1: Diesel- No Storage; P2: Natural Gas-No Storage; P3: Natural Gas-Storage; P4: Diesel-Storage-GHG; P5: Natural Gas-Storage-GHG; P6: NG-Storage-OTEC-GHG

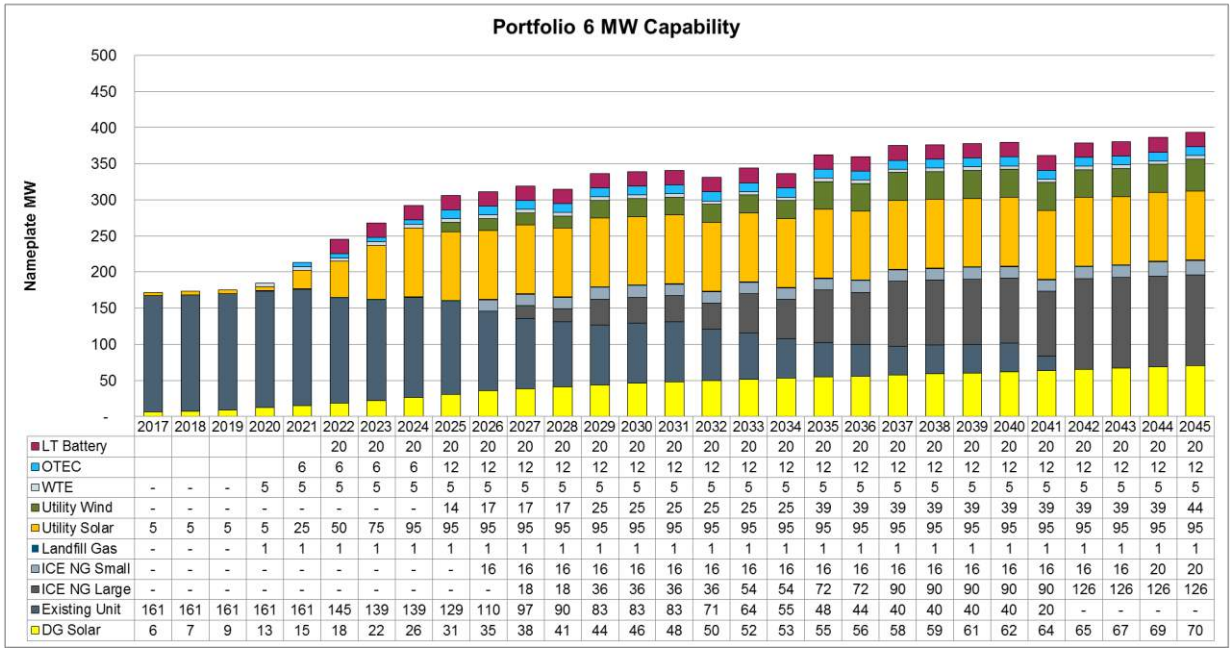
Source: Pace Global

SUGGESTED PORTFOLIO SUMMARY

Exhibit 3: Summary of Preferred Resource Plan (MW) for Portfolio 5 and 6



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
LT Battery			-	-	-	20	20	20	20	20	20	20	20	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
WTE	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Utility Wind	-	-	-	-	-	-	3	11	25	28	28	30	30	30	30	30	30	30	36	36	36	36	36	36	36	41	41	41	44
Utility Solar	5	5	5	5	30	55	80	100	100	100	100	100	120	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
Landfill Gas	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ICE NG Small	-	-	-	-	-	-	-	-	4	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
ICE NG Large	-	-	-	-	-	-	-	-	-	-	18	18	36	36	36	36	36	36	36	36	54	54	54	115	151	151	151	151	151
Existing Unit	161	161	161	161	161	145	139	139	129	110	97	90	83	83	83	71	64	55	48	44	40	40	40	40	20	-	-	-	-
DG Solar	6	7	9	13	15	18	22	26	31	35	38	41	44	46	48	50	52	53	55	56	58	59	61	62	64	65	67	69	70



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
LT Battery						20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
OTEC					6	6	6	6	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
WTE	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Utility Wind	-	-	-	-	-	-	-	-	14	17	17	17	25	25	25	25	25	25	39	39	39	39	39	39	39	39	39	39	44
Utility Solar	5	5	5	5	25	50	75	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Landfill Gas	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
ICE NG Small	-	-	-	-	-	-	-	-	-	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	20	20
ICE NG Large	-	-	-	-	-	-	-	-	-	-	18	18	36	36	36	36	54	54	72	72	90	90	90	90	90	126	126	126	126
Existing Unit	161	161	161	161	161	145	139	139	129	110	97	90	83	83	83	71	64	55	48	44	40	40	40	40	20	-	-	-	-
DG Solar	6	7	9	13	15	18	22	26	31	35	38	41	44	46	48	50	52	53	55	56	58	59	61	62	64	65	67	69	70

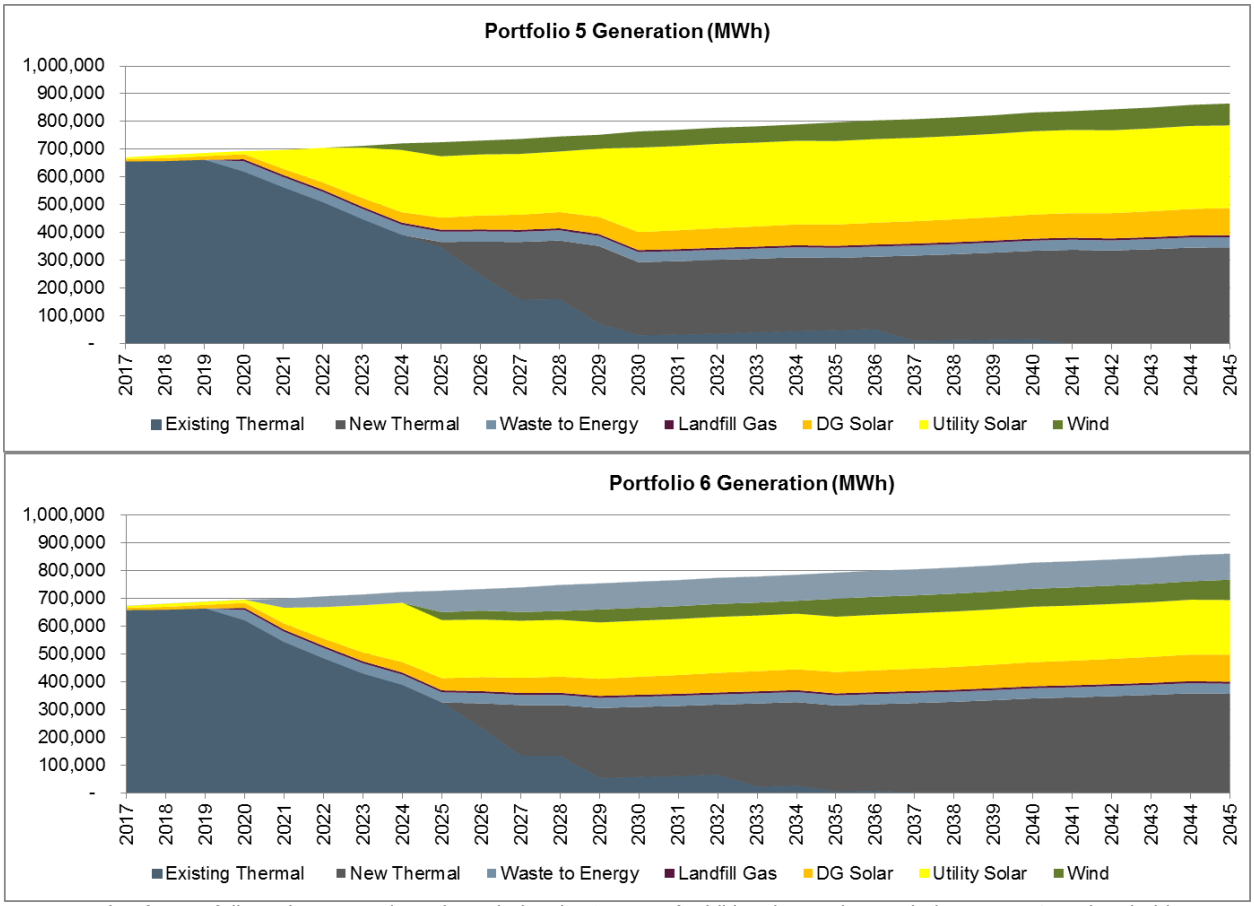
Source: Pace Global

The portfolio composition corresponding to each portfolio is summarized in Exhibit 3. In the 2017-2019 period, the portfolio mix is expected to be largely thermal units fueled by diesel. By 2020, MSW and landfill gas facilities are projected to be in-service. By 2020/2021, new utility scale solar installations are also expected to be in place with solar installations growing over the forecast horizon. In both portfolios, it is assumed that existing diesel fired thermal units (RICE or Reciprocating Internal Combustion Engines, also

called “recips”) will be converted to have dual fuel capability with the ability to burn natural gas. It would be desirable for any flexibility enhancements to be made during the unit outages for conversions if practical and economic to do so. Further, as the existing units retire over time, they may be replaced with new natural gas fired flexible ICE. Distributed generation (solar) resource penetration is expected to progressively increase over time. Diesel fired generation resources are projected to be phased-out in exchange for natural gas fired thermal capacity, intermittent renewable capacity, grid scale storage, as well as customer-sited, distributed solar PV. In addition, the suggested Portfolio 6 shows the first OTEC unit coming in service in 2021 with smaller need for utility scale thermal resources.

Exhibit 4 summarizes the projected energy requirements for CUC. The energy requirement is a function of the system demand, inclusive of losses, and plant auxiliary load. As shown, in 2017 the energy mix is largely diesel fired thermal with small amounts of distributed solar and the new 5 MW utility scale solar plant assumed to be operational in June 2017. By 2020, the energy mix changes significantly with entry of new solar and wind resources. By 2030, the energy mix shifts more towards renewables with nearly 60% of the energy requirements coming from renewable resources including utility scale and distributed scale installations. For both suggested portfolios, the new thermal resources are natural gas while existing thermal resources are converted to dual-fuel facilities. In Portfolio 6, the OTEC resource forms part of the renewable resource mix with utility scale solar forming a smaller percentage of the energy mix given the availability of the baseload renewable resource.

Exhibit 4: Projected Portfolio Energy Resources over Time (MWh) Portfolio 5 and 6



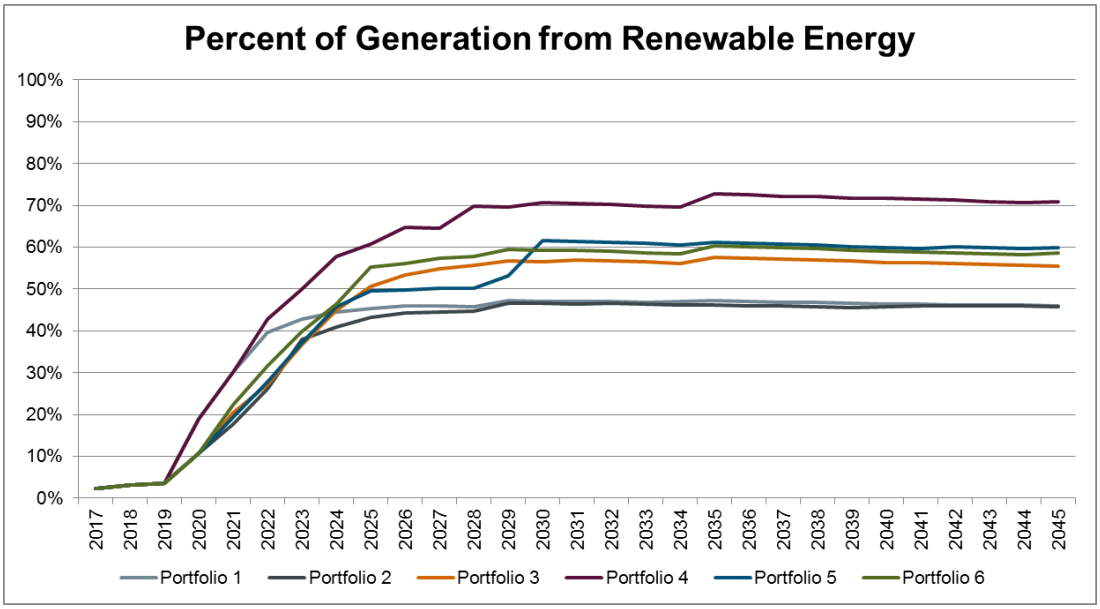
Note that for Portfolio 5, the generation mix excludes the 61 MW of additional capacity needed to meet LOLE thresholds.

Source: Pace Global analysis

RENEWABLE ENERGY GENERATION

In each of the portfolios there is a significant amount of renewable capacity added. These options include distributed generation, utility scale wind and solar, ocean thermal, landfill gas and waste to energy. Exhibit 5 shows the annual percent of generation from renewable sources based on total generation over the study time horizon. The majority of renewable technologies are added to each portfolio between 2020 and 2030. According to the National Energy Policy, the target is 70% of total electricity generation coming from renewable resources by 2037. Portfolio 4 meets this standard by 2028 and Portfolio 5 and 6 reach approximately 60% by 2037. Portfolio 5 falls short of the target as less renewable energy is required to meet the carbon emission reduction goals given the availability of natural gas. Note that the renewable energy targets came out after the portfolios were set, and this target was not the goal of this IRP, however as discussed above, the IRP has suggested portfolios that came close to this target as optimal. Future iterations of the IRP should consider studying the costs and practicalities of achieving this target.

Exhibit 5: Renewable Energy Generation



Source: Pace Global analysis

PIVOT OR FALL BACK STRATEGIES AND OPTIONS

There are potentially a number of uncertainties associated with the suggested portfolio plan. These uncertainties relate to the difficulty permitting renewable resources (particularly wind but also large amounts of solar), difficulty bringing on the Ocean Thermal Energy Conversion facility, challenges with battery energy storage maturation and safety concerns, and issues related to bringing natural gas infrastructure to the island.

Exhibit 6: Signpost Strategies

Signpost	Strategy
OTEC Does not Materialize	Pursue Portfolio 5
Not all Renewables, particularly wind, get Permitted	Pursue Portfolio 6 with more solar and baseload renewables
OTEC Does not Materialize and both wind and solar have difficulty with permits	Revisit IRP
Batteries not able to achieve maturation and scale in a safe, economic and reliable manner	Pursue Portfolio 6 with more recips and baseload renewables
Natural Gas Infrastructure Development Runs Into a snag	Pursue Portfolio 4, develop more baseload renewables to avoid building large amounts of intermittent renewables

To address the uncertainties, pivot strategies have to be considered such that the utility has an ability to rapidly switch to another portfolio strategy if market or economic conditions change. Exhibit 6 shows the key signpost and the possible pivot strategy to deal with the uncertainty. As an example, if OTEC does not materialize, the utility would fall back on Portfolio 5 which is the other suggested portfolio. If batteries don't hold their promise or if intermittent renewables have difficulty with permitting, baseload renewable options such as OTEC would have to be pursued. If natural gas infrastructure to bring natural gas to the island and the power plant complex does not materialize, Portfolio 4 with larger amounts of renewables and storage would have to be developed. There is also potential for significant volatility and risks associated with the international LNG market based on factors such as oversupply, market price risk exposure to suppliers, potential for underdevelopment of supply to meet demand growth into the long term, and shipments following the highest price environment. This analysis attempts to address some of the pricing risks through the scenario analysis but more detailed international LNG market and price impact analysis has not been conducted.

Finally, in the eventuality that both OTEC and intermittent renewables (utility scale wind and solar) cannot happen, then the utility may have to revisit the IRP and pursue other baseload generation technology options or revisit strategy with respect to demand side management and distributed solar. It's also possible that the National Energy Policy directive on carbon emission reduction goals may have to be re-evaluated.

Further, the IRP analysis indicates that many of the recommended actions over the next several years are independent of the portfolio choice. No matter what the portfolio path is pursued, certain actions have to be under-taken. For example, in all cases, the renewable procurement strategy would have to be devised, battery energy storage specifications would have to be developed, and new procurement of thermal generation assets will need to focus on more flexible reciprocating engines. Furthermore, analytical studies centered on battery integration and grid impact analysis would have to be conducted.

CHAPTER 2: PLANNING ENVIRONMENT AND IRP PROCESS

CUC has commissioned this IRP in order to develop a single, integrated process under which to evaluate a wide range of future resource decisions. This IRP represents CUC's first comprehensive assessment of major future drivers of the electric utility's operations and it is designed to address a number of key economic and policy questions affecting the electric power sector in the Grand Cayman.

KEY PLANNING ISSUES UNDER CONSIDERATION

CUC in conjunction with the OfReg and the National Energy Policy group has identified several key planning issues that require consideration in the IRP. The overall assessment has been designed to address the relevant issues through resource evaluation and screening, portfolio modeling, and special studies. The main planning elements are summarized here, with supporting detail found throughout the remainder of this report.

Transition from Pure Fossil Fuel Based Generation Portfolio to a More Diversified Portfolio

One of the key elements of the IRP analysis is demonstrating the economics of the renewable energy resources relative to fossil fuel (diesel) based resources. The IRP least cost optimization methodology demonstrates the portfolio costs and risks with and without the carbon emission reduction targets, thus showing what the portfolio size, timing, and mix is likely to be on an economic basis under a carbon regime. The analysis projects a roughly half and half mix of fossil and renewables with a certain proportion of storage for renewable integration and ancillary services.

Need for Natural Gas on the Island

One of the key questions addressed in the analysis is the need and value of natural gas on the island. This IRP has analyzed portfolios that demonstrate the costs and risks of natural gas with and without the carbon emission reduction targets and whether natural gas should be considered in the fuel mix to meet the carbon emission reduction targets and facilitate the island's transition to a more diversified energy mix.

Cost Effective and Reliable Renewable Integration

Utility scale intermittent renewable resources are supported by their current price points and the expectation of continued expected reduction in renewable costs over time. However, in the Grand Cayman, baseload renewable technologies such as Ocean Thermal Energy Conversion (OTEC) may also be viable options given the presence of deep ocean water close to the shore. The IRP addresses the trade-off between having baseload vs. intermittent renewable resources in the generation portfolio.

Renewables and Need for Storage

The amount of renewables needed to meet the carbon emission reduction goals can be different depending on availability of natural gas on the island. With only diesel, the need for renewables is higher and consequently the amount of utility scale electricity storage resources needed to integrate renewables can also be higher. This IRP has analyzed a range of storage sizes to assess CUC's portfolio performance in the future.

Carbon Emission Reduction Goals and Compliance

The National Energy Policy containing recommendations on carbon emission reduction goals was recently approved by the Cayman Islands Legislative Assembly. The reduction targets call for a downward trajectory in carbon emissions starting 2020 with a 60% reduction relative to 2014 actual emissions by 2030. In

addition, CUC has introduced a voluntary reduction target of 25% by 2025. The IRP recognizes the carbon reduction goals in select portfolios and analyzes the cost impact of meeting the carbon goals.

Local Distributed Energy Resources and Storage

New technologies are currently changing the electric utility business and offering new opportunities for resource additions to CUC's portfolio. Distributed energy resources are likely to become more widespread, primarily as a result of customers installing distributed solar behind the meter. The IRP analysis, therefore, performs an assessment of the potential penetration of solar PV at the distribution level within CUC's service territory under various potential scenarios over time.

Energy Efficiency Reductions

CUC currently has no energy efficiency targets but the IRP's load forecast explicitly assesses their potential impact on future load growth expectations in the service territory. Select energy efficiency programs have been evaluated. The IRP also relied on an independent assessment of energy efficiency reductions over time. While it was not evaluated, new rate designs, especially time of use ("TOU") and demand rate structures, may be feasible given the deployment of smart meters throughout CUC's system.

Grid Reinforcements

Most of the renewable energy development on Grand Cayman is expected to be on the East side of the island while demand centers are largely in the West. The IRP assesses the need for upgrades of East to West transmission lines. Further, the IRP assesses the reactive power requirement that need to be met by non-thermal resources, which can be material in certain situations.

IRP PROCESS AND PLANNING CRITERIA

In order to facilitate effective resource assessment and decision-making in the context of such a diverse set of issues, Pace Global has deployed a five-step process in the development of the IRP. As seen in Exhibit 7, this five-step process first identifies objectives and metrics and then evaluates all feasible resource options for analysis across a range of risks, in order to produce sufficient information to select a preferred portfolio and make prudent business decisions.

As a critical first step in this process, Pace Global and CUC have established several key objectives that are important to the electric utility as it considers its future strategy. For each objective, Pace Global and CUC have also identified a specific metric that can be recorded. Exhibit 7 lists the objectives and metrics used to drive the IRP assessment.

The second step is screening resource options. Based on stakeholder feedback, a broad universe of technology options were evaluated as part of the screening process and the technologies considered economic and viable were used for the portfolio analysis.

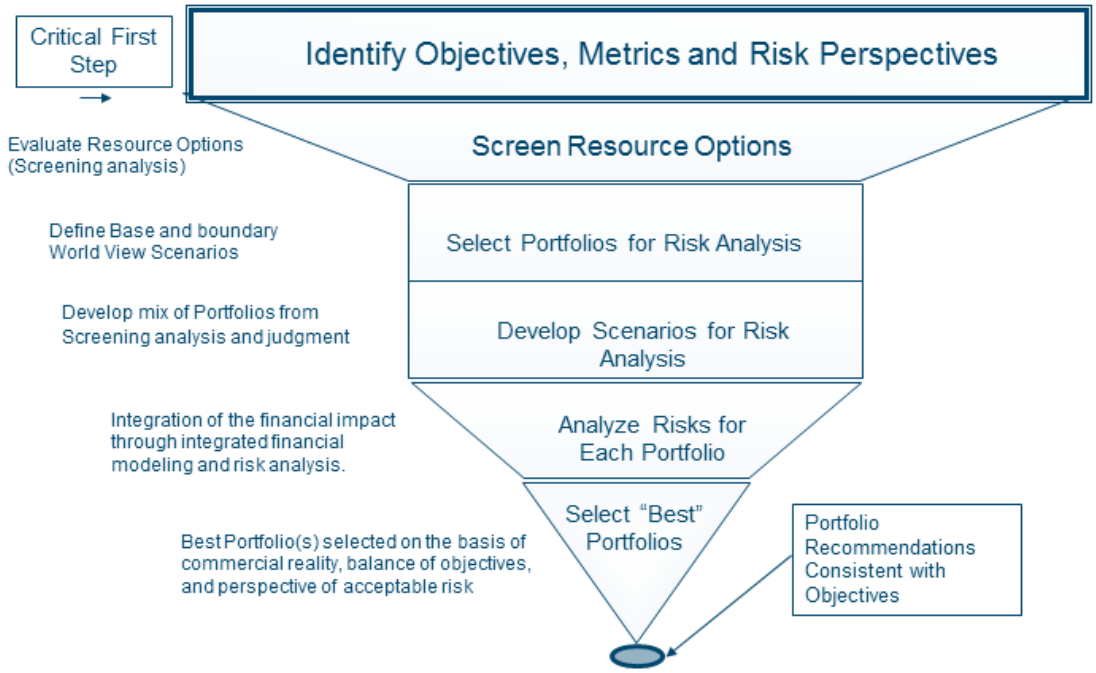
The third step was conceptualizing and structuring portfolios. The portfolios were conceptualized based on key policy and economic directives with the portfolio size, timing, and composition developed based on least cost optimization approach.

The fourth step was developing scenarios or "states of the world" for the risk analysis. Aside from the reference case, a high economy, low economy, and high technology worlds were considered.

In the fifth step, each portfolio was tested against the scenarios developed and a range of cost estimates were developed to measure cost stability.

In the final step, the preferred portfolios were identified based on the cost analysis and other objectives identified as part of the IRP analysis.

Exhibit 7: IRP Process Overview



Source: Pace Global

Exhibit 8: Summary of Objectives and Metrics

Objective	Metric
Minimize Cost	Levelized NPV (Total dollars and $/MWh) of generation portfolio costs
Cost stability/manage risks to ratepayers	Difference between base cost and highest cost scenario
Maintain reliability (used as a constraint rather than a metric)	Frequency and total MWh of loss of load events (Does the portfolio meet a one day in ten year NERC requirement for reliability?)
Environmental Stewardship	% carbon reduction by 2030 period relative to the 2014 period
Minimize Renewable Curtailment	Unavailable Energy (Actual Renewable Energy-total available renewable energy)/total available renewable energy
Achieve Diversity	%concentration on a single technology in terms of MWh AND number of technologies
Minimize Land Use	Acres/MW of land utilized for each technology option

Sources: Pace Global and CUC

The remainder of this document outlines the steps that were taken to identify and develop resource options and portfolios for evaluation against the objectives and metrics. In addition to supporting chapters on the various analysis details and assumptions, the report is organized as follows:

- CUC Situation Assessment – a review of CUC's current system and reserve margin outlook;
- Fuel Assessment – a review of the various fuel options considered for the island
- Screening Analysis – a step-by-step overview of the screening assessments performed around each of CUC's key issues;
- Portfolio Definition – a discussion of portfolio conceptualization and portfolio sizing, timing, and composition
- Scenario Analysis – a discussion on the development of the key scenarios developed for the IRP analysis
- Portfolio Analysis Results – a thorough evaluation of the key results for each of the integrated portfolios against all key metrics to allow for evaluation and measurement of tradeoffs.
- Appendices providing detail on the load forecast, distributed solar penetration, loss of load analysis, signpost analysis, and proforma sheets for the preferred portfolios.

CHAPTER 3: CUC SITUATION ASSESSMENT

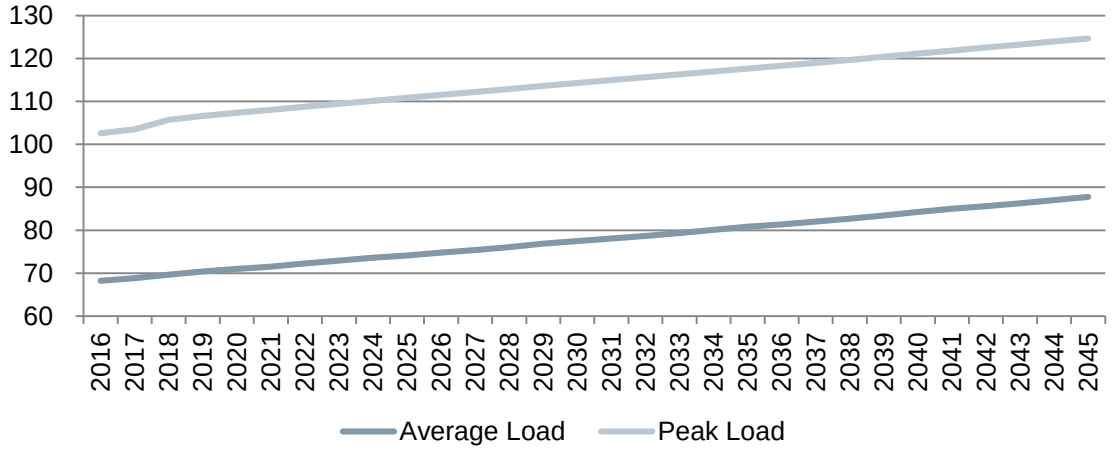
LOAD GROWTH OVERVIEW

Pace Global developed a reference case load forecast for CUC, taking into consideration the historical relationship between demand growth, weather and economic variables, which are the key drivers of loads, as well as adjustments for other drivers including customer additions, DSM penetration, and electric vehicle usage. The forecast process included the following major steps:

- Perform an historical econometric analysis of key weather and economic drivers;
- Develop the base load forecast driven by normal weather, projections for economic variables, and known customer additions;
- Make adjustments for energy efficiency, demand side management ("DSM"), and plug-in electric vehicle penetration.[3]

The load forecast expects growth in the near-term as a result of some customer additions and economic growth. However, over the long term, energy efficiency penetration is expected to offset substantial portion of load gains from economic growth and new customer additions. From 2016 to 2045, the compound annual growth rate for peak and average demand is projected to be 0.76% and 0.86%. The load forecast summary is presented in Exhibit 9, while the details of the forecast methodology and all associated analyses are summarized in Appendix III: Load Forecast Details. In addition to the reference case forecast, Pace Global also developed different load growth trajectories for use in scenario analysis. These are summarized in the chapter on MarketLink Scenario Details.

Exhibit 9: Reference Case Load Forecast Summary (MW)



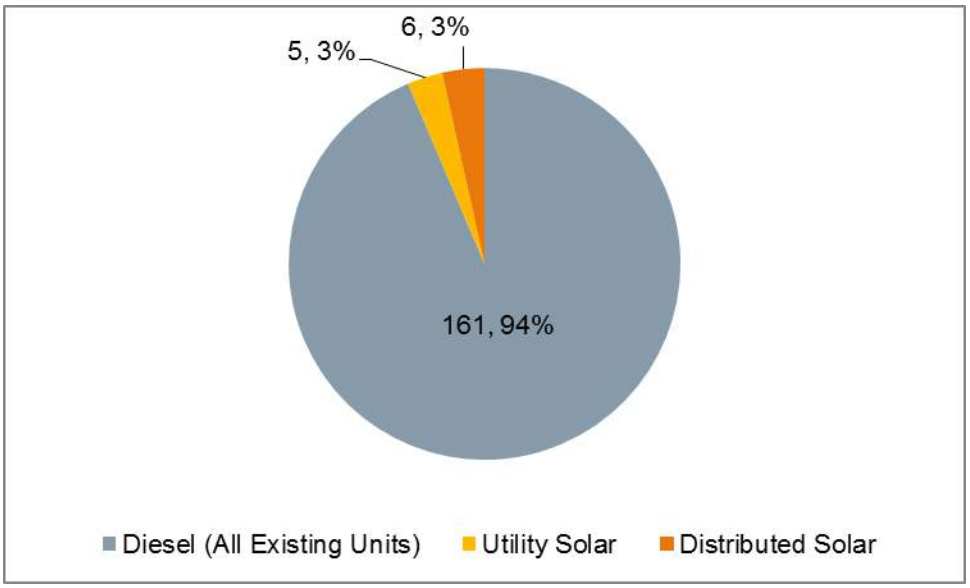
Source: Pace Global

[3] The plug-in hybrid electric vehicle demand was estimated to be low and not explicitly accounted for in the analysis.

EXISTING SUPPLY RESOURCES

Exhibit 10 summarizes the current capacity mix for CUC.[4] Currently, CUC maintains approximately 161 MW of capacity at one plant location at the North Sound location. The generation mix consists mostly of baseload reciprocating engines and some reciprocating engines that provide peaking capacity. All capacity is currently diesel as is typical of most island nations. The utility has a contract with the 5 MW Bodden Town solar facility with the plant expected to come online in June 2017. Over the years, CUC has maintained enough capacity to meet a reserve margin in the range of 35-55%. The minimum threshold is 35% and is typical of most islanded systems in the world. Exhibit provides additional detail for each plant or contract in the current portfolio.

Exhibit 10: Current Capacity Mix (MW) and % of Capacity



Sources: CUC and Pace Global

[4] Note that capacity represents the available MW for each resource type. Since energy generation is based on resource availability and variable cost of operations, the mix of actual energy production varies considerably from capacity.

Exhibit 11: CUC Plant and Contract Details

Existing Unit	Capacity MW	Technology Type	Heat Rate @ 80% Btu/kWh HHV	Commercial Operation Date	Proposed Retirement Date
Unit 1	9	ICE-Baseload	8,718	5/1/1997	4/30/2022
Unit 2	9	ICE-Baseload	8,757	5/1/1997	4/30/2022
Unit 3	4.4	ICE-Baseload	9,122	5/1/1998	2/28/2027
Unit 4	4.4	ICE-Baseload	9,267	5/1/1998	2/28/2027
Unit 19	4	ICE-Baseload	9,441	5/1/1986	7/1/2026
Unit 20	4	ICE-Baseload	9,306	5/1/1988	2/1/2022
Unit 25	3.5	ICE-Peaking	13,872	5/1/1996	4/30/2026
Unit 26	8.4	ICE-Peaking	13,872	7/1/2006	6/30/2036
Unit 28	2.7	ST	8,521	6/16/2016	6/30/2041
Unit 30	18.5	ICE-Baseload	8,370	6/16/2016	6/30/2041
Unit 31	18.5	ICE-Baseload	8,370	6/16/2016	6/30/2041
Unit 32	16	ICE-Baseload	8,370	9/7/2009	5/31/2034
Unit 33	16	ICE-Baseload	8,370	6/7/2007	5/31/2032
Unit 34	12.25	ICE-Baseload	8,546	8/3/2003	7/31/2028
Unit 35	12.25	ICE-Baseload	8,546	8/1/2000	7/31/2025
Unit 36	12.25	ICE-Baseload	8,546	8/1/2000	7/31/2025
Unit 41	1.45	ICE-Peaking	11,668	2/1/2007	2/1/2027
Unit 42	1.45	ICE-Peaking	11,668	2/1/2007	2/1/2027
Unit 43	1.5	ICE-Peaking	10,576	1/12/2012	1/12/2032
Unit 44	1.5	ICE-Peaking	10,576	1/12/2012	1/12/2032

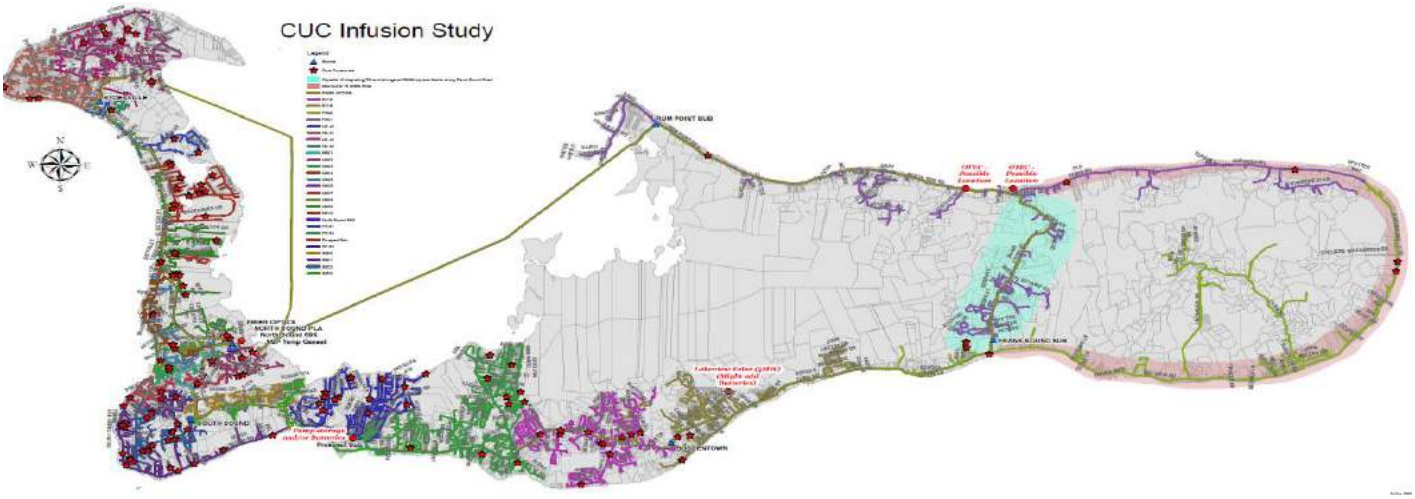
Source: CUC and Pace Global

TRANSMISSION TOPOLOGY

Exhibit 12 displays CUC's current transmission system overview, highlighting the various transmission paths available to transmit energy to serve load requirements. CUC's transmission system is operated at a 69 kV voltage level with seven, 69/13.8 kV distribution sub-stations. For modeling purposes, the transmission system was split into two zones – East and West. The transmission transfer capability between the two zones is approximately 70 MVA. The West zone[5] has nearly 90% of the demand while the East zone has the remaining but all the new renewable generation resources. The West zone contains the North Sound sub-station where the thermal generation plant interconnects. For the purposes of this study, all future thermal generation resources are assumed to be interconnected to the North Sound sub-station. All new generation facilities and storage are assumed to be interconnected to the 69 kV system.

[5] The West zone consists of North Sound, South Sound, Hydesville, Prospect, and Seven Mile beach sub-stations while the East zone includes the Bodden Town, Rum Point, and Frank Sound substation load.

Exhibit 12: Transmission System Overview



Source: CUC

PLANNING AND OPERATING RESERVE CONSIDERATIONS

The following planning and operating reserve criteria is followed by CUC:

- A static reserve margin range of 35-55% with a minimum reserve margin maintenance criteria of 35%. For the least cost optimization analysis, a reserve margin target of 45% has been chosen.
- Maintenance of spinning contingency reserves in equivalent to loss of the single largest unit on the system. This is 21 MW and corresponds to the loss of the new reciprocating combined cycle plant (Units 28 and 31 or 32)
- While CUC does not currently have large frequency regulation needs given the nature of the generation portfolio, with the expected influx of renewable resources, CUC will need to maintain regulation needs. This IRP analysis considers additional regulation reserve requirements based on the available renewable generation on the system.

SUPPLY AND DEMAND BALANCE

Given current supply and peak load expectations, CUC currently maintains a sufficient capacity margin to support reliability and reserve requirements. CUC has a generation retirement schedule for existing thermal resources. Over time, new thermal and storage resources are assumed to be added to maintain at-least the minimum reserve margin target to keep up with demand growth, retirements, and the need to meet energy and ancillary service requirements.

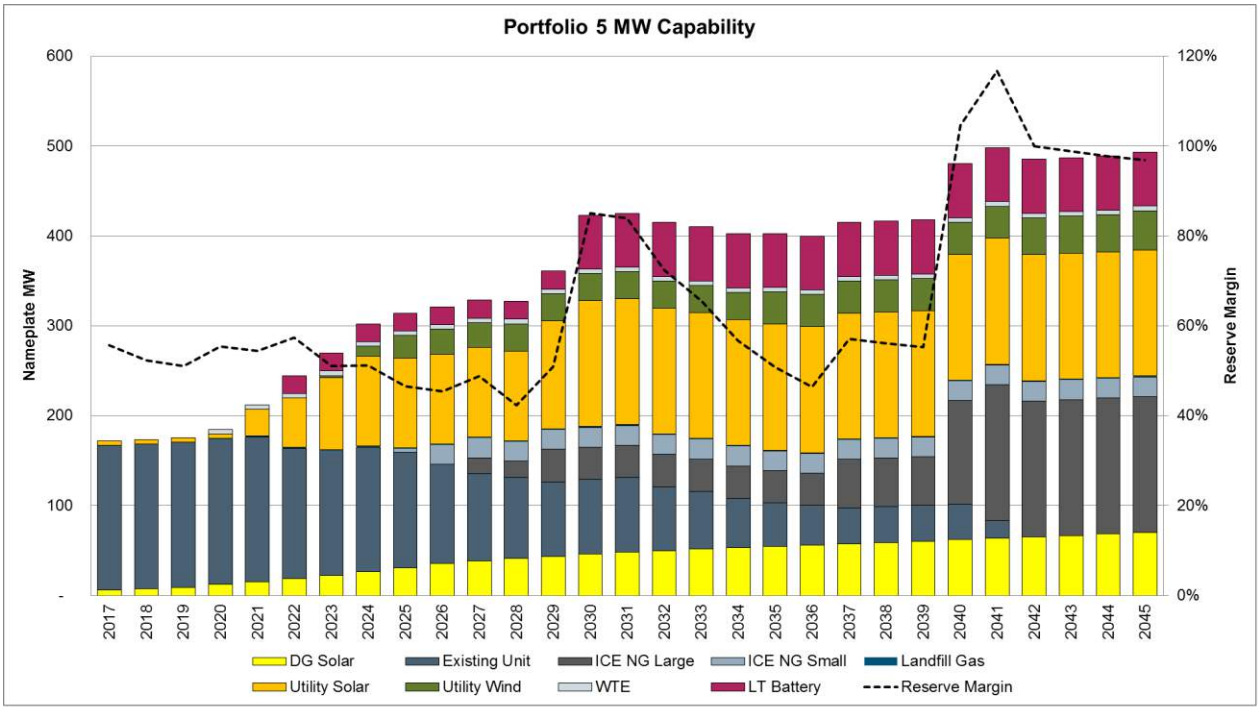
The 5 MW Bodden Town solar plant is now online and the government is expected to fund the development of a 5 MW municipal solid waste plant and a 1 MW landfill gas plant with both plants projected to begin operations in 2020. In addition to these plants, it is recommended that CUC build or contract for utility scale solar and wind generation resources. It is also recommended that CUC invest in battery energy storage and consider entering into a PPA for output from an OTEC plant, if the facility is found to be viable.

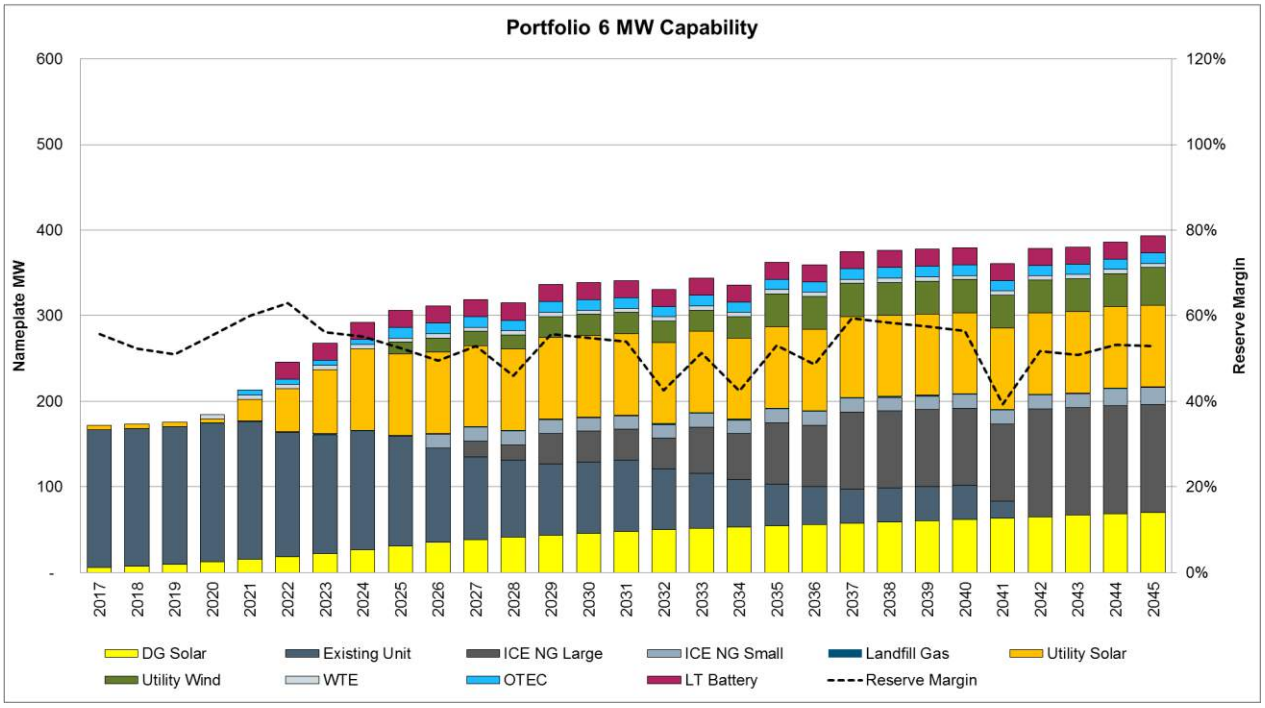
The supply outlook and reserve margins for Portfolios 5 and 6 are shown in Exhibit 13. The reserve margin is projected to be in the 40-60% range (higher in Portfolio 5 due to storage considerations) throughout the

forecast horizon with the current reserve margin being in the 50-55% range. The installed capacity is significantly in excess of the peak demand but capacity contribution to peak from renewable resources is limited to a small percentage relative to the installed capacity.[6]

[6] Wind and Solar contribution to peak has been assumed to be 15% and zero percent respectively.

Exhibit 13: Long Term Supply Outlook for Portfolios 5 and 6





Sources: CUC and Pace Global

CHAPTER 4: FUEL ASSESSMENT ANALYSIS

As part of the IRP assessment, Pace Global determined the most likely economic fuels to support power generation, evaluated the feasibility of delivering each to island, and forecasted the delivered cost of various current and potential fuels over the study horizon. The fuels ultimately forecasted included ultra- low sulfur diesel (ULSD), natural gas, and propane. Delivery of natural gas as liquefied natural gas (LNG) and compressed natural gas (CNG) were both considered, but CNG was not considered viable for this operating requirement.

To forecast the delivered cost of each fuel, supply chain concepts were developed, the costs of each segment in the chain estimated, and the segments totaled. In general, this required estimates for the commodity, shipping costs, local fuel handling, and local taxes. For reference, each fuel was expected to be available and to be shipped from the Houston Ship channel. More specifically, the components considered for each fuel are detailed below.

- Natural Gas: Projection of Henry Hub natural gas prices, basis differentials, liquefaction costs, shipping costs, regasification costs, costs associated with natural gas delivery infrastructure on the island to deliver gas from the off-take point to the North Sound power plant complex, and estimated local taxes[7].
- ULSD: Projection of West Texas Intermediate (WTI) crude oil prices that drive ULSD commodity pricing, shipping costs associated with delivery of diesel fuel to the island, and associated taxes
- Propane: Projection of West Texas Intermediate (WTI) crude oil prices as propane commodity price have historically been closely correlated with propane prices, basis differentials, shipping costs, and costs associated with propane delivery infrastructure on the island to deliver propane from the off-take point to the North Sound power plant complex

The results of this analysis are incorporated into the MarketLink Transformation scenario discussed in the MarketLink Scenario Details section of this report.

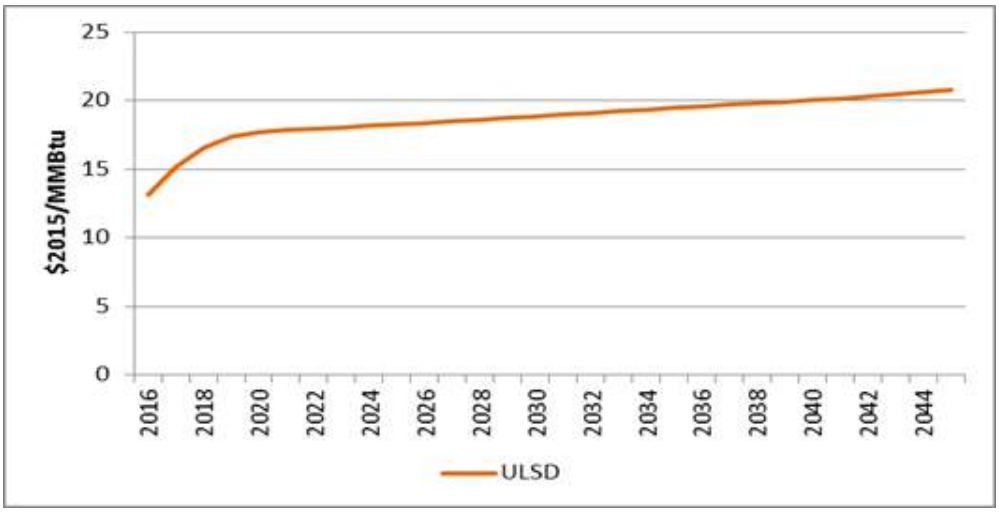
Note that even though pricing options were developed for propane, propane was not considered as part of the portfolio options for cost, price volatility, and power generation technology availability reasons.

DIESEL PRICING

CUC currently utilizes Ultra Low Sulfur Diesel fuel for all thermal generators. As briefly discussed above, ULSD pricing is highly dependent upon crude pricing, specifically WTI pricing. As evidenced in Exhibit 14 below, prior to late 2014, this resulted in U.S. Gulf Coast ULSD pricing approach of about $3.00/ gallon. However, starting in late 2014, global crude pricing began a precipitous decline sparked in part by the market realization that U.S. shale derived oil would be sustainably available at low cost for decades, and that U.S. suppliers rather than the Organization of the Petroleum Exporting Countries (OPEC) was no longer the marginal supplier of crude worldwide. At its recent low, U.S. Gulf Coast ULSD fell to about 1/3 of its previous high before settling in late 2016.

[7] Note that the generator conversion costs were not included in the delivered natural gas price projections. Conversion costs were considered the same as new build costs and included as an amortized annual cost.

Exhibit 14: Delivered ULSD Prices, USD/MMBtu



Source: Pace Global

The delivered[8] ULSD pricing increases from $15.1/MMBtu in 2017 to roughly $17.7/MMBtu by the 2020 time frame, in line with the projected increase in WTI prices[9]. The price correlations between ULSD and WTI are developed based on 5 years of historical price data. Beyond, 2020, ULSD prices are projected to continue to increase albeit at a smaller pace. As mentioned above, to forecast delivered ULSD prices, Pace Global added delivery costs and local taxes to the commodity forecast. These additional costs were derived from CUC's recent purchasing records inclusive of adders pertaining to margin, cetane discount, freight, Cayman Island duty, and wharfage fee. The Cayman government has significantly reduced the duty on ULSD and that decline has been accounted for in the delivered prices for ULSD.

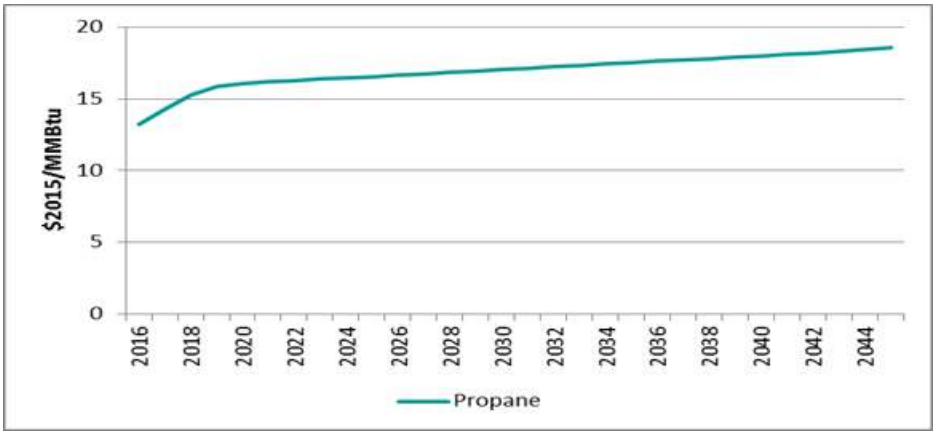
PROPANE PRICING

As mentioned above, commodity propane prices were forecast based on the WTI price forecast. Historically propane prices correlate fairly well with WTI validating this industry typical approach. Since propane prices tend to follow WTI prices, a crash in propane price is evident in late 2014, at the same time ULSD pricing collapsed. Exhibit 15 below shows the delivered propane prices over the forecast horizon with the increase in pricing over the next several years correlated to the increase in WTI prices. Further, given the strong correlation between the two commodities, propane pricing is nearly twice as volatile as ULSD, which would introduce greater budget risk than ULSD if consumed. Also note that while propane prices are less than ULSD on a dollar per gallon basis, the heat content, that is the amount of energy available in a given volume of fuel, is about 66% that of ULSD.

[8] Delivered prices to the North Sound Power Plant Complex

[9] WTI prices are projected to increase from approximately $48/barrel in 2017 to $60/barrel by 2020.

Exhibit 15: Delivered Propane Prices, USD/MMBtu



Source: Pace Global

While propane is available on Grand Cayman in small quantities, the current infrastructure was not considered to be appropriately sized for the potential demands of CUC's plants, so new shipping, storage, and delivery infrastructure would be required to provide sufficient propane. Consequently, an estimate of new infrastructure costs and likely taxes was developed and added to the commodity forecast to arrive at a delivered price.

NATURAL GAS PRICING

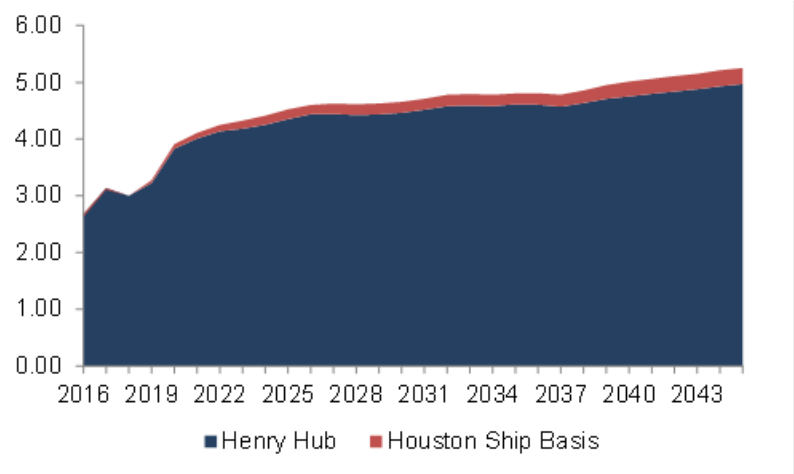
Henry Hub and Basis Adder

As with other fuel, the delivered cost of natural gas started with an estimate of the commodity cost at the Houston Ship channel. This forecast required both a forecast of Henry Hub natural gas prices, which is the central point for gas pricing in the U.S., and an estimate of the additional gas transportation charges, required to transport the gas from the Henry Hub to the Houston Ship Channel. When combined, the Henry Hub price and local basis differential allows for an estimate of local natural gas pricing. In the industry, this is known as the basis differential. Both of these components were forecast from Pace Global's Gas Pipeline Competition Model (GPCM) model[10], a commonly used industry market price clearing tool for evaluating future natural gas supply, demand, and pricing while accounting for future pipeline construction, which can change basis differentials. The Houston Ship channel was selected as the likely location for LNG departures because significant LNG liquefaction capacity has been and is expected to be built in that area, and for its proximity to Cayman. The Henry Hub price and Houston Ship Channel basis are displayed in Exhibit 16 below.

As shown, Henry Hub prices are projected to increase from $3.10/MMBtu to $3.80/MMBtu in 2020. Henry Hub prices are expected to rise as new demand (mostly LNG exports and pipeline exports to Mexico but also from the industrial and power generation sectors) increases to take advantage of relatively low prices and to mop up surplus natural gas supply. Natural gas prices are expected to continue to increase to $4/MMBtu but stay below $5/MMBtu over the long run as both shale and conventional natural gas reserves become broadly economically feasible to produce at $5.00/MMBtu at the Henry Hub.

[10] The Henry Hub price projections assume the forward pricing for the first 18 months, followed by a blend of forwards and fundamental view for the next 18 months. Pure fundamental forecast is assumed for period post that.

Exhibit 16: Natural Gas Prices, Henry Hub + Houston Ship Channel Basis; USD/MMBtu



Source: Pace Global, September 2016 Vintage Prices

Liquefaction and Shipping

Unlike the other fuels considered, there is no natural gas infrastructure on Cayman, so the required means of shipping, storage, and delivery were conceptualized and estimated as adders to the base commodity forecasts. As mentioned above, there are two means of natural gas transport without pipelines – either the gas is liquefied into LNG or compressed into CNG. Given the quantity of fuel required, shipping distance, and relative energy density of CNG, it was determined that LNG would be the most cost effective and least risky natural gas delivery mechanism.

In order to efficiently transport large amounts of natural gas over long distances without pipeline, the ability to liquefy the gas and ship it was first made commercial in the late 1950s. Consequently the means to liquefy and ship the gas is well-understood with extensive international rules and regulations governing these activities. Given the substantial capital costs involved, there are economies of scale available which historically drove focus towards ever larger projects and equipment, including transport vessels. However, interest in the ability to transport and utilize small LNG volumes economically started in the early 2000's and by 2006 design efforts for the *Coral Methane*, one of the first small LNG carriers began, and that vessel was launched in 2009. Since that time the industry has developed relatively small scale economic liquefaction, shipping, storage, and regasification equipment to meet the market.

To arrive at appropriate LNG production and delivery costs adders, Pace Global developed estimates for each of these elements in the LNG supply chain applying a combination of public and private sources[11]. Further, while LNG duties and taxes do not currently exist, it can reasonably be expected to be imposed, so an amount equivalent on an energy basis to that currently applied to ULSD was added. These cost adders are depicted in Exhibit 17 below.

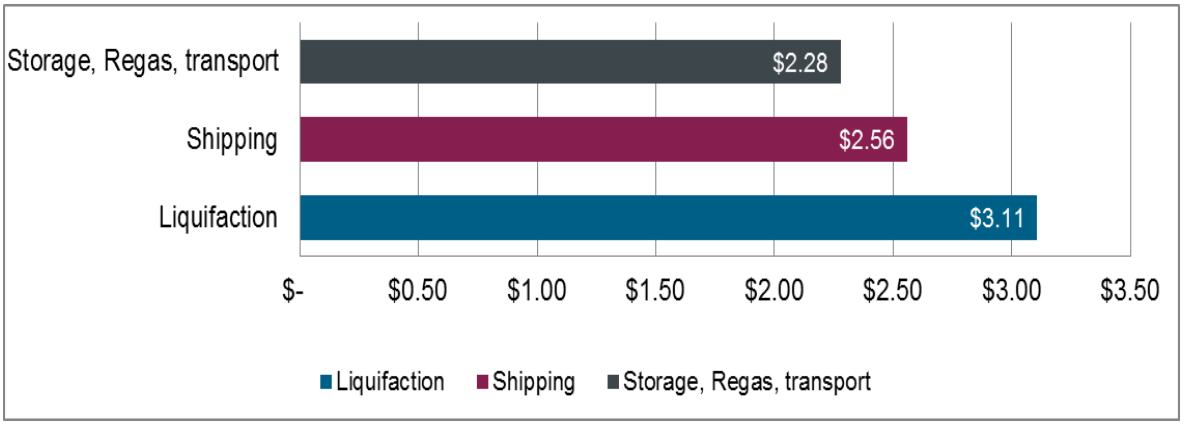
[11] Some of the sources utilized were BELCO IRP, USAID reports and publications, client work for entities focused on liquefaction facilities, and Energy Information Administration (EIA)

Island LNG Storage, Regasification, and Pipeline Infrastructure Costs

To deliver LNG to the CUC power generation units will require LNG storage, regasification, and pipeline infrastructure. Traditionally LNG storage and regasification would be installed onshore; however, new smaller scale technologies now permit the use of a Floating Storage and/ or Regasification Unit (FSRU). Given the potential natural gas volumes, an onshore storage and regasification facility with compression connected to a short pipeline to deliver gas to the CUC power plants was assumed. These costs were added to the commodity, liquefaction, and shipping costs to develop the delivered cost of LNG fuel to the power plant location. The storage was assumed to be at the same location where the current diesel storage tanks are located. The gas pipeline length was assumed to be approximately 2 miles from the storage and regasification location to the existing North Sound power plant complex[12]. The on-site storage and regasification facility should be designed to handle a maximum of 5.2 Million MMBtu a year of gas conversion with the storage facility designed to hold at-least 10 days of LNG for emergency purposes. Also note that the on-site storage was recommended based on site availability. If there permitting challenges with on-site storage or space becomes an issue, FSRU may need to be considered[13].

These cost adders are depicted in Exhibit 17 below. As shown below, the cost adders are projected to be approximately $8/MMBtu with the largest cost adder coming from liquefaction costs, followed by shipping, and finally storage/regasification. In addition, a government duty of approximately $2.17/MMBtu was assumed bringing the delivery cost of natural gas to the island to $10/MMBtu.

Exhibit 17: Delivered LNG Cost Adders, 2015 USD/MMBtu



Source: Pace Global

FUEL PRICE COMPARISONS

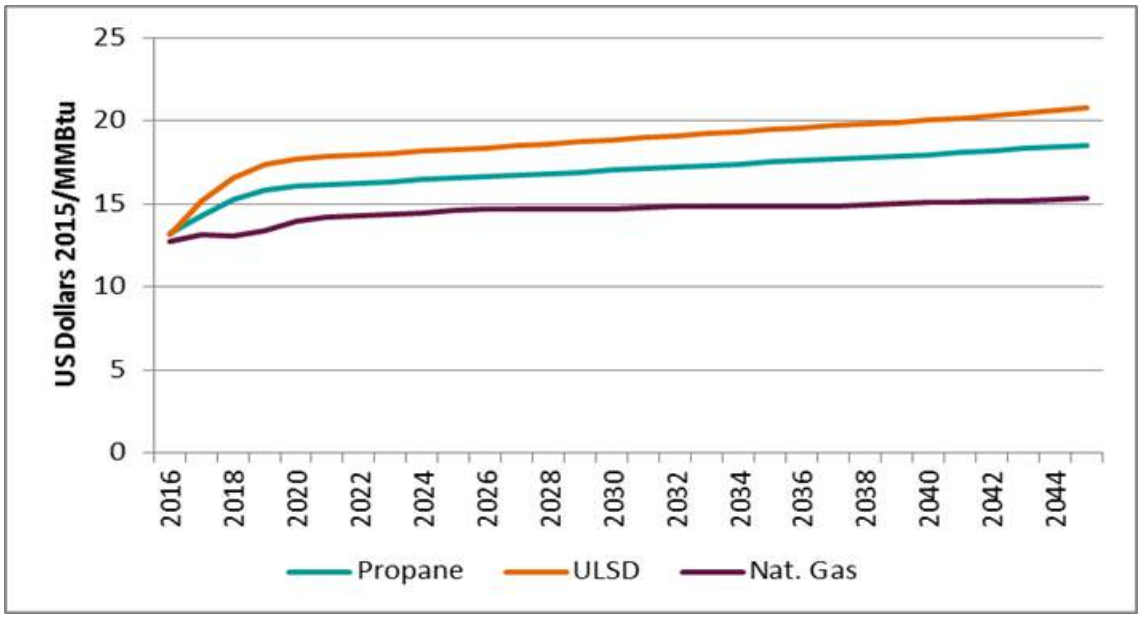
Exhibit 18 shows a comparison of the delivered fuel prices for all plants. Natural gas prices have the lowest cost, followed by propane, and finally diesel. Note that since a given volume of each fuel contains different energy content, they are not directly comparable on a volumes basis. To better illustrate the difference between fuel prices, each has been presented on the same energy basis[14].

[12] Trucking options were considered as well but were deemed to be not viable. All of the current power generating units are located at the North Sound complex and all future replacements are also assumed to be take place at the same location.

[13] Note that BELCO considered on-site storage while Jamaica has both FSRU and on-site storage.

[14] All fuels are shown to be on a higher heating value basis.

Exhibit 18: Delivered Fuel Cost Comparisons, USD/MMBtu

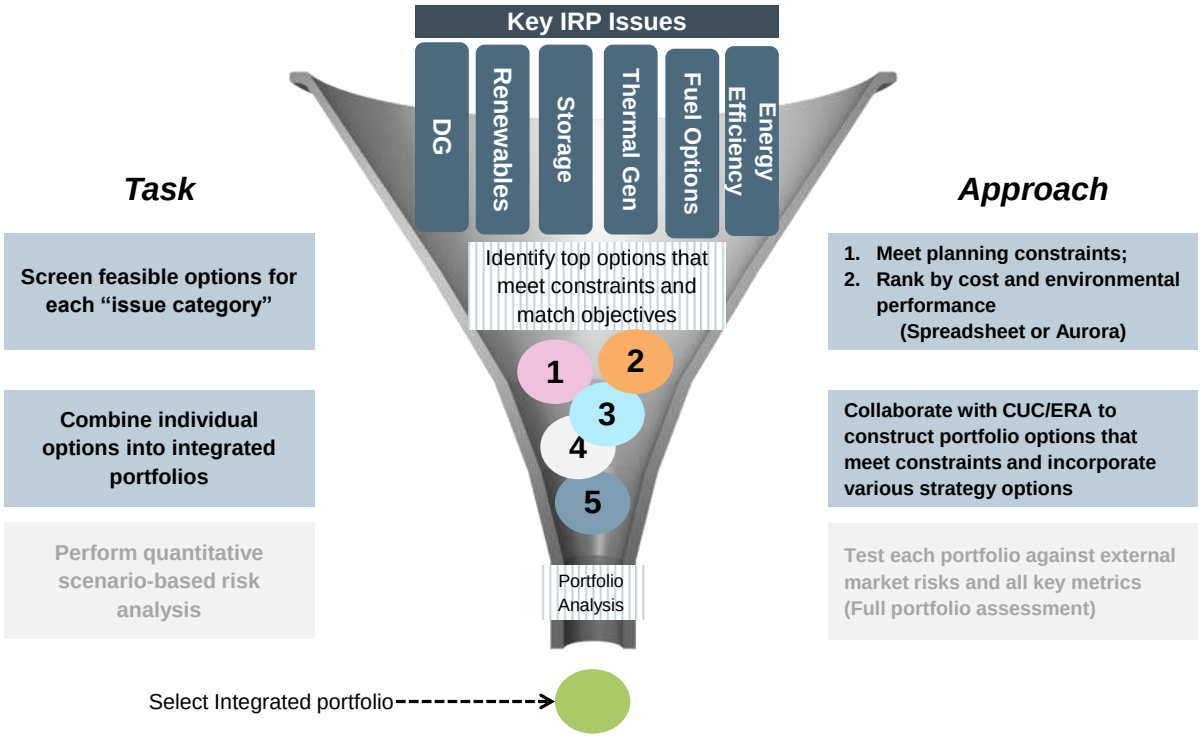


Source: Pace Global

CHAPTER 5: TECHNOLOGY SCREENING ANALYSIS

Given the large number of questions facing CUC and the large diversity of options for future resource decisions, Pace Global developed a structured screening process prior to the integrated portfolio analysis. Exhibit displays a conceptual overview of the screening process, which is designed to identify key issues associated with the IRP and identify the best or most likely resource options within each issue category to facilitate the development of integrated portfolio themes. The upper part of the Exhibit reflects the screening process on key IRP issues, with the lower part representing the fuller portfolio analysis that is performed only for the integrated portfolios that result from screening.

Exhibit 19: Overview of Screening Process



Source: Pace Global

The IRP screening process identified several key issues:

- What thermal technology options should CUC consider to meet resource adequacy and flexibility needs given the shift away from fossil fuel? ;
- What mix of long-term renewable portfolio additions should CUC secure to meet carbon emission reduction goals? ;
- What strategy should CUC pursue with respect to a procurement decision to obtain baseload renewable power from the planned OTEC facility? ;
- What are the impacts and benefits of utilizing various types of energy storage technologies at the utility scale level? ;
- What strategy should CUC pursue for demand side resources? ;

FULL RANGE OF TECHNOLOGY OPTIONS EVALUATED

As part of the IRP analysis, Pace Global evaluated a wide range of technology options, both established technologies as well as new untested technologies. There was also significant interest on the part of CUC's public stakeholders to include a wide range. Below shows the full range of technology options evaluated broken out by resource type:

1) Utility-Scale Thermal Generation Technologies
    a. Natural Gas and Diesel Fired Reciprocating Engines (4-9 MW and 18 MW size)
    b. Natural Gas and Diesel Fired Combustion Turbines in peaking application (10 MW)
    c. Natural Gas and Diesel Fired Combined Cycle Gas Turbine in intermediate or baseload operation (14 MW)
2) Utility-Scale Renewable or Zero EmissionTechnologies
    a. Conventional on-shore wind (5 to 20 MW)
    b. Conventional solar PV (5 MW and 20 MW)
    c. Ocean Based: Ocean Thermal Energy Conversion (OTEC), Tidal, Tidal Stream, and Wave
    d. Waste-to-Energy (5 MW) and landfill gas (1 MW)
    e. Small Modular Nuclear Reactor
3) Distributed Generation and Load Reduction
    a. Electric Supply: Small Solar Residential (5-20 kW), Small Solar Commercial (200-700 kW), Small Wind Residential (2.5 -10 kW), Small Wind Commercial (11-100 kW)
    b. Electric Supply: Combined Cooling Heating and Power
    c. Load Reduction: District Cooling (Sea-water) and Geothermal HVAC
4) Storage Technologies
    a. Utility Short Duration Storage (30 min Li-Ion battery energy storage, Flywheel)
    b. Utility Long Duration Storage (4 hour Li-Ion, 4 hour Vanadium Redox Flow, Na-S, Compressed Air Energy Storage, Sea Compressed Air Energy Storage

TECHNOLOGIES FATAL FLAWED

Not every technology was commercially feasible or viable and Pace Global performed a technical evaluation to demonstrate that some of the technologies were not feasible. Exhibit 20 shows the technologies that were fatal flawed. The technologies that passed the technical evaluation under-went an economic analysis and were considered as part of the portfolio design. The remaining technologies were considered not feasible or practical from the point of view of commercial application, resource potential, or extraordinary costs.

Exhibit 20: Technologies Fatal Flawed

Technologies	Rationale	Description
Sea CAES	**N**	• Technology in pilot phase; costs and performance unknown as yet; mooring below traffic, but close to surface could be a challenge
District Cooling (Seawater)	**$**	• High initial costs requires pipe be brought onshore near load (Seven Mile Beach hotel center) and consumers to share infrastructure to keep costs viable
Combined Cooling Heat and Power	**~**	• Limited applications of appropriate size • Requires distributed fuel for baseload application; siting distributed baseload engine plant concerns
Fuel Cell	**$, ~**	• Requires natural gas for fuel; extremely high cost
Small Modular Nuclear Reactor	**$, N**	• Under development, not commercially available until at least 2023; initial costs expected to significantly exceed other baseload options; poor turndown for variable load operations
Tidal	**~**	• Caribbean tidal ranges generally too low; detailed resource mapping not available/ insufficient resolution; typically need at least seven meter swing
Tidal Stream	**N, $, ~**	• Still in demonstration stage - key challenges of reliability, survivability and installability; detailed resource mapping unavailable/ insufficient resolution
Wave	**N, $, ~**	• Over 100 pilot projects worldwide, but few close to commercialization; wave energy power densities generally in the Caribbean low; detailed resource mapping unavailable/ insufficient resolution

N: New/Limited Commercial Experience $: Exceptional Cost (Other Low Cost Options) ~: Limited Resource Potential

Source: Pace Global

Sea CAES: The Sea Compressed Air Energy Storage (Sea-CAES) was considered in the Grand Cayman as the technology is being looked at by the Canadian firm, Hydro-stor. Hydrostor's Adiabatic Compressed Air Energy Storage solution operates by using electricity to run an air compressor which converts the electrical energy into compressed air. Heat from compression is captured during this step and stored to be used during generation, thus increasing the system efficiency. The system also has the flexibility to incorporate additional heat to further increase roundtrip efficiency. The compressed air stream is pressurized to the same pressure found at depth where the accumulators are located. The air displaces the water in the accumulators and is held until electricity is needed by the consumer. To satisfy the need for electricity the Hydrostor system reverses the air flow allowing the weight of the water to force the air back to surface under pressure. At surface the stored heat is added back into the air stream and the heated air travels to an expander which drives a generator efficiently converting the energy in the air back into electricity for the consumer. The Hydrostor solution is true bulk energy storage that addresses the issues

of renewable intermittency, grid load balancing, reserve capacity and peak shaving. Hydrostor's Advanced-Compressed Air Energy Storage (CAES) technology can leverage both in-ground (e.g., salt dome, mines) and underwater storage solutions. Hydro-stor has an operating project in Canada but this technology was not considered in the IRP as its still in pilot phase and costs are unknown.

District Cooling (Seawater): Deep water cooling involves using water from a deep lake or cold ocean current with heat exchangers to provide chilled water for cooling buildings. Infrastructure costs for deep water cooling systems are significant, but may be appropriate for district cooling systems for large campuses near a suitable thermal sink. Once installed, a deep water cooling system will operate inexpensively and with extremely low climate impact for many years. For the IRP work, this technology option was not considered due to exorbitant costs and lack of suitable host.

Combined Cooling Heating and Power (CCHP): CCHP (Tri-gen) offers terrific fuel economy but requires fuel such as natural gas. It also requires the right host with the commercial/industrial entity (or neighbor) having the ability use the thermal capacity. The plant either needs containerized LNG or lateral depending on location. The primary application is cooling with electricity being used completely by the host or the CCHP facility over-sized to sell electricity back to the grid. Furthermore, the likely hosts for such facilities are expected to be in high density areas with logistical challenges of bringing a natural gas lateral onto the facility. Furthermore, there are noise and aesthetics related issues as well. For these reasons, this technology was not considered as part of the portfolio design even though an economic analysis was performed.

Fuel Cells: A single fuel cell consists of an electrolyte sandwiched between two electrodes. Bipolar plates on either side of the cell help distribute gases and serve as current collectors. Depending on the application, a fuel cell stack may contain a few to hundreds of individual fuel cells layered together. This "scalability" makes fuel cells ideal for a wide variety of applications, such as stationary power stations, portable devices, and transportation. Fuel costs require natural gas for fuel and are currently extremely high cost. For the IRP analysis, fuel cells were not considered for cost reasons and also because of the current lack of natural gas infrastructure. While natural gas infrastructure is recommended for power generation purposes, fuel cells would require a more extensive natural gas infrastructure at the distribution level and lack of scale would make both the cost of fuel cells and gas infrastructure very high.

Small Modular Nuclear Reactor: Small Modular Reactors (SMRs) are nuclear power plants that are smaller in size (300 MWe or less) than current generation base load plants (1,000 MWe or higher). These smaller, compact designs are factory-fabricated reactors that can be transported by truck or rail to a nuclear power site. SMRs will play an important role in addressing the energy security, economic and climate goals of the U.S. if they can be commercially deployed within the next decade. For this IRP, this technology was not considered due to limited commercial experience with the technology, very high costs, and inflexible operations.

Tidal: Tidal power is a form of hydropower derived from tidal flows and currents. Tidal power may be tapped by two main means.

- Tidal barrage technologies: these employ potential energy by entrainment of tidal floods to capture water for the movement of low-head turbines.
- Tidal stream technologies: these employ kinetic energy by harnessing currents to move turbines in a manner similar to wind turbines.

Tidal barrage technology is one of the most mature technologies available for harnessing tidal energy. It is best suited for regions where the local geography results in a large tidal range in a suitable channel. The development of tidal barrage systems has been hampered by the large infrastructural cost of such projects, their long construction times as well as opposition to their environmental impacts. Tidal stream technology is immature, with most prototypes having been deployed only within the last ten (10) years but is being

facilitated by the increasing availability of test berths and hubs.

However, Caribbean tidal ranges are generally too narrow. Resource mapping resolution is too low and tidal swings are less than seven meters which makes it unsuitable for applications.

Wave: Wave power is distinct from the diurnal flux of tidal power and the steady gyre of ocean currents. Wave-power generation is not currently a widely employed commercial technology, although there have been attempts to use it over the last decade.

Wave power devices are generally categorized by the method used to capture the energy of the waves, by location and by the power take-off system. Method types are point absorber or buoy; surfacing following or attenuator, oriented parallel to the direction of wave propagation; terminator, oriented perpendicular to the direction of wave propagation; oscillating water column and overtopping. Locations are shoreline, near shore and offshore. Types of power take-off include hydraulic ram, elastomeric hose pump, pump-to-shore, hydroelectric turbine, air turbine and linear electrical generator. Some of these designs incorporate parabolic reflectors as a means of increasing the wave energy at the point of capture. These capture systems use the rise and fall motion of waves to capture energy. Once the wave energy is captured at a wave source, power must be carried to the point of use or to a connection to the electrical grid by transmission power cables.

The best wave conditions are in medium-high latitudes and in deep waters (greater than 40 feet deep). As yet, no devices have been installed further than 6 km from shore or in waters deeper than 50 meter. In general, wave energy power densities in the Caribbean are low relative to other locations.

TECHNOLOGIES CONSIDERED FOR ECONOMIC ANALYSIS

After the fatal flaw analysis, the remaining twenty technology options were carried over to the levelized cost analysis phase and are discussed in the sections below.

THERMAL TECHNOLOGY SCREENING

Pace Global considered a number of thermal technology options focused on application (baseload vs. intermittent vs. peaking) and type (reciprocating vs. turbine) type. The bulk of CUC's current generation fleet is reciprocating engines and the company has significant operating experience with the technology.

For baseload purposes, both reciprocating engines and CCGT options were considered. For reciprocating engines, two size options were chosen - one in the 4-9 MW range and the other in the 18 MW range. Both sizes are currently being used by CUC. For combined cycles, a 14 MW CCGT option was selected. Each size had a natural gas and diesel option. Reciprocating engines burning propane are not very common and were not considered. Both reciprocating engines and CCGT also offer the flexibility with low minimum operating levels that help enable the integration of renewable resources.

For peaking purposes, simple cycle gas turbines were considered with sizes in the 10 MW range with natural gas, diesel, and propane option.

Exhibit summarizes the cost and operating profiles of the various thermal generation options considered.

Exhibit 21: Thermal Technology Cost and Operating Characteristics

Thermal Technology	MW	Capital Cost ($/kW)	HR (Btu/KWh)	Online Date	Asset Life (Years)	VOM ($/MWh)	FOM ($/KW-yr.)	Ramp Rate	Min Operating Levels
Diesel ICE Large	18	2017: 1,427 2020: 1,419 2025: 1,405 2030: 1,391 2040: 1,363	8,350	> 2023	30	2.71	44.52	2.5 MW/min ; 1 hr.	30%
Diesel ICE Small	4	2017: 1,921 2020: 1,910 2025: 1,891 2030: 1,872 2040: 1,835	8,120	> 2023	30	2.71	44.52	2.5 MW/min ; 1 hr.	30%
Diesel CC	14	2017: 2,522 2020: 2,514 2025: 2,502 2030: 2,489 2040: 2,474	9,623	N/A	30	6.0	20	4 hr.	40%
Diesel SCCT	10	2017: 2,284 2020: 2,278 2025: 2,266 2030: 2,255 2040: 2,244	11,528	N/A	30	4.0	20	1 hr.	50%
Natural Gas RICE Large	18	2017: 1,262 2020: 1,252 2025: 1,242 2030: 1,229 2040: 1,205	7,910	> 2023	30	2.71	44.52	2.5 MW/min ; 1 hr.	30%
Natural Gas RICE Small	4	2017: 1,474 2020: 1,465 2025: 1,450 2030: 1,438 2040: 1,408	7,800	> 2023	30	2.71	44.52	2.5 MW/min ; 1 hr.	30%
Natural Gas CC	14	2017: 2,515 2020: 2,508 2025: 2,495 2030: 2,483 2040: 2,468	9,592	N/A	30	6.0	20	4 hr.	40%
Natural Gas SCCT	10	2017: 2,199 2020: 2,193 2025: 2,182 2030: 2,171 2040: 2,160	11,753	N/A	30	4.0	20	1 hr.	50%

Source: Pace Global, in consultation with CUC.

RENEWABLE SCREENING

Pace Global evaluated a number of renewable screening options. Amongst the intermittent renewable technologies, utility scale wind and solar PV technologies were considered. Pace Global also considered baseload renewable technologies such as OTEC, landfill gas, and Municipal Solid Waste. OTEC technology, while still nascent, has significant potential in Grand Cayman and was considered for the economic analysis given that CUC has a power purchase agreement negotiated from the vendor. Both

landfill and municipal solid waste technologies were considered given shortage of landfill facilities on the island and strong government support for the technologies. Exhibit 22 summarizes the operating characteristics of intermittent and baseload technologies considered. A brief description of the renewable technologies is provided below:

Wind: Wind power is the conversion of wind energy into a useful form of energy, such as using wind turbines to make electrical power, windmills for mechanical power, wind pumps for water pumping or drainage, or sails to propel ships. A wind farm consists of several individual wind turbines which are connected to the electric power transmission network.

On-shore wind is a mature renewable technology, which appears to have converged on a horizontal axis (generally three-blade) machine. The basic equipment varies little between sites and scales, with steel tubular towers being the predominant support for wind turbine generators (WTG) above 1 MW.

Offshore-wind is at an early stage of deployment, with only a decade since the first commercial installation in Denmark. Offshore wind farms can harness more frequent and powerful winds than are available to land-based installations and have less visual impact on the landscape, but construction costs are considerably higher and they must be installed in relatively shallow water. Due to the depth of the ocean close to the shore, off-shore wind turbines were not considered for Grand Cayman.

On the Grand Cayman, a couple of wind sites – Mastic and Quarry – have been identified by CUC. These sites are located on the East side of the island. For the IRP analysis, both Mastic and Quarry sites were considered but overall wind development was limited to 45 MW due to permitting challenges. Furthermore, a turbine size of 2.75 MW has been considered at a hub height of 80 m.

Solar PV: Solar photovoltaic (PV) panels are used to convert sunlight to electricity directly. Photovoltaic conversion is the direct conversion of sunlight into electricity with no intervening heat engine. When light photons of sufficient energy strike a solar cell, electrons move within the silicon crystal structure, resulting in a voltage between electrodes. Solar photovoltaic panels are solid-state. At present, panels based on crystalline and polycrystalline silicon solar cells are the most common. Thin-film solar panels, especially cadmium telluride (CdTe) and copper indium gallium diselenide (CIGS) based cells, are gaining market share because of their lower costs and increased efficiencies. For example, the efficiencies of multi-junction cells and concentrating PV have been reported to be as high as 40% and most panels available in the market have efficiencies of the order of 15%.

Solar cells are arranged together on a solar module, which is installed on the roofs of houses or in large ground mounted installations. Solar modules generate Direct Current (DC) electricity, which needs to be converted into Alternating Current (AC) before it can be fed into the electricity grid and used in homes and businesses. The device used to convert DC to AC is called an inverter and thus, the two key components of PV generation, are the modules and the inverter.

In Grand Cayman, solar PV potential is large. However, due to space constraints on the West side of the island, the IRP assumes that most utility-scale solar PV installations will occur on the East side of the island with interconnections to the 69 kV transmission system. Solar PV installations can suffer from panel degradation over time. It has been assumed that the degradation curve will follow a profile similar to the Entropy contract with new plant capacity factors in the 25% range and declining to 21% over the 20 year life of the system.

Waste to Energy: Waste-to-Energy (WtE) technologies range from the mature application of direct incineration to emerging technologies which process the waste to another form for combustion to avoid direct combustion.

The dominant WtE technology is incineration, chiefly because of its relatively low capital cost and operating

risks. Some separation or pre-processing of the waste may be required for the various processes. The main incineration technologies utilized worldwide are moving grate, fluidized bed and rotary kiln combustion chambers. Exhaust gas boilers, steam turbines, turbo alternators and flue gas cleaning systems complete the electricity generation process. These incineration systems form the majority of the world's WtE facilities. Alternative thermal WtE technologies are, at this stage, more expensive and carry greater operating risks.

In the Grand Cayman, landfilling space is becoming an issue with the national Government planning a WTE plant of 5 MW to be operational in 5 years. While the pricing is not clear yet, CUC is required to buy at avoided costs of 10 cents CI + value of capacity (if any). The facility is expected to be an incinerating facility.

Landfill Gas: Landfill gas is generated through the degradation of municipal solid waste (MSW) by microorganisms. The quality of the gas is highly dependent on the composition of the waste, presence of oxygen, temperature, physical geometry and time elapsed since waste disposal. In anaerobic conditions, as is typical of landfills, methane and CO2 are produced in equal amounts. Methane (CH4) is the important component of landfill gas as it has a calorific value of 33.95 MJ/Nm3 which gives rise to energy generation benefits. The amount of methane that is produced varies significantly based on the composition of the waste. Most of the methane produced in MSW landfills is derived from food waste, composite paper and corrugated cardboard. The rate of landfill gas production varies with the age of the landfill.

Landfill gas is gathered from landfills through extraction wells placed, depending on the size of the landfill. Landfill gas must be treated to remove impurities, condensate, and particulates. The treatment system depends on the end use. Minimal treatment is needed for the direct use of gas in boiler, furnaces, or kilns. Using the gas in electricity generation typically requires more in-depth treatment. If the landfill gas extraction rate is large enough, a gas turbine or internal combustion engine could be used to produce electricity to sell commercially or use on site.

OTEC: OTEC uses the temperature difference between cooler deep and warmer shallow, or surface ocean waters, to run a heat engine and produce useful work, usually in the form of electricity. However, if the temperature differential is small, this impacts the economic feasibility of ocean thermal energy for electricity generation. OTEC plants pipes in hot and cold seawater and run them through heat exchangers and water condensers, in the process spinning turbines that generate electricity. It can only be done efficiently where the thermal gradient within the upper 1,000 meters of the ocean is more than 20° Celsius. Given the absence of large scale OTEC plants anywhere else in the world, proof of commercial viability is needed. Assessments of commercial viability need to be under-taken aside from efforts to reduce costs.

The most commonly used heat cycle for OTEC is the Rankine cycle using a low-pressure turbine. Systems may be either closed-cycle or open-cycle. Closed-cycle engines use working fluids that are typically thought of as refrigerants such as ammonia or R-134a. Open-cycle engines use vapor from the seawater itself as the working fluid. OTEC can also supply quantities of cold water as a by-product. This can be used for air conditioning and refrigeration and the fertile deep ocean water can feed biological technologies. Another by-product is fresh water, distilled from the sea. Demonstration plants were first constructed in the 1880s and continue to be built, but no large-scale commercial plants are in operation.

OTEC is being explicitly considered in the IRP analysis as a viable baseload renewable resource. Even though the technology is relatively new, CUC has a PPA in hand which makes the technology option a viable option in a portfolio analysis. The OTEC contract has an energy and capacity component with the capacity component beginning after the first few years of successful commercial operation. The bulk of the environmental impact assessment analysis is complete and the recommendations of the Integrated Resource plan will be a critical path forward to the permitting process.

Specific portfolios are being set up to demonstrate the trade-off between OTEC and intermittent renewable resources considering both cost and non-cost objectives. As a baseload resource, the OTEC is modeled

not to provide any spinning reserves.

Exhibit 22: Comparison of Renewable Generation Options (Costs in 2015 USD)

Renewable Technology	MW	Capital Cost ($/kW)	HR (Btu/KWh)	Online Date	Asset Life (Years)	VOM ($/MWh)	FOM ($/KW)
Wind	2.75	2017: 2,889 2020: 2,452 2025: 2,106 2030: 1,901 2040: 1,829	N/A	> 2020	20	N/A	35
Solar PV Large	20	2017: 2,599 2020: 2,129 2025: 1,698 2030: 1,505 2040: 1,290	N/A	> 2020	20	N/A	20
Solar PV Small	5	2017: 2,709 2020: 2,229 2025: 1,771 2030: 1,569 2040: 1,345	N/A	> 2020	20	N/A	20
Waste to Energy (WTE)	5	2017: 14,853 2020: 14,764 2025: 14,617 2030: 14,471 2040: 14,184	14,360	2020	30	9	404
Landfill Gas	1	2017: 2,675 2020: 2,659 2025: 2,633 2030: 2,606 2040: 2,555	10,002	2020	30	8	180
OTEC	6.25	N/A - PPA Modeled	N/A	First Unit 2021, Second Unit 2025	30	N/A - PPA Modeled	N/A - PPA Modeled

Source: Pace Global analysis

DISTRIBUTED GENERATION SCREENING

In addition to grid scale resources, distributed generation resources were considered for the analysis. CUC currently has a "CORE" program. Given the program, both residential and commercial distributed solar options were considered. Also, distributed wind options were considered as well. Furthermore, the analysis considered thermal distributed generation such as combined cooling heat and power applications. The table below summarizes the various DG options considered in Exhibit 23.

Exhibit 23: Distributed Generation Options (Costs in 2015 USD)

Distributed Generation Technology	kW	Capital Cost ($/kW)	HR (Btu/KWh)	Online Date	Asset Life (Years)	VOM ($/MWh)	FOM ($/kW-yr.)
Distributed Solar Residential (5-20 kW)	5-20	2017: 2,993 2020: 2,770 2025: 2,397 2030: 2,193 2040: 1,934	N/A	2017-2045	20	N/A	21
Distributed Solar Commercial (200-700 kW)	200-700	2017: 2,394 2020: 2,216 2025: 1,918 2030: 1,754 2040: 1,547	N/A	2017-2045	20	N/A	19
Distributed Wind (2.5-10 kW)	2.5-10	2017: 11,146 2020: 9,459 2025: 8,124 2030: 7,335 2040: 7,057	N/A	N/A	20	N/A	48
Distributed Wind (11-100 kW)	11-100	2017: 9,288 2020: 7,883 2025: 6,770 2030: 6,112 2040: 5,881	N/A	N/A	20	N/A	48

Source: Pace Global analysis

A 20 kW size was considered for commercial solar applications while an 8 kW size was considered for residential. This was based on average size of installation for current CORE customers. Note that the CORE program will be in place until the distributed solar penetration achieves the 6 MW target. Past that, the program may be extended till a 10 MW target is achieved[15]. There are currently very few distributed wind installations in the Cayman and given cost and aesthetics related issues, distributed wind has limited potential on the island.

With respect to distributed thermal, combined cooling heat and power applications were considered. Two sizes were considered. As shown, CCHP was more economic than distributed wind but not as economic as distributed solar. Furthermore, siting CCHP facilities can be challenging and in addition natural gas infrastructure is needed. For those reasons, while an economic analysis was performed, the CCHP option was not considered for the final portfolio design.

STORAGE OPTIONS SCREENING

The IRP analysis considers battery energy storage as a key enabling resource for renewable integration. Other forms of storage were also considered (such as CAES and thermal storage) but determined not viable as discussed previously.

Furthermore, the analysis considers grid scale or “in front of the meter” battery energy storage. Behind-

[15] The CORE program recently hit the 6 MW limit. The program size has been increased to 8 MW. For modeling purposes, it is assumed that the program will hit 10 MW.

the-meter or distributed applications of storage have not been considered in the IRP analysis. Distributed storage can play an important role in providing benefits related to demand charge reduction as well as providing benefits related to ancillary services. Analysis of such benefits can potentially be considered by CUC in a subsequent study as outlined in the signpost chapter.

Grid-scale Storage has a number of applications as shown in the discussion below.

- **Energy Shifting and Arbitrage:** Energy storage resources in other jurisdictions have enabled utilities to time shift energy purchases between peak and off-peak hours to reduce the cost of meeting the load as it fluctuates over time. With projected increasing renewable resources on the Grand Cayman system, load and price volatility can increase as the net load becomes more variable.
- **Ancillary Services:** Energy storage systems can also provide regulation (both up and down), frequency response, and contingency reserves to the system. Using energy storage devices to provide ancillary services reduces the burden placed on thermal generators to provide ancillary services, allowing them to operate at more efficient set points. It is widely accepted that higher renewable penetrations can drive increased variability over very short time-scales, which may increase the need for reserve products, specifically regulation reserves. In addition to the increased need for ancillary services, renewables introduce the additional challenge of meeting ancillary services requirements with fewer conventional generators online during hours with high renewable output. Both of these factors contribute to potential cost increases associated with relying on thermal resources to integrate higher levels of renewables on the system. Providing a portion of these ancillary services with energy storage resources has the potential to reduce costs. In addition to the above services, renewable integration analysis has identified an increased need for load following services under high renewable penetration levels. These reserves may be in anticipation of forecast errors and sub-hourly fluctuations in net load on time-scales down to 5 minutes. Similar to regulation services, providing load following with thermal generation requires plants to operate at less efficient set points, with increasing power costs. Energy storage resources may contribute to reducing these renewable integration costs by reducing the reliance on thermal plants to accommodate.

    - **Regulation Services**: Regulation is the use of online generation, storage, or load that is equipped with AGC and that can change output quickly (MW/min) to track the moment-to-moment fluctuations in customer loads and to correct for fluctuations in generation. Regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area. The BESS is fast-acting with high ramp rates, and it responds to AGC signals to provide regulation up or regulation down services. While there are quite a few battery technologies, Lithium Ion batteries are beginning to see wide adoption for this application. For regulation services, the energy need is not as great, but the batteries have high duty cycles. Batteries may need to respond multiple times each hour, for the full year, resulting in very high asset utilization. For the IRP analysis, the battery storage is set up to carry regulation reserves, as appropriate.

    - **Spinning Reserve Services**: A BESS can be used to provide spinning reserves, which are required in order to cover the energy needs in the event of a failure of an operating resource. A 30-minute storage is usually enough, as batteries can be immediately deployed to respond to system contingencies and can remain operational for 10 minutes until a fast-start reserve generating unit can be deployed. A BESS in a spinning reserve application is subjected to fewer duty cycles (potentially 20 to 50 a year). For the IRP analysis, battery energy storage is considered an eligible resource to carry spinning reserve.

- **Avoided Renewable Curtailment:** At higher renewable penetrations, Pace Global has identified the potential for events in which the system cannot fully accommodate high renewable output due to a combination of low load conditions, flexibility constraints on thermal generators, and the need to maintain a minimum level of conventional generation on the system to provide the ancillary services described above. The battery energy storage system can enable integration of larger amounts of renewable energy by reducing instances of curtailment and help meet the island's carbon emission reduction goals.

- **System Peaking Value:** Long Duration energy storage systems can provide value to a system by dispatching during peak load conditions, reducing the amount of conventional generation capacity required to meet resource adequacy obligations. Since the ability of a storage resource to provide capacity during a potential shortage will depend on its state of charge prior to the event, ELCC method is sometimes used to approximate capacity contribution of renewable resources[16]. For this analysis, the duration based methodology has been used as a basis for the storage peak credit.

Storage Applications and Storage Duration Considered in the IRP

For the CUC IRP, both long (4 hour storage duration) and short duration (30 minute) batteries Li Ion battery energy technology was considered. Vanadium Redox flow batteries were also considered as part of long-duration storage alternative but not included in the modeling due to cost and efficiency reasons. A 30 minute short duration battery was considered. Sensitivity analysis was conducted to determine the value of short duration storage. However, the short duration batteries were found not to create additional value as savings in fuel and reserve value did not cover battery costs. Hence as a final portfolio design, only long duration batteries were considered.

The long duration storage was also assumed to have a 100% capacity contribution. This was an approximation hinged upon the duration based methodology with the assumption that the battery system that CUC controls can provide peaking capability at the maximum discharge level that the battery system can sustain over a 4-hour period. For example, a 20 MW, 4 hour duration battery has a capacity contribution of 100% or 20 MW while a 2 hour battery can have a capacity contribution of 50% or 10 MW. This approach assumes that the operator is precisely aware of the time periods in which the battery system will be required to provide reliable capacity and is always able to charge the system in advance of the need. While it is likely that the operator will be able to anticipate the high load conditions that drive the system capacity needs to a large extent, events driven by forced outages or low wind levels are less predictable and may result in a lower capacity contribution than is determined by this methodology.

Cost Assumptions for BESS

The annual battery costs consist of three elements: the amortized capital costs, the ongoing FOM, and the replacement FOM. Below is more detail on the individual components of the battery costs:

- Capital Cost: Pace Global assumes a $2300/kW capital cost based on review of public sources and discussions with vendors, primarily through our affiliates at Siemens Energy, Inc. The current price point for such batteries varies, but on average the cost is about $2,300/kW for a 4 hour Li Ion BESS with costs declining to $1700/kW by 2020. The cost estimate includes standard "balance of plant" items, including inverters, transformers, and control systems as well as EPC (Engineering,

[16] In lieu of a standard methodology, some jurisdictions have applied a minimum duration constraint for counting storage towards capacity adequacy. In California, resources must be capable of running for 4 hours over three consecutive days to qualify for resource adequacy payments. As a result, SCE used a 4-hour duration as a proxy for this capability in a recent Local Capacity Requirements (LCR) RFO.

Procurement, and Construction) costs to integrate the facility with CUC's infrastructure.

- Ongoing fixed operations and maintenance ("FOM") Costs: The ongoing FOM is associated with periodic maintenance on all parts of the system including fire suppression, cooling, fans, inverter maintenance, fuses, fans, cooling, capacitors, transformer, sensors (pressure, temperature), switchgear (both medium voltage and high voltage), and protective relays. In addition, there is periodic tightening of all connections at different parts of the system and grounding verification. The ongoing FOM for the BESS is assumed to be $10/kW-yr. based on discussions with battery vendors and review of publicly available information.

- Cell Replacement Cost: Replacement FOM can be a significant cost adder to the total FOM costs of the BESS. The Replacement FOM relates to the replacement of degraded battery cells over the life of the BESS. Pace Global has assumed that all cells have to be replaced in the 8th year of the 15 year operating life of the BESS with a replacement cost of $60/kW-year (amortized) over the remaining life of the system. The replacement cost is a function of the cell costs as a % of overall battery costs (approximately 43%) and the prevailing cost of the battery energy storage system.

Exhibit 24 summarizes the annual costs of the BESS inclusive of FOM cost and degradation assumptions for each of four capacity sizes that have been evaluated.

Exhibit 24: Annual Cost of BESS across Various Capacity Sizes

Storage Technology	MW	Capital Cost ($/kW)	Cost ($kWh)	Efficiency	Battery System Life	FOM ($/kW-yr.)
Battery Energy Storage Short-Duration (1 MW, 30 min) Li Ion	1	2017: 686 2020: 514 2025: 378 2030: 316 2040: 961	NA	82%	15 year life	First 7 years: 10 7-15 years: 70
Battery Energy Storage Long Duration (1 MW 4 hours) Li Ion	1	2017: 2,298 2020: 1,723 2025: 1,264 2030: 1,058 2040: 961	2017: 580 2020: 430 2025: 316 2030: 264 2040: 240	90%	15 year life	First 7 years: 10 7-15 years: 70
Battery Energy Storage Long Duration (1 MW, 4 hours) Redox Flow	1	2017: 4,730 2020: 3,480 2025: 2,269 2030: 1,763 2040: 1,479	2017: 1182 2020: 870 2025: 567 2030: 440 2040: 370	75-80%	15 year life	First 7 years: 20 7-15 years: 35

Note that the capital costs represent all-in, annual expected costs. Cell replacement costs are included in the FOM costs.
Source: Pace Global

LEVELIZED COST OF ENERGY ANALYSIS

The levelized cost of energy analysis assesses the relative economics of each technology based on capital and operating considerations. The capital portion includes amortized capital over the life of the technology, fixed O&M expenses, fuel expenses, and variable O&M expenses.

The levelized cost analysis was considered as a leading indicator of technology competitiveness but the size, mix, and timing of the portfolio design is dependent on a number of other considerations including reserve margin constraints, carbon constraints, energy needs, and ancillary service needs. All technologies that were part of the levelized cost analysis were considered as potential options for the portfolio design. These technology options were included in the model with the model's long term capacity expansion algorithm selecting the least cost portfolio of generation options optimizing the energy, capacity, ancillary services, and curtailment requirements. A description of the Long Term capacity expansion optimization is provided in Appendix V.

The financing assumptions utilized in the study are summarized in Exhibit 25. The financing parameters are converted into an annual capital amortization or capital charge rate that reflects amount of annual capital recovery needed to earn a return on and of capital, including recovery of depreciation expenses.

Exhibit 25: Financing and Dispatch Assumptions[17]

	Book life	Debt Life	Depreciation	Equity Costs	Debt Costs	Capital Structure (D/V)	Income Taxes	Tax Credits	Capital Charge Rate (%)
ICE	30	20	SL*	11.2	5.1	55%	NA	NA	7.7%
CC	30	20	SL*	11.2	5.1	55%	NA	NA	7.7%
SCCT	30	20	SL*	11.2	5.1	55%	NA	NA	7.7%
Wind	20	10	SL*	11.2	5.1	55%	NA	NA	8.6%
Solar	20	10	SL*	11.2	5.1	55%	NA	NA	8.6%
Battery Storage	15	10	SL*	11.2	5.1	55%	NA	NA	10.6%
OTEC	30	20	SL*	11.2	5.1	55%	NA	NA	7.7%
WTE	30	20	SL*	11.2	5.1	55%	NA	NA	7.7%
Landfill	30	20	SL*	11.2	5.1	55%	NA	NA	7.7%

*SL is straight line depreciation; D/V: Debt to Value;

Source: CUC and Pace Global.

The financing assumptions were combined with the technology assumptions to arrive at the levelized cost estimates for each technology. Exhibit 26 summarizes the results of the analysis in the early, mid, and late period. The range of costs reflects differences in capital costs and fuel costs as applicable. The lower end of the range reflects the fuel cost assumptions in the low economy scenario and the higher end of the range reflects the assumptions in the high economy scenario. The mid-point of the range reflects the base or the reference case scenario. The underlying assumptions around dispatch for non-renewable technologies vary between the early to mid to late period. As the levelized cost analysis preceded the production cost analysis, the dispatch assumptions for thermal resources were based purely on operating history and expected renewable penetration over time.

A few takeaways as depicted in Exhibit 26:

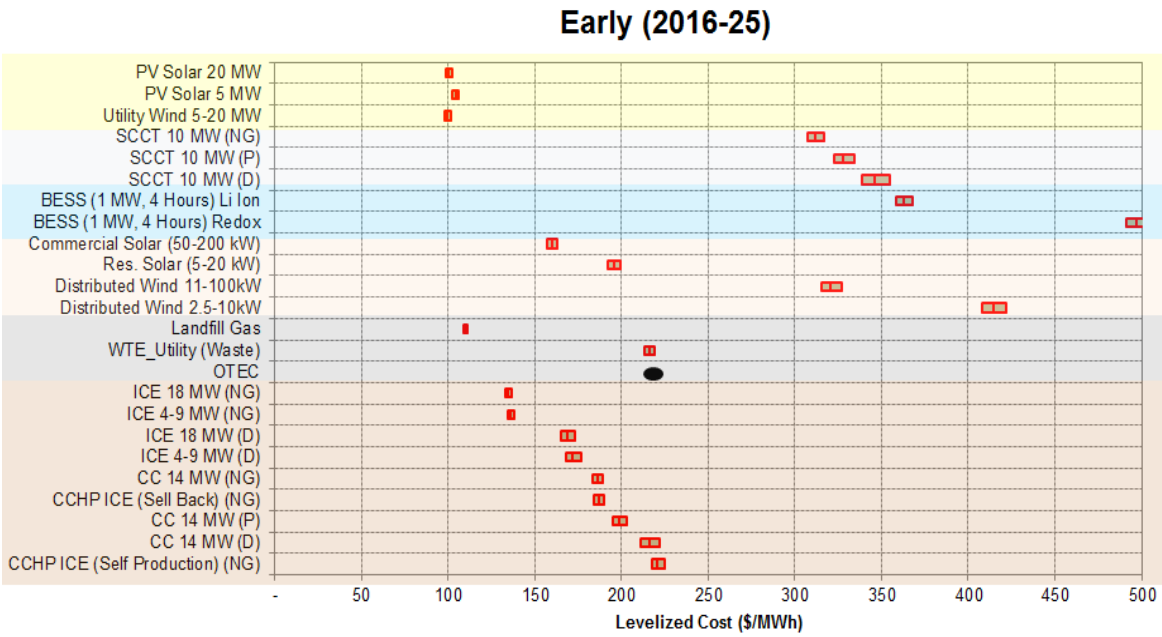
- Given the high fuel costs on the island and declining cost trajectory of renewables, renewable technologies are economic relative to thermal even in the early period. With that being said, utility wind and solar costs cannot be completely looked at it in isolation due to the need to balance

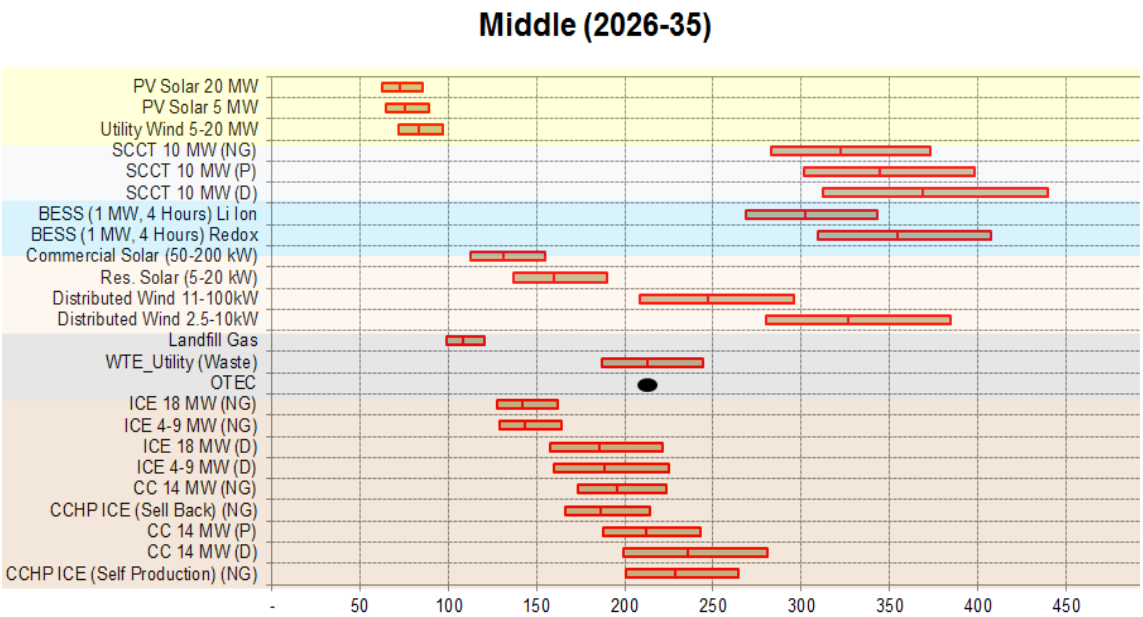
[17] Note that all specific resource options shown were developed from available data and in order to establish planning-level operational and cost estimates. The IRP does **not** limit or pre-determine CUC's choice of technology or vendor.

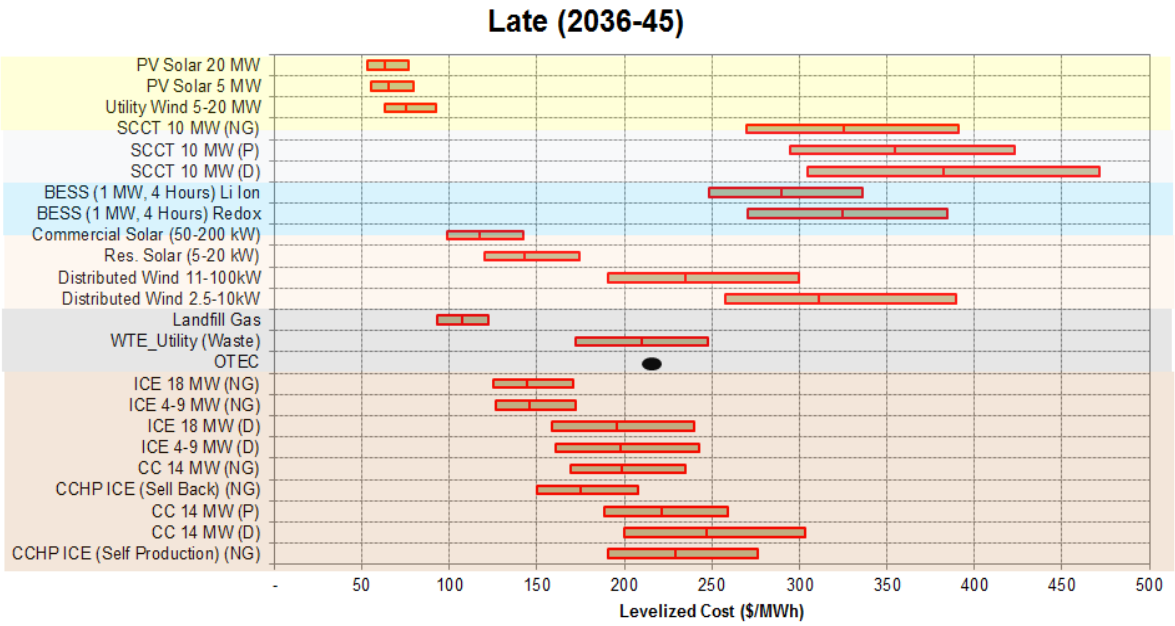
intermittent generation resources

- In the mid to late period, the relative economics of renewable technologies becomes even more compelling.
- Peaking thermal resources are one of the highest cost resources.
- Distributed solar economics improves over time with reductions in capital costs.
- Some of the storage technologies start to compete well with conventional thermal peaking technologies in the middle to late period. However, in reality, levelized costs for storage cannot be looked at it isolation as storage is not a generation resource.
- The OTEC technology economics was based on PPA pricing instead of a projection of a capital cost.

Exhibit 26: Levelized Cost Estimates for technologies Considered in the Analysis







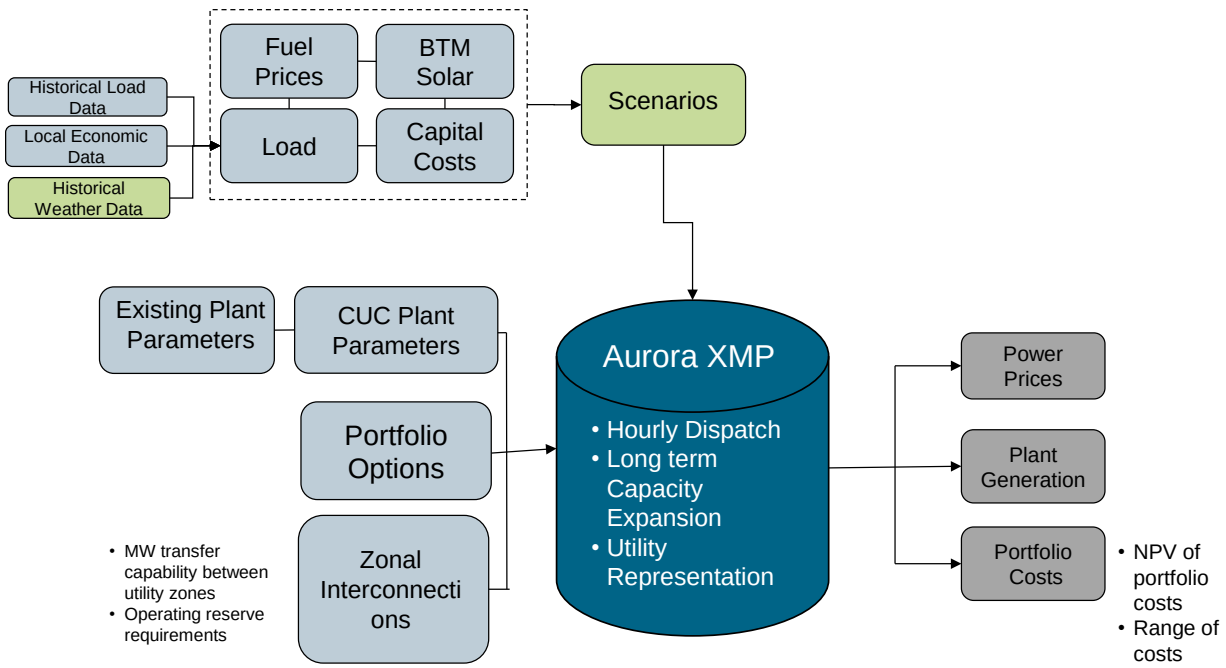
Source: Pace Global analysis.

CUC SYSTEM MODELING FRAMEWORK

Pace Global utilized the AURORAxmp Electric Market Model ("Aurora"), developed by EPIS, to perform all analysis related to system dispatch and portfolio costs. Aurora was deployed as a zonal chronological hourly dispatch model that simulates the behavior of power markets based on a production cost basis, with the ability to track specific portfolio performance. Aurora solves for each simulated hour a set of prices, revenues, dispatch costs, and emissions for specified regions and plants. With Aurora, Pace Global was able to simulate the entire CUC portfolio. The general structure of the model, with key inputs and outputs, is shown in Exhibit 27.

Based on information supplied by CUC, Pace Global developed a CUC system zonal model with representative transmission transfer capability between the two zones. Pace Global, in conjunction with CUC, also developed an hourly load forecast for CUC through 2045 (see Appendix III: Load Forecast Details for information on that process).

Exhibit 27: Overview of Aurora Modeling Process



Source: Pace Global

The CUC power network was modeled in a zonal market modeling framework. Two zones were modeled – East and West – with transmission transfer limits between the two zones. All of the existing thermal capacity is located at one place and is considered to be in the West zone. The new central wind and solar plants were assumed to be in the West zone based on availability of land and site specific studies conducted by CUC in the past. All new thermal capacity was assumed to be in the West at the current North Sound location.

INTEGRATED PORTFOLIO DEVELOPMENT PROCESS

As a first step, Pace Global developed portfolio concepts based on discussions with the CUC and ERA. These portfolio concepts are summarized below and were designed to answer the following technical and policy questions:

- Should natural gas be considered an alternative fuel?
- What is the value of storage?
- What is the cost of compliance with green-house gas emission targets?
- How much more renewables and storage is needed with diesel vs. natural gas?
- What is the value of baseload renewables relative to intermittent renewable resources?

The portfolios concepts are summarized in Exhibit 28 below:

Exhibit 28: Portfolio Concepts

	Portfolio Short Name	Portfolio Description	Thermal Generation	Renewable Generation	Storage
1	P1: D-NS	Base: Maximize renewable energy with no storage	Diesel Based Thermal Generation	Utility Contracted Wind, Solar, and WTE/LFG	None
2	P2: NG-NS	Portfolio with no GHG Target	Natural gas based thermal generation	Utility Contracted Wind, Solar, and WTE/LFG	None
3	P3: NG-S	Portfolio with no GHG Target	Natural Gas Based Thermal Generation	Utility Contracted Wind, Solar, and WTE/LFG	Yes
4	P4: D-S-GHG	Portfolio with Full GHG Compliance and Storage	Diesel Based Thermal Generation	Utility Contracted Wind, Solar, and WTE/LFG	Yes
5	P5: NG-S-GHG	Portfolio with Full GHG Compliance and Storage	Natural Gas Based Thermal Generation	Utility Contracted Wind, Solar, and WTE/LFG	Yes
6	P6: NG-S-GHG-OTEC	Portfolio with Full GHG Compliance storage, and OTEC	Natural Gas based Thermal Generation	Utility Contracted Wind, Solar, OTEC, and WTE/LFG	Yes

Source: Pace Global

The questions above all highly relevant to investment and policy decision making in the Grand Cayman. The benefit of bringing natural gas to the island has to be demonstrated such that the island can transition to a renewable based economy and meet the carbon emission reduction goals. Natural gas can also provide optionality to the utility in terms of being able to switch from one fuel to the other based on prevailing market prices. Further, natural gas can serve as a hedge against the volatility associated with diesel prices. Typically, natural gas can be hedged for longer periods of time compared to diesel.

The value of storage is important to bring out from a renewables integration standpoint particularly in light of the fact that existing thermal resources can be limited in terms of the flexibility they can provide. It is also important to understand the costs associated with carbon compliance and also what the costs are of meeting carbon emissions with diesel compared to natural gas given that diesel has 25% higher emission rate than natural gas. Finally, CUC has a PPA on the table for baseload renewables and its important to bring out the value of baseload renewables vs. intermittent renewables. To answer the questions, the portfolios were set up as shown in Exhibit 28. Comparing various portfolio costs and builds over the IRP forecast horizon as shown in Exhibit 29 below provides the analytical framework to develop responses to the questions.

Exhibit 29: Portfolio Questions Answered

Relevant Question	Portfolio Addressed
Should natural gas be considered an alternative fuel?	Portfolios 1 vs 2
What is the value of storage?	Portfolios 3 vs 4
What is the cost of compliance with green-house gas emission targets?	Portfolios 2 vs 5
How much more renewables and storage is needed with Diesel vs. Natural gas?	Portfolios 4 vs 5
What is the value of baseload renewables relative to intermittent renewable resources?	Portfolios 5 vs 6

Source: Pace Global

The second step in the process was to estimate size, timing, and composition of the portfolio based on least cost optimization techniques. Pace Global used Aurora's long term capacity expansion framework[18] to develop portfolio designs based on carbon emission reduction goals, minimum reserve margin constraint, maximum annual technology buildout, ancillary services constraint, and energy requirements. A more detailed description of the constraints is shown below.

Carbon Emission Constraint: The carbon constraint imposed on the model in effect was designed to realize a reduction of 60% by 2030 (relative to 2014 levels)[19] and stay at that level for the rest of the forecast horizon. In developing this constraint, only the electricity sector carbon emissions were considered. The carbon constraint effectively imposed a limit of approximately 170 Million tons of CO_2 to be met by 2030.

Minimum Reserve Margin Constraint: All portfolios imposed a minimum reserve margin target of 45%.

[18] For a detailed description of Aurora's long term capacity expansion logic, see Appendix IV

[19] The National Energy policy directive calls for an economy wide reduction from 12.1 metric tons/capita to 4.8 metric tons/capita or a reduction of 60% by 2030 relative to 2014 levels.

Historically, CUC has maintained a reserve margin in the 35-55% range with the minimum being 33%. The model builds capacity to maintain the minimum levels but can build more, if economic.

Maximum Annual Technology Buildout: Annual technology buildout limits were imposed on the model. No more than 20 MW of utility scale solar was allowed to be built in a single year.

Ancillary Service Constraint: The model jointly optimized the energy and ancillary services needs of the system. The ancillary services demand was included as an input to the model and represented the contingency reserves and regulation needs of the system. The contingency reserve needs were maintained at 21 MW levels for all forecast years and these were honored on an hourly basis to account for the single largest generation contingency. The regulation requirement was modeled as a percentage of renewable capacity available on an hourly basis and thus the model saw a larger need during the day time with larger amounts of solar generation available and less during the night time with only wind generation available.

Energy Requirement: The energy requirements are a function of the system demand. The retail load forecast was developed and in order to develop net energy for load numbers, system losses and generation auxiliary load was added to the retail demand forecast.

The findings of the screening analysis ultimately supported the development of the six integrated portfolios shown in Exhibit 28 for assessment across a range of external market conditions. Exhibit summarizes each of these portfolio options, with descriptions of their components under each of the major screening categories.

Exhibit 30: Summary of Integrated Portfolio Options

	Portfolio Description	Thermal Generation	Renewable Generation	Storage
1	Base: Maximize renewable energy with no storage	Small ICE: 8 MW Large ICE: 162 MW	Wind: 44 MW Solar PV: 110 MW	None
2	Portfolio with no GHG Target	Small ICE: 8 MW Large ICE: 162 MW	Wind: 44 MW Solar PV: 105 MW	None
3	Portfolio with no GHG Target	Small ICE: 8 MW Large ICE: 144 MW	Wind: 44 MW Solar PV: 135 MW	20 MW
4	Portfolio with Full GHG Compliance and Storage	Small ICE: 8 MW Large ICE: 145 MW	Wind: 28 MW Solar PV: 195 MW	125 MW
5	Portfolio with Full GHG Compliance and Storage	Small ICE: 22 MW Large ICE: 151 MW	Wind: 44 MW Solar PV: 135 MW	60 MW
6	Portfolio with Full GHG Compliance storage, and OTEC	Small ICE: 20 Large ICE: 126	Wind: 44 MW Solar PV: 90 MW OTEC: 12.5 MW	20 MW

Note: All portfolios have 70 MW of distributed solar, 5 MW of Municipal Solid Waste (MSW), and 1 MW of landfill gas.

Source: Pace Global analysis

As shown in Exhibit 31 portfolio compositions are a function of the constraints presented to each portfolio. The first and second portfolios build similar amounts of thermal capacity on an economic basis with no carbon goals imposed upon the portfolios. The third portfolio builds storage and less thermal capacity but the storage is able to accommodate more renewables and comes close to meeting the carbon goals in 2030, albeit shows violations beyond 2030. The fourth portfolio that meets the carbon constraint but with diesel fuel has to build significantly larger amounts of renewables and storage to meet the carbon emission goals. The fifth portfolio is the same as the fourth portfolio but with natural gas available on the island. In this portfolio, the renewables buildout is smaller and consequently less storage is needed to integrate the renewables and meet the carbon emission reduction target. The sixth portfolio partly replaces intermittent renewables with baseload renewables. As expected, in this portfolio, less storage is needed to integrate renewables and meet the carbon emission reduction goals. All portfolios include the waste-to-energy facility and the landfill gas facility.

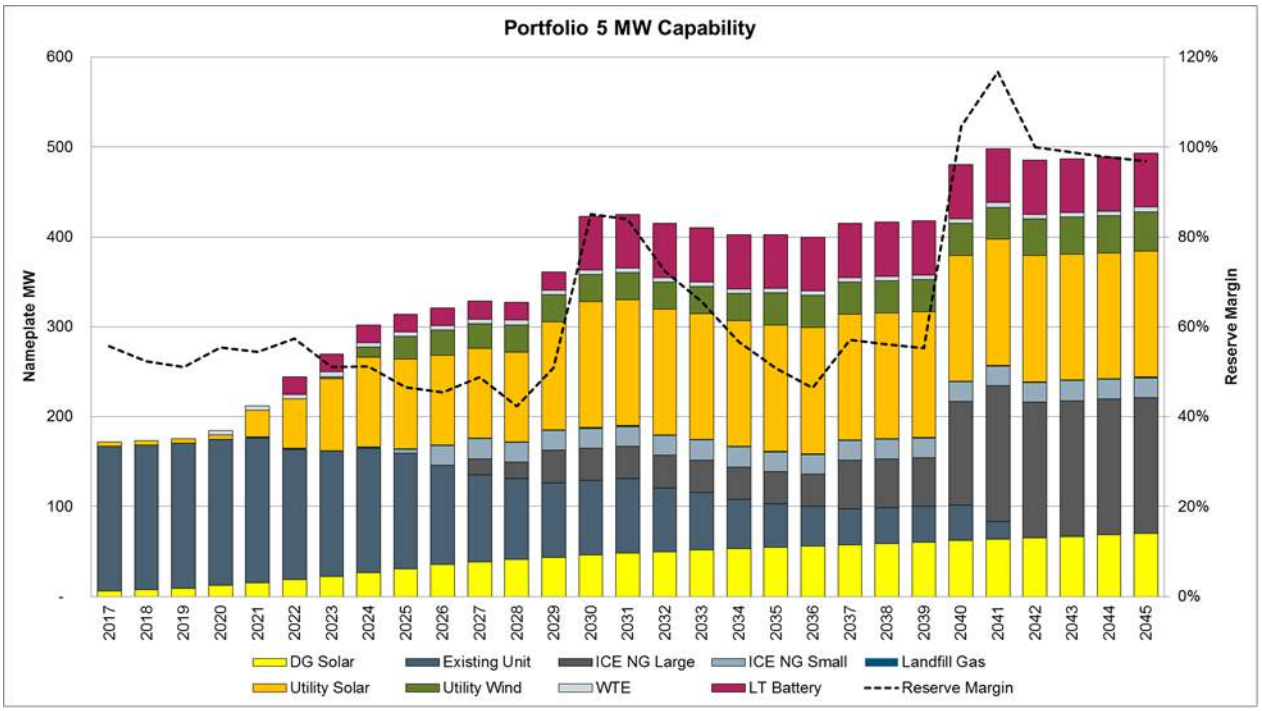
Exhibit 31: Portfolio Summary

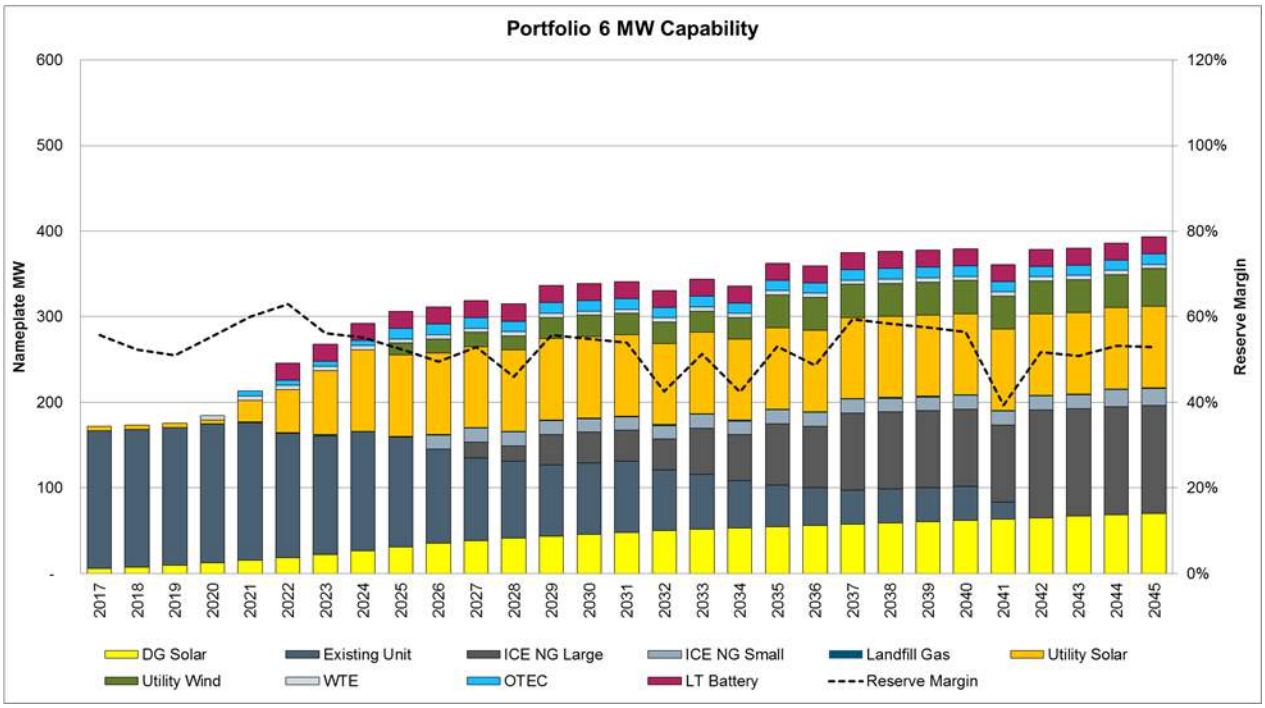
	P1: D-NS	P2: NG-NS	P3: NG-S
Fuel Assumption	Diesel	Natural Gas	Natural Gas
Thermal Builds	170 MW (2023-2041)	170 MW (2023-2042)	152 MW (2026 -2042)
Wind Builds	44 MW (2021-2024)	44 MW (2023 -2028)	44 MW (2021 -2029)
Utility Solar Builds	110 MW (2020-2035)	105 MW (2021-2042)	135 MW (2021-2035)
Distributed Solar	70 MW (2017-2045)	70 MW (2017-2045)	70 MW (2017-2045)
Battery Storage (Long Duration: 100%)	No	No	Yes, 20 MW Long Duration in 2022
Costs (Real$)	Total: $3.75 B; Fuel: $2.07 B; PV; $1.79 B	Total: $3.20 B; Fuel: $1.65 B; PV; $1.56 B	Total: $3.13 B; Fuel: $1.45 B; PV; $1.54 B
Emission Reduction by 2030 (thousand tons)	40% Reduction (443-268)	57% Reduction (443-192)	64% Reduction (443-158)*
Average Curtailments	14.22%	10.79%	6.80%
Av. Reserve Margins	48%	49%	50%
Ancillary Services	Spin, RegUp, RegDown carried by thermal	Spin, RegUp, RegDown carried by thermal	Batteries and Existing/New Thermal
Transmission Constraint (Limit: 70 MW)	None	None	0.42%

	P4: D-S-GHG	P5: NG-S-GHG	P6: NG-S-GHG-OTEC
Fuel Assumption	Diesel	Natural Gas	Natural Gas
Thermal Builds	153 MW (2032 - 2041)	173 MW (2025 - 2041)	146 MW (2026 - 2042)
Wind Builds	28 MW (2021 - 2040)	44 MW (2023 -2045)	44 MW (2025 -2045)
Utility Solar Builds	195 MW (2020 - 2045)	135 MW (2021 - 2030)	90 MW (2021 - 2024)
Distributed Solar	70 MW (2017-2045)	70 MW (2017-2045)	70 MW (2017-2045)
Battery Storage (Long Duration: 100%)	125 MW with 25 MW each in 2022, 2024, 2026, 2028, and 2030	20 MW 2022 and 40 MW in 2030	20 MW in 2022
Costs (Real$)	Total: $3.56 B; Fuel: $1.42 B; PV: $1.73 B	Total: $3.18 B; Fuel: $1.41 B; PV: $1.55 B	Total: $3.3 B; Fuel: $1.39 B; PV: $1.61 B
Emission Reduction by 2030 (thousand tons)	65% Reduction (443-153)	68% Reduction (443-140)	67% Reduction (443-146)
Average Curtailments	2.22%	2.99%	3.47%
Av. Reserve Margins	82%	55%	55%
Ancillary Services	Batteries and Existing/New Thermal	Batteries and Existing/New Thermal	Batteries and Existing/New Thermal
Transmission Constraint (Limit: 70 MW)	1.51%	0.29%	0.06%

Source: Pace Global analysis

Exhibit 32: Supply and Demand Balance for Integrated Portfolio Options

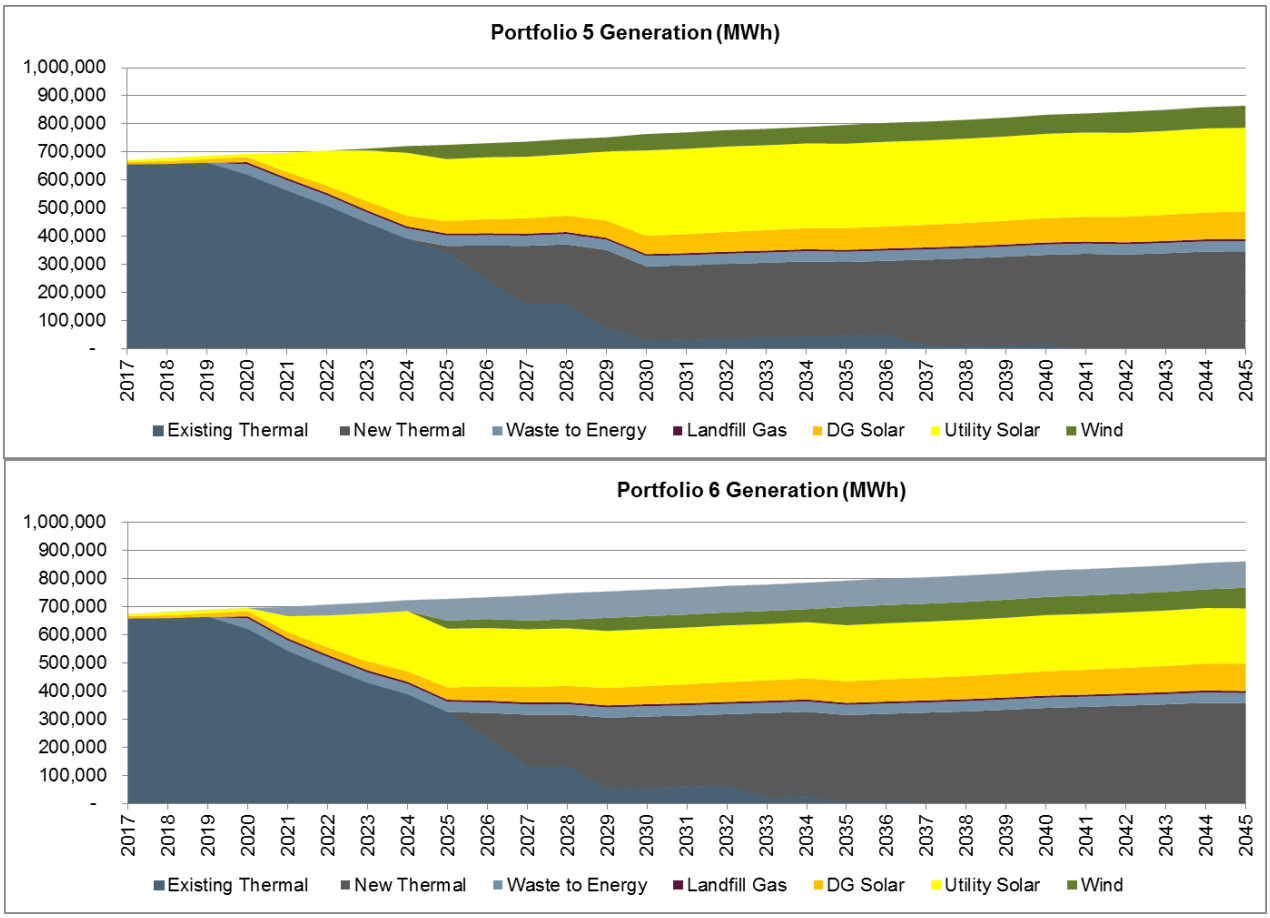




Source: Pace Global analysis.

Considering various portfolio attributes explained further in Chapter 8, Pace Global suggests that Portfolios 5 and 6 be the preferred options. Exhibit 32 shows the supply demand balance over time for the preferred portfolios while Exhibit 33 shows the energy mix over time. The portfolio buildout shows large amounts of solar and wind generation coming online in the early to middle period and thermal capacity coming online in the middle to late period to compensate for the retiring thermal resources and help support the ancillary service needs of the system. Nearly sixty percent of the energy mix is renewable by the 2030 compliance period inclusive of utility scale wind and solar, the municipal solid waste facility, the landfill gas facility, distributed solar, and the Ocean Thermal Energy Conversion (OTEC) facility in Portfolio 6.

Exhibit 33: Energy Needs and Resources for Integrated Portfolio Options



Source: Pace Global analysis.
Note that for Portfolio 5, the generation mix excludes the 61 MW of additional capacity needed to meet LOLE thresholds.

KEY PORTFOLIO RESPONSES

Exhibit 34 summarizes the responses to the key questions that the portfolios were conceptualized to answer. The responses quantify the benefits from a production cost standpoint. Other non-cost benefits are identified in the "Portfolio Analysis Results" chapter. As shown, the benefits from natural gas are approximately $230 MM largely associated with fuel cost savings net of differences in capital cost and

conversion costs associated with conversion to dual fuel capability. The value of storage is found to be very high. Storage was a key enabler in meeting the island's carbon emission reduction goals and achieved that at a lower cost. This is because of fuel price savings from higher levels of renewable energy relative to cost of storage. The analysis concluded that carbon goals cannot be met without storage given the hourly solar generation shape relative to the load profile.

The analysis also concluded that much higher levels of renewables and storage (60 MW and 65 MW respectively) are needed to comply with green house gas constraints if the island only had diesel vs. both diesel and natural gas. This is because of differences in diesel vs. gas emission rates. The larger amounts of capacity needed to meet the carbon goals comes with $176 MM higher costs. However, without the LOLE capacity addition, the portfolio cost differential is $160 MM.

Finally, the analysis showed that carbon emission reduction goals can be achieved via baseload renewables as well but at a $60 MM higher cost relative to intermittent renewables. The $60 MM cost differential is relative to portfolio 5 with the Loss of Load Equivalent (LOLE) adjustment[20]. Without the LOLE adjustments, the cost differential is approximately $80 MM.

However, as discussed in the portfolio analysis chapter, the value of baseload renewables can be captured in other metrics.

Exhibit 34: Portfolio Questions Answered

Relevant Question	Portfolio Addressed	Response
Should natural gas be considered an alternative fuel?	Portfolios 1 and 2	Yes, as portfolio costs are lower by $230 MM
What is the value of storage?	Portfolios 2 and 3	GHG target cannot be met without storage; Storage also helps lower portfolio costs by $20 MM
What is the cost of compliance with green-house gas emission targets?	Portfolios 2 and 5	Storage helps integrate renewables and meet carbon standards at a lower cost
How much more renewables and storage is needed with Diesel vs. Natural gas?	Portfolios 4 and 5	60 MW of additional solar and 65 MW of additional storage at a cost of $176 MM
What is the value of baseload renewables relative to intermittent renewable resources?	Portfolios 5 and 6	Portfolio costs are higher by $60 MM [1] but OTEC has other benefits

[1] Without the LOLE adjustment to P5, the cost differential is $80 MM.
[2] Without the LOLE adjustment to P4, the cost differential relative to P5 is $160 MM.
Source: Pace Global

[20] Please refer to Appendix for a complete description of the LOLE analysis.

CHAPTER 7: MARKETLINK SCENARIO DETAILS

MARKETLINK SCENARIOS

In order to evaluate the portfolios against a range of potential future conditions, Pace Global developed four distinct, but internally consistent scenarios within our MarketLink[21] process. The scenarios are designed around broad themes that stress the boundary conditions for many key drivers relevant to CUC's portfolio choices. The scenarios are defined as follows:

- Base Case: In the short-term (2016-2019), the Reference Case assumes a business-as-usual perspective for all market drivers. This Base Scenario assumes that in the U.S. CPP will not be scuttled but delayed. The scenario assumes moderate technological advance of wind and solar over time. Rising costs for diesel and natural gas prices over time.

- High Economy/Low Regulatory Case (: A robust and growing U.S. (and Island) economy that keeps upward pressure on all of the major market outcome categories, including load growth, and fuel costs. This growth is in the absence of a major technological breakthrough. While this scenario shares many of the attributes of the "High Technology" scenario, the pace of technological innovation is not as dynamic and therefore not beneficial to keeping prices and costs in check. High global demand growth will keep upward pressure on thermal capital costs relative to renewable capital costs.

- Low Economy/High Regulatory Case: Sluggish U.S. (and Island) economic growth both domestically and globally, including (in the short-term) in important growth markets like China, Europe, and Brazil. A combination of low economy and high regulations puts downward pressure on fuel prices, especially in the mid to long term, as renewables push out gas demand. Significant government intervention and regulations put upward pressure on renewable capital costs and lessen pressure on thermal capital costs over time.

- High Technology Case: A scenario based on the dominance of technological change in re-shaping the traditional electric utility model. Costs for solar PV and batteries decline faster than in the Reference Case, driving distributed solar penetration. Advancements in fracking technology keep natural gas and diesel prices low. Overall there are higher levels of energy efficiency and DG, which helps to mitigate the load growth that might otherwise be expected in a High Technology scenario. Storage breakthroughs in the mid-term, result in greater levels of renewable development without the need for back-up gas generation – reducing the effective cost of renewable generation.

There are four major portfolio cost drivers that vary across the MarketLink scenarios. These include commodity prices (diesel and natural gas), demand (gross demand and energy efficiency, capital costs (thermal & renewable) and, the amount of distributed solar PV penetration in the CUC service territory. Exhibit 35 summarizes how each of these variables changes across the three market scenarios in comparison to the Base Case, while the remainder of this section describes the underlying assumptions in more detail.

[21] MarketLink refers to Pace Global's corporate scenario development process, which identifies global and national "states-of-the-world" for use in resource and strategic planning.

Exhibit 35: MarketLink Summary of Key Variables vs. Reference Case across Scenarios

	Diesel Prices	Natural Gas Prices	Distributed Generation	Thermal Capital Costs	Renewable Capital Costs	Gross Demand	Energy Efficiency
Base	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Low Economy High Regulation	Moderate in medium term to low in long term	Moderate in medium term to low in long term	Low	Moderate in medium term to low in long term	Moderate in medium term to high in long term	Low	High
High Economy Low Regulation	High	High	Reference	Moderate in medium term to high in long term	Moderate	High	Low
High Technology (Transformation)	Low	Low	High	Moderate	Low	Moderate	Reference

Note: Higher costs assume +1 standard deviation from reference costs, low means -1 standard deviation relative to reference costs, moderate assumes the same as reference costs. Assumes short term: 2016-2019; Medium term: 2020-2025, and Long Term: 2026-2036. In short term, all scenarios assume the perspective as base scenario.

Source: Pace Global

As shown in Exhibit 35, for the IRP analysis, three alternative scenarios were considered, in addition to the Base case. The scenarios included the low economy case, the high economy case, and the high technology (transformation) case. Inputs for the key variables were developed to ensure that they were internally consistent with the scenario by first developing directional changes for each variable (load, gas prices, diesel prices, thermal capital costs, and renewable capital costs) relative to the base case forecast in the near, mid, and long term. Values were then selected for each scenario that reflect one standard deviation from the mean in the direction indicated, and in few limited cases a ½ standard deviation or other larger variation. In our experience, one standard deviation provides a reasonable boundary condition to assess the uncertainty associated with key variables in a deterministic modeling approach.

DIESEL PRICES

Diesel prices are a key driver of power markets and portfolio costs for CUC. Exhibit 36 summarizes the projected price trajectories for delivered diesel (ULSD) prices at Grand Cayman under the various scenarios, while the following section summarizes the key drivers for each.

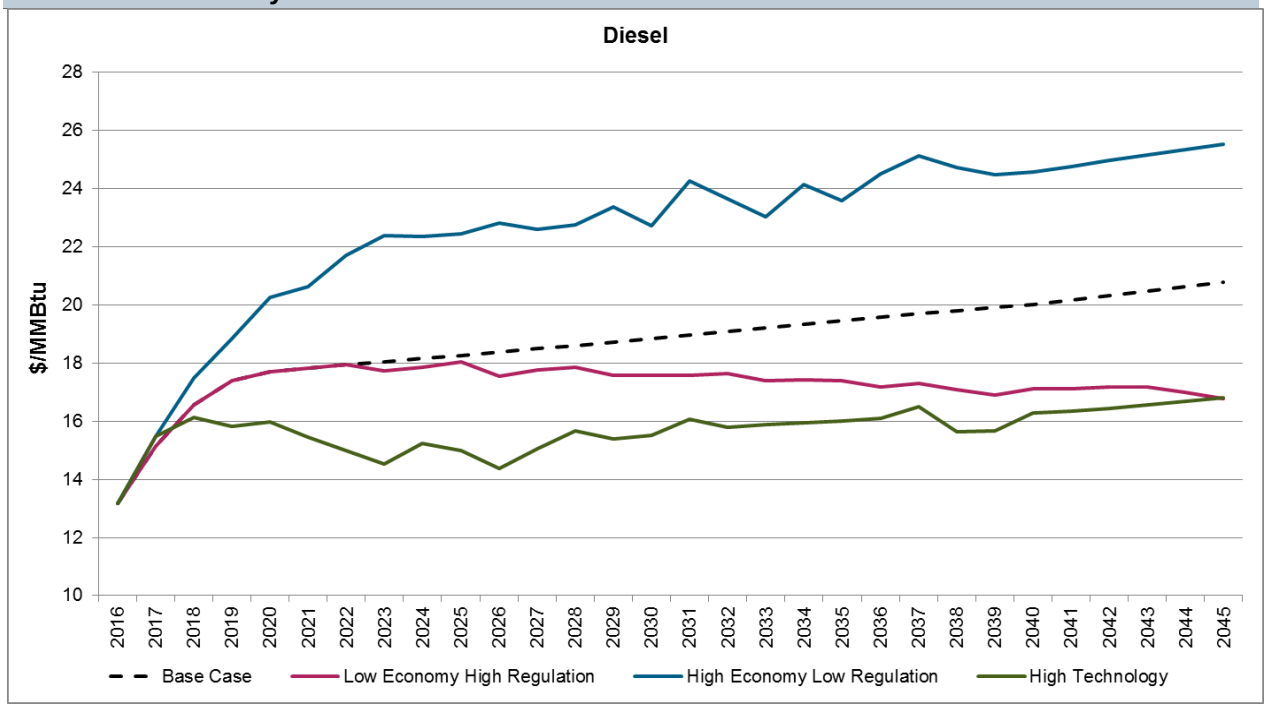
Under Pace Global's Reference Case outlook, the base commodity U.S. Gulf Coast diesel price is expected to continue to recover from a recent market low of $6.00/MMBtu ($0.83/gallon) in January 2016 to prices more in line with the historical average from 2010-2016 ($17.30/MMBtu). As mentioned in the Fuel Supply Analysis section earlier in this report, diesel prices are closely correlated with WTI crude oil prices, which serve as the basis for our base commodity diesel price forecast, with an additional $4.30/MMBtu in transportation costs from the Houston Ship Channel.

In terms of diesel prices delivered to Grand Cayman in the near term (2017-2018), diesel prices are

expected to remain relatively low, ranging from $15.00-17.00/MMBtu as U.S. production from new sources of shale oil coupled with a global crude oil oversupply continue to outpace global demand for oil products. In the mid- to long-term, crude oil prices are expected to rise over time from $17.50/MMBtu in 2019 to $21.00/MMBtu in 2045 as oil markets revert back to a more long-term sustainable balance of $60-80/barrel. OPEC, which represents approximately 43 percent of total global oil production, has moved to curtail some of its production, which will put upward pressure on oil prices (and thus diesel prices). But long-run economics for oil will continue to see a strong supply response from U.S. shale oil producers as prices rise toward $80/barrel, helping to keep a theoretical ceiling on our Reference Case prices.

Energy markets and crude oil in particular can be very volatile and it is therefore useful to establish upper price and lower price pathways relative to our Reference Case forecast. An upper price path for diesel prices would be more likely if diesel demand is higher in the power sector than in the Reference Case, as a result of high economic growth in OECD and non-OECD countries. Other economic conditions, such as surging demand for oil together with supply constraints, could help to push the outlook for diesel prices to one standard deviation or more above the Reference Case outlook, which is shown in the Exhibit 36 below. Conversely, an oversupplied global market coupled with flagging global demand, for example from a rapid decarbonization of economies or simply from advances in shale oil production technology and increases in shale oil reserves, could push prices downward by one standard deviation or more from the Reference Case outlook, also shown in the Exhibit 36 below.

Exhibit 36: Grand Cayman Delivered Diesel Prices



*Note that the High Technology scenario uses the Reference Case gas price projections.

Source: Pace Global

NATURAL GAS PRICES

Natural gas prices are a key driver of power markets and portfolio costs for CUC. Exhibit 37 summarizes the projected price trajectories for delivered natural gas prices at Grand Cayman in the Reference Case as well as one standard deviation above and below the Reference Case, while the following section

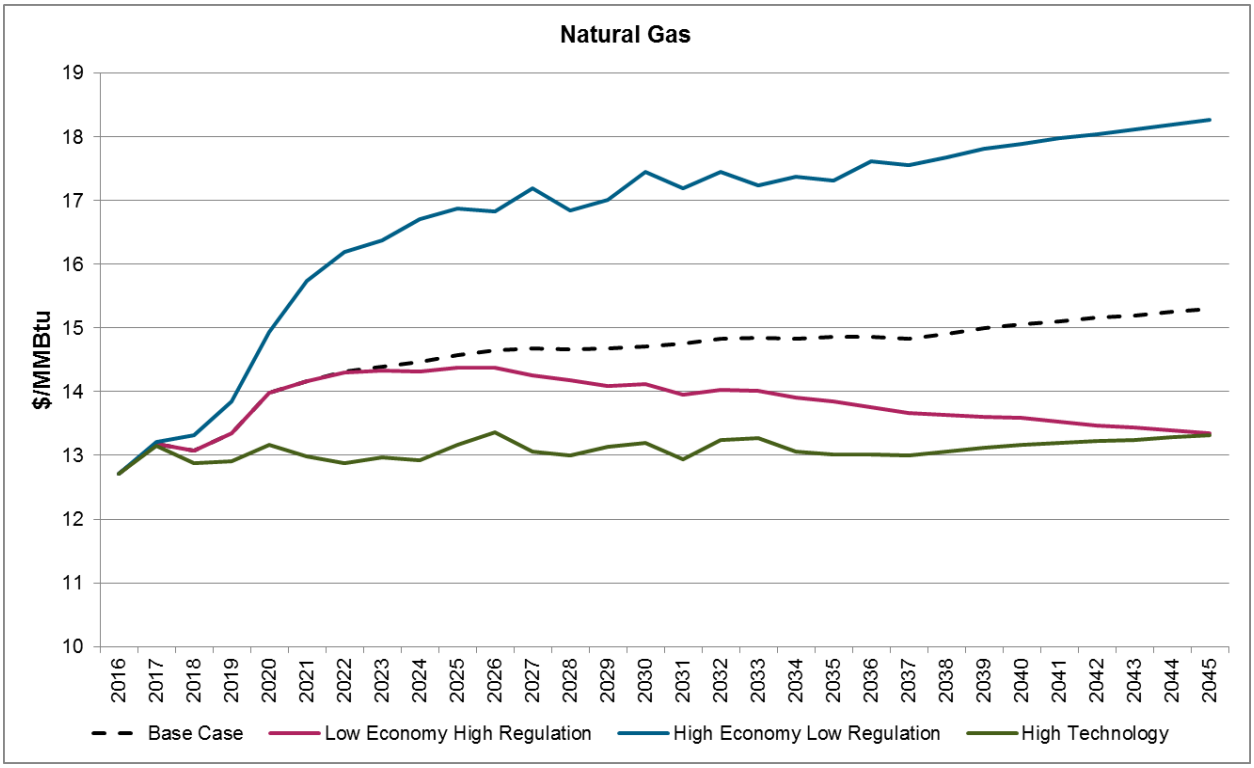
summarizes the key drivers for each.

Pace Global's Reference Case outlook for natural gas prices is based on the fundamental outlook supply, demand, and infrastructure in North America (and indirectly globally through LNG exports). At the benchmark Henry Hub, natural gas prices have been driven downward since the onset of shale gas production, reaching a recent historic low of $1.50/MMBtu in March 2016. However, such a low price is unsustainable in the long-run for producers who need to make a reasonable return on investment, and prices are expected to revert toward the historical average from 2010-2016 of $3.50/MMBtu.

In terms of natural gas prices delivered to Grand Cayman (in the form of LNG), the short-term outlook (2017-2018) sees prices remaining at or very near $13.00/MMBtu, inclusive of approximately $10.00/MMBtu in liquefaction, transportation, and island costs. The U.S. remains well supplied with natural gas, despite a decline from a peak production level of 75 Bcf/d in 2016 to 71 Bcf/d in 2017 as producers pull back on production in the face of sustained (2+ years) low prices. There is a substantial inventory of Drilled-but-Uncompleted wells that can be brought online relatively inexpensively to help keep natural gas prices in the U.S. in check in the short-term. In the medium-term, Henry Hub prices are expected to rise as new demand (mostly LNG exports and pipeline exports to Mexico but also from the industrial and power generation sectors) increases to take advantage of relatively low prices and to mop up surplus natural gas supply. In the long-term, delivered natural gas prices are expected to be limited to approximately $15.00/MMBtu as both shale and conventional natural gas reserves become broadly economically feasible to produce at $5.00/MMBtu at the Henry Hub.

As with oil markets, natural gas markets can also be volatile. A view of upper and lower price path trajectories based on standard deviations is useful for understanding exposure to price risk. Average natural gas prices could in theory rise to one standard deviation above the Reference Case outlook if markets experience supply constraints, surging demand, and infrastructure that is unable to efficiently deliver natural gas from producing to consuming regions. Conversely, low natural gas prices to Grand Cayman could in theory levelize at $10.00/MMBtu if markets remain chronically oversupplied, demand fails to materialize in a significant way, and if oil prices also remain significantly lower than the Reference Case outlook for that commodity.

Exhibit 37: Grand Cayman Delivered Natural Gas Prices by Scenario



*Note that the High Technology scenario uses the Reference Case gas price projections.
Source: Pace Global

DISTRIBUTED SOLAR PV PENETRATION

Distributed solar penetration is a significant driver of CUC's portfolio cost profile over the long term. Residential and commercial adoption of solar PV can impact the operations of CUC's remaining fleet and affect the costs borne by remaining customers. Exhibit 38 summarizes the projected solar PV penetration levels in MW under the various scenarios, while the following section summarizes the key drivers for each.

Pace Global's Reference Case is based on an analysis of expected avoided costs, trajectories for capital costs for solar, and the expected penetration rates that are associated with the resulting payback periods for residential and commercial customers.

Appendix II: Solar Penetration Analysis provides additional detail on the methodology, analysis, and results, summarizing that the expectation in the Reference Case is for around 70 MW of solar PV by the 2040s. Note that the theoretical limit of DG solar penetration is currently 65 MW due to reverse power issues[22].

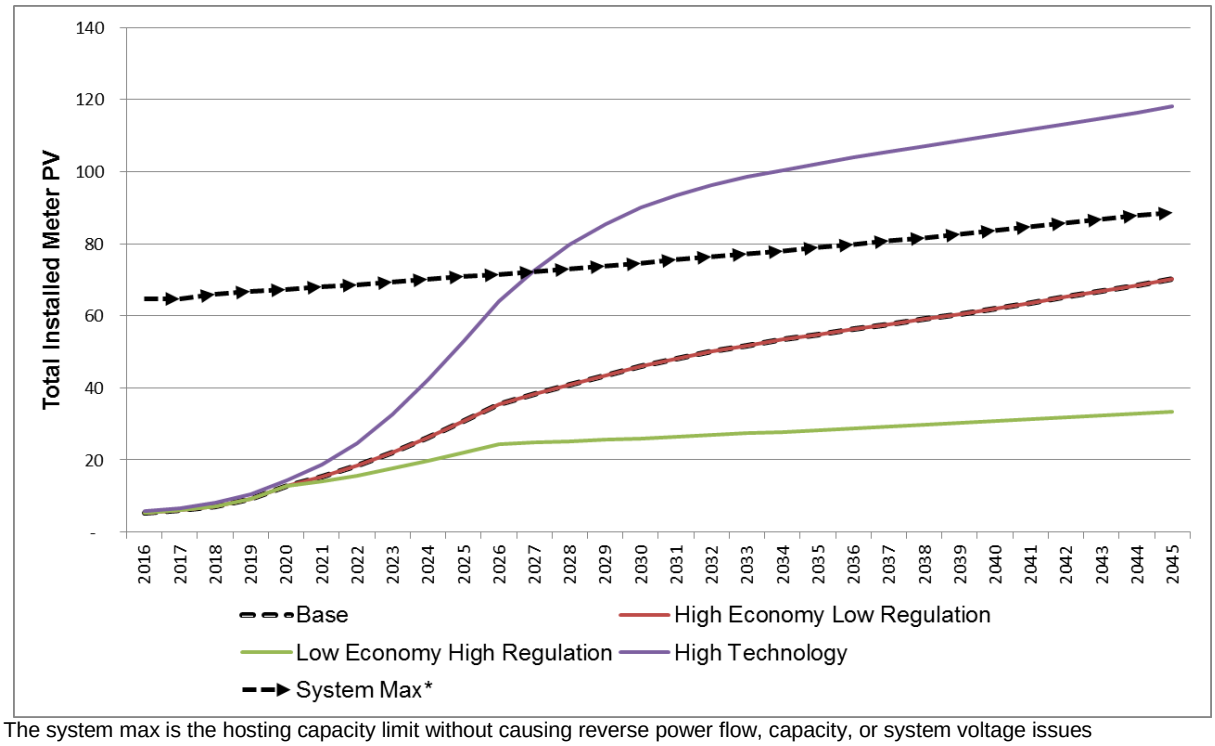
Under the High Technology scenario, a combination of technology drivers and customer preferences lead to a higher penetration rate over time. Faster-than-expected declines in capital costs drive improved economics. Further, new market players and information platforms spread the potential opportunities to more customers. Overall, under this scenario, the payback period for most customers improves to five years (vs. an average of seven years in the Reference Case), and the capacity of new distributed solar PV

[22] As determined by the Renewable Infusion Study Report prepared by Leidos in October 2015. The solar penetration study assumes a 1% year on year increase in the limit over the forecast horizon.

installations increases towards 118 MW by 2045. However, given the DG penetration is limited to 89 MW due to the system limit described above.

Under the Low Economy scenario, costs of electricity are lower than the Reference Case due to flat natural gas and CO_2 prices. Furthermore, distributed PV solar costs stay above the Reference case in the long term As a result, the expected payback period for new solar PV installations increases to ten years, driving a much more gradual penetration rate. Overall, by 2045, the total capacity of solar PV installations in CUC is only around 34 MW.

Exhibit 38: CUC Distributed Solar PV Penetration Levels by Scenario



* The system max is the hosting capacity limit without causing reverse power flow, capacity, or system voltage issues

Source: Pace Global

CAPITAL COSTS

Capital costs can be a key driver of power markets and portfolio costs for CUC. Exhibit 39 summarizes the projected price trajectories for thermal and renewable capital costs for Grand Cayman under the various scenarios, while the following section summarizes the key drivers for each.

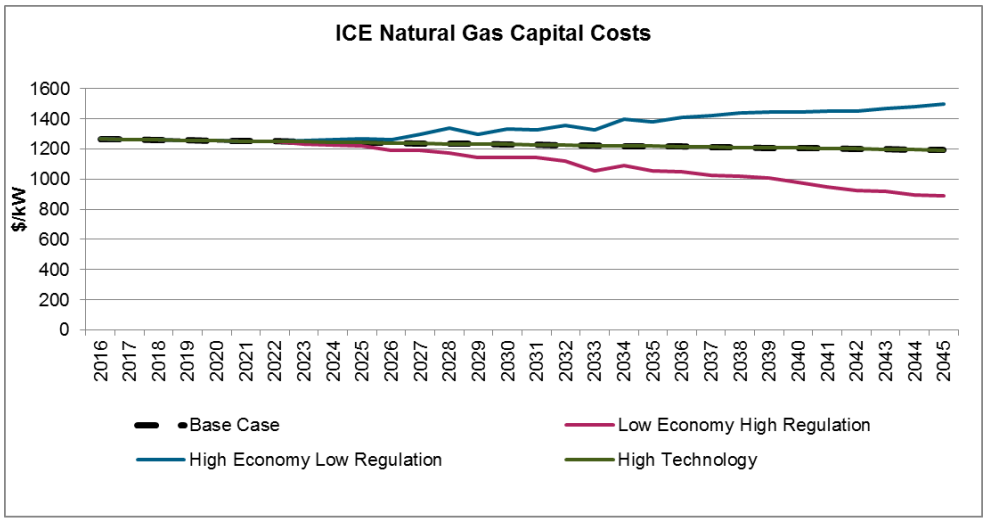
Under Pace Global's Reference Case outlook, thermal capital costs show progressive declines over time but the rate of decline is not as great as the decline in renewable capital costs. Siemens PTI maintains a database of applicable studies, projects, and announcements that include over fifty public and confidential client sources. All sources in the database are within three years of the present to maintain up-to-date assumptions. The Siemens PTI team screens each source for equipment type, model, project scope and location to develop qualified samples. These qualified samples are then modified using variables including location adjustments, inflation adjustments and owner's interest rate to develop comparable national samples. Siemens PTI then uses statistical analysis from the comparable national samples and expert opinion to determine likely cost ranges for each technology. The technology database provides the

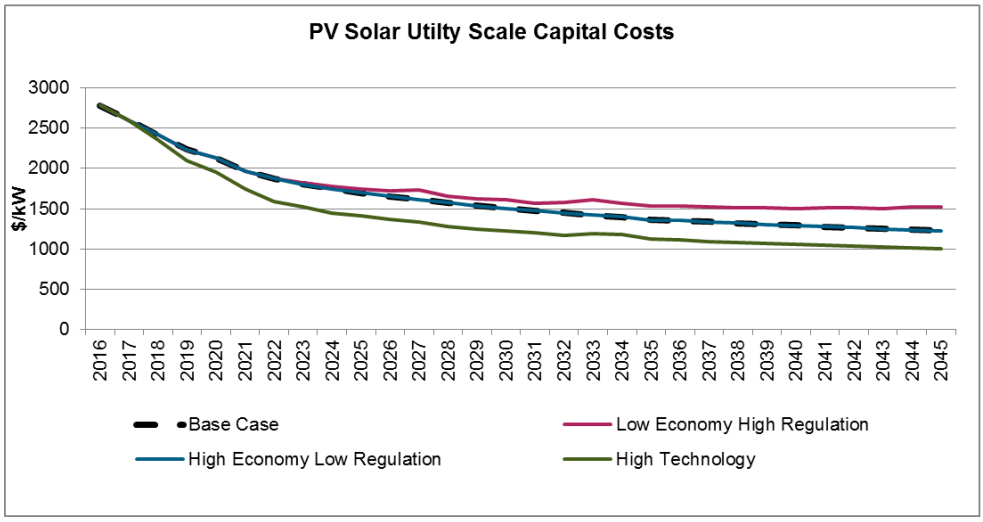
foundation for our technology performance and costs forecasts. To develop longer term cost projections, a number of other factors are considered, including the recent and expected rates of technological improvements for existing technologies and new technologies that are under development. The analysis was conducted using U.S costs as reference and then using specific project experience in the Caribbean and interviews with developers.

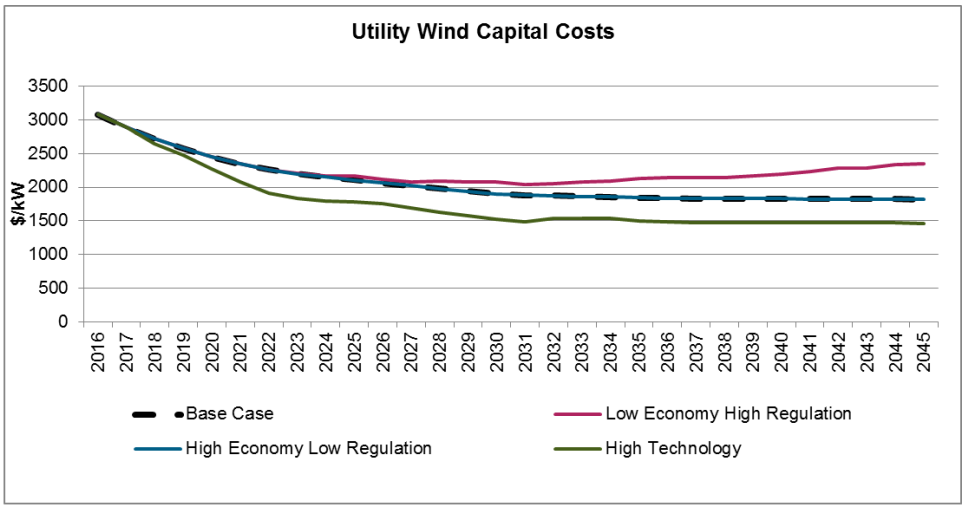
Under the High Economy scenario, thermal capital costs follow the same pattern as in the Reference case but become higher than base case in the long term. Renewable capital costs follow the Reference case in both the medium to long term.

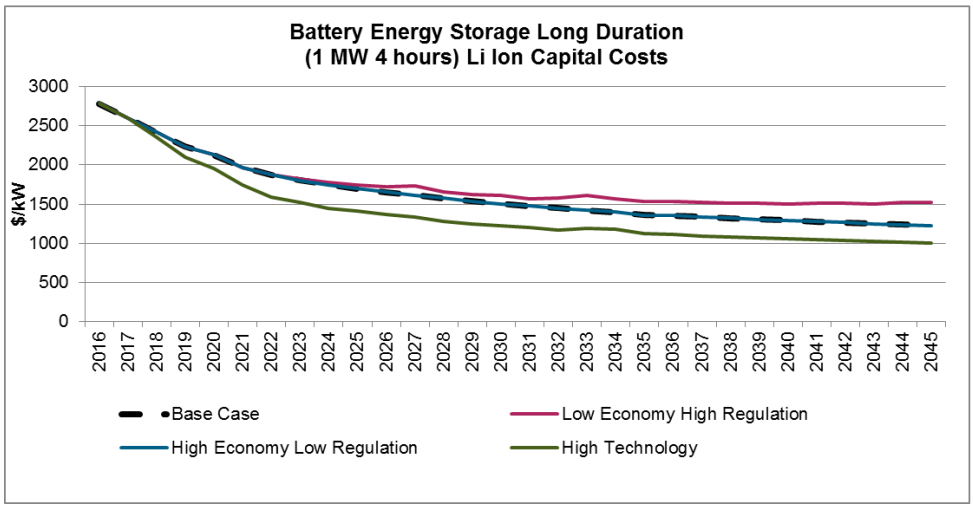
Under Low Economy scenario, thermal capital costs follow the same pattern as in the Reference case but become lower than base case in the long term. Renewable capital costs are moderate in the medium term but become higher than the reference case in the long term.

Exhibit 39: Capital Costs by Scenario for Renewable and Thermal technology









Source: Pace Global

CUC LOAD GROWTH

Projections for load growth rates, load factors (the ratio between average and peak load), and hourly load profiles are all important drivers of CUC's portfolio costs. These variables change in the different MarketLink scenarios, with summary differences presented in Exhibit 40 and in the section below.

Pace Global's Reference Case load forecast was developed based on an econometric analysis of key economic and weather drivers, along with incorporation of customer count trajectories, energy efficiency and electric vehicle penetration over time. The details are explained in Appendix III: Load Forecast Details. The gross demand forecast leads to a compound annual growth rate (CAGR) of 1.76% for average demand and 1.56% for peak demand growth rate. The Reference case assumes that over the next 21 years (2037), there will be a 16% reduction in demand relative to the base gross demand due to economically viable energy efficiency investments. This is based on the "Medium EE" case where-in 50% of economically

viable energy efficient investments are made[23]. With this adjustment, the net average demand growth rate is 0.87% and net peak demand growth rate is 0.67%.

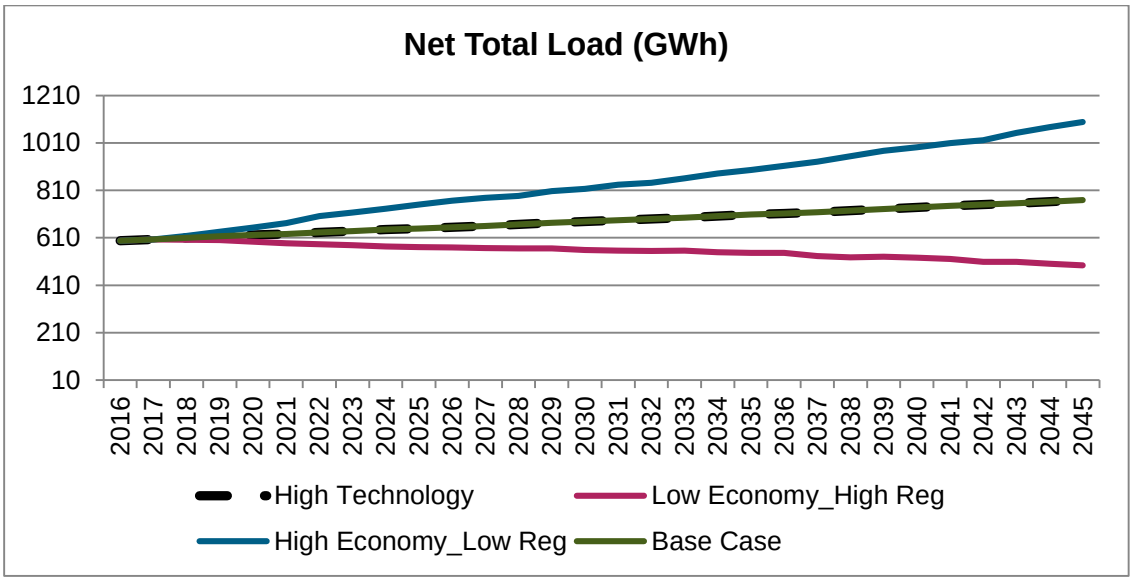
Under the High Economy scenario, the gross demand growth rate is expected to be higher due to higher US economic growth rate and consequently higher growth rate in the Grand Cayman due to higher growth in stayover tourism and financial sectors. Under this scenario, the average demand growth rate is 2.14% and peak demand growth rate is 1.90%. The energy efficiency growth and penetration is assumed to be lower relative to the Reference case as general feeling of well-being leads to very little investment on the part of the utility and the customer to invest in energy efficiency.

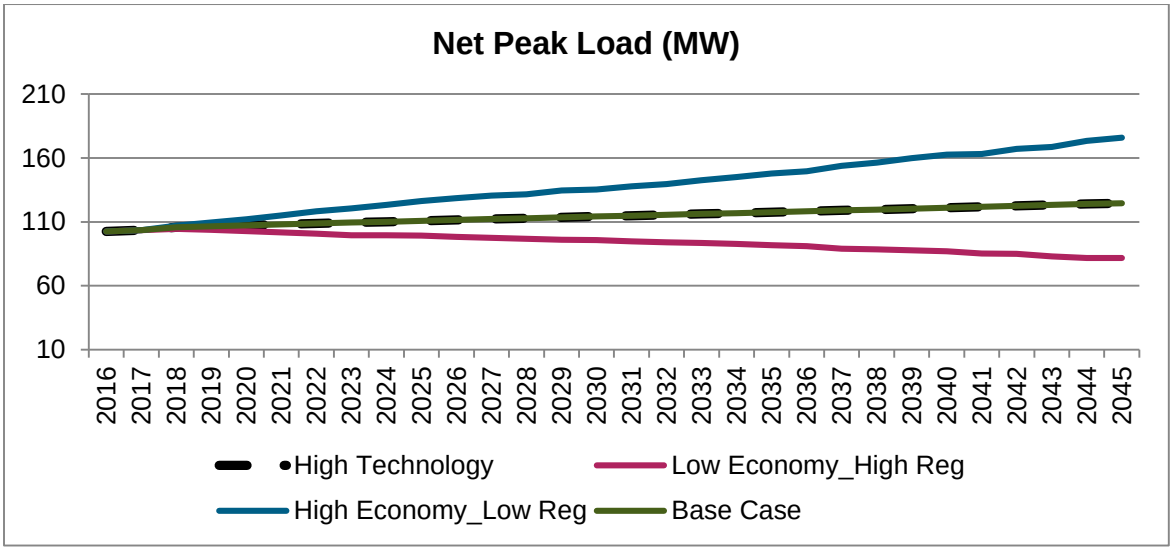
Under the low economy scenario, the gross demand growth rate is lower than Reference case demand reflecting lackluster economic growth due to a slowdown in world economy. The low economy case assumes that over the next 21 years (2037), there will be a 33% reduction in demand relative to the base gross demand due to economically viable energy efficiency investments. This is based on the Full EE case where-in 100% of economically viable energy efficient investments are made. It is assumed that the low economic growth environmental will compel utilities and customers to make longer term investments in energy efficient technologies. This overall results in negative demand growth rate over the forecast horizon. (-0.66% for average and -0.78% for peak).

The gross demand growth rate in the High Technology scenario is assumed to be the same as the reference case. The energy efficiency assumptions are also the same as the reference case. Pace Global recognizes that in this scenario, higher than expected penetration of Plug-in hybrid electric vehicles can alter the load shape and change the average to peak demand ratio. However, specific adjustment has not been made in the analysis. Furthermore, shifting from peak to off-peak consumption can occur if there is effective deployment of time-of-use rates using CUC's existing advanced metering infrastructure.

[23] Based on the Castelia Strategic Advisors report to the National Energy Policy Review Committee, Nov 2016.

Exhibit 40: CUC Load Growth Projections by Scenario





*Note that the High Technology scenario uses the Reference Case demand levels

Source: Pace Global

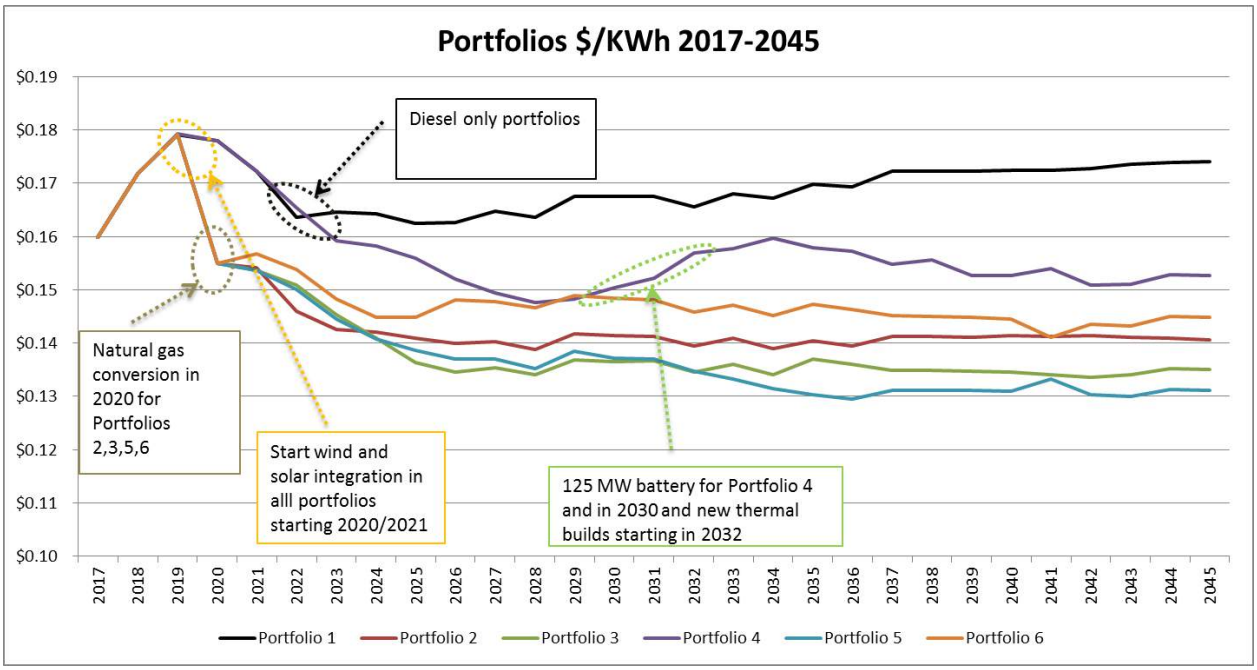
CHAPTER 8: PORTFOLIO ANALYSIS RESULTS

REFERENCE CASE PORTFOLIO ANALYSIS – COST ASSESSMENT

Each of the integrated portfolios was analyzed through the hourly dispatch simulation methodology. This analysis incorporated all existing resources and contracts (see Exhibit 11), expectations for CUC's future hourly loads (see Appendix III: Load Forecast Details), as well as expectations for distributed solar additions installed by customers (See Appendix II). The IRP analysis assesses the total costs of CUC's generation over time for each portfolio option, with the key findings summarized in Exhibit 41.

Overall, the cost analysis indicates that Portfolio 1 with diesel and no storage is highest cost due to significant spending on maintenance capital and operations, high exposure to the market as units are expected to fail, and high value of lost load ("VOLL") costs as a result of expected outage events (see APPENDIX I: Loss of Load Equivalent Analysis). The lowest cost portfolio option is Portfolio 5, driven primarily by the ability to use a combination of natural gas and renewables to achieve emission targets. Storage also plays a critical role in enabling integration of a larger amount of renewable resources and helps meet the emission targets. For additional detail on annual costs, please refer to Appendix VI.

Exhibit 41: Annual Portfolio Cost Projections – Reference Case



Source: Pace Global analysis.
Note that for Portfolio 4 and 5, the cost projections exclude the additional capacity needed to meet LOLE thresholds.

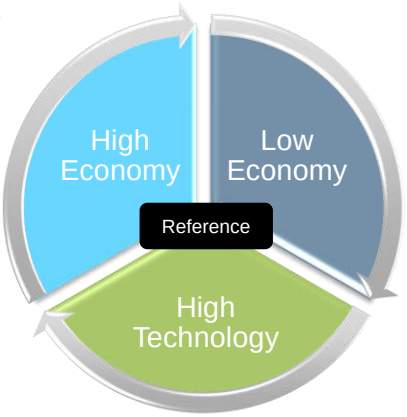
Each of the integrated portfolios was evaluated against each of the MarketLink scenarios as summarized in Exhibit 42 [24]in order to assess the impact of changes in key external drivers on overall portfolio costs. Exhibit 43 summarizes the results of this analysis by plotting the levelized costs of each portfolio across the

[24] A comprehensive description of the Marketlink scenarios is provided in Chapter 7.

30-year evaluation period for each of the four market scenarios. While Portfolio 5 is the lowest cost portfolio, Portfolio 3 appears to have the lowest risk.

Exhibit 42: MarketLink Scenario Summary

Robust US and island economy driving electricity demand growth
Upward pressure on fuel prices



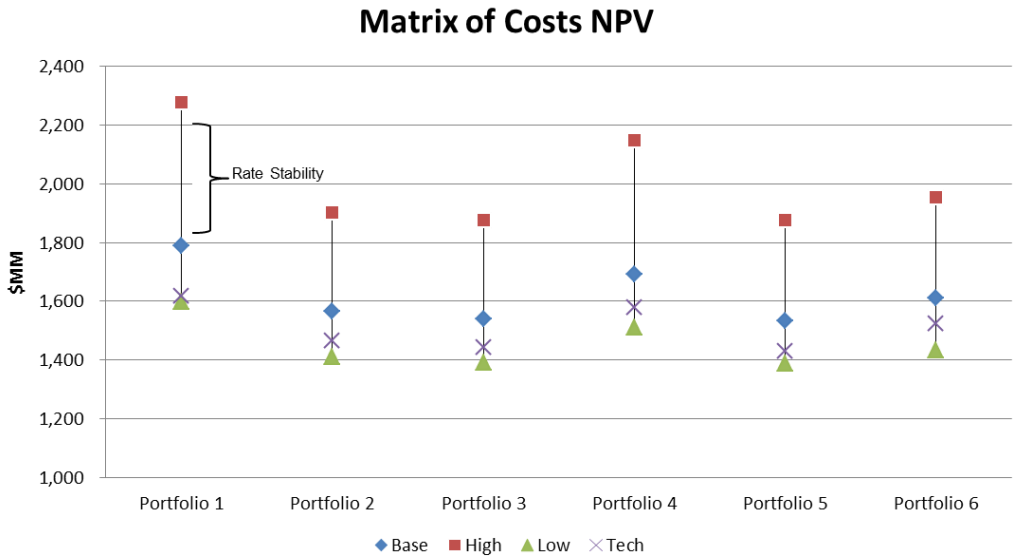
Sluggish US and island economy puts downward pressure on load growth, downward pressure on fuel prices in the mid to long term due to poor economic growth and high regulations

High solar PV due to rapidly declining costs of solar PV and batteries
Advancements in fracking keep fuel prices low

Source: Pace Global

The portfolios with diesel – Portfolios 1 and 4 – have the highest risk given the price volatility associated with diesel. In general portfolios with natural gas, storage, and renewables are the lowest cost and also show the lowest risk. Portfolio 6 with OTEC also fares well in the risk spectrum given the certainty in pricing associated with a PPA. In other words, part of the capital cost uncertainty goes away with the OTEC PPA.

Exhibit 43: Summary of Levelized Portfolio Costs across MarketLink Scenarios



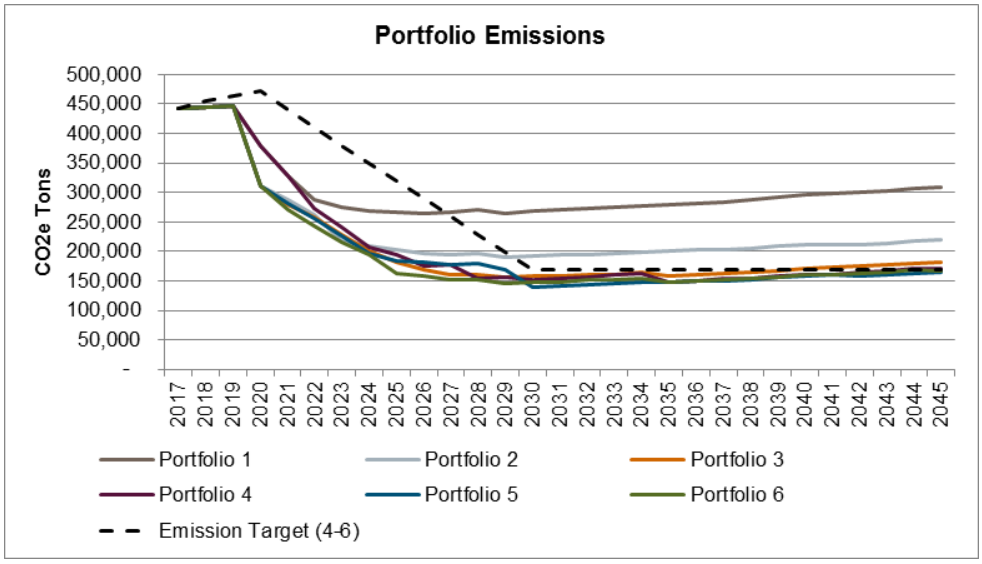
The WACC is assumed to be 7.87% nominal, 5.5% real.

Source: Pace Global

ENVIRONMENTAL STEWARDSHIP ASSESSMENT

The portfolio analysis evaluated one key metric for environmental stewardship –CO_2 emissions reduction goal. Three portfolios were constructed to meet the carbon emission reduction goal while the other three portfolios were designed to estimate the degree of renewable penetration growth due to economic drivers with no carbon emission reduction goal. Portfolios with natural gas, intermittent renewables, and storage were able to comply at the lowest cost, followed by portfolios with OTEC and natural gas. Portfolio with diesel, renewables, and storage had the highest cost because diesel burns less cleanly than natural gas and consequently requires much larger amounts or renewables and storage to meet carbon goals relative to the portfolios with natural gas.

Exhibit 44: Portfolio CO_{2e} Emissions



Source: Pace Global

DIVERSITY

The Diversity metric in Exhibit 45 contains two sub-metrics (2030 concentration and number of technologies) to form this major metric used in the portfolio ranking. The 2030 concentration metric is the largest technology percent of generation compared to the total generation. The lower the percent concentration the more diverse the portfolio is. All the portfolios rely on thermal as the largest generating technology in 2030 except for portfolio 4 which needs a large amount of solar to meet the emissions constraints by 2030. For the number of technologies, Portfolio 6 does the best with dual fuel (gas and diesel) counting as two technologies and then, wind, solar, waste to energy, landfill gas, battery and OTEC.

Exhibit 45: Diversity Metrics

	2030 Concentration % reliance on largest technology MWh	Largest Technology MWh	Balance Energy Metric (# of technologies)
P1: D-NS	53%	Thermal	5 (Thermal: Diesel Only, Wind, Solar, Waste-to-Energy (WTE), landfill gas (LG)
P2: NG-NS	54%	Thermal	6 (Dual Fuel: Thermal, Wind, Solar, WTE, LG)
P3: NG-S	44%	Thermal	7 (Dual Fuel: Thermal, Wind, Solar, WTE, LG, Battery
P4: D-S-GHG	59%	Solar	6 (Thermal: Diesel Only, Wind, Solar, WTE, LG, Battery
P5: NG-S-GHG	48%	Thermal	7 (Dual Fuel: Thermal, Wind, Solar, WTE, LG, Battery
P6: NG-S-GHG-OTEC	41%	Thermal	8 (Dual Fuel: Thermal, Wind, Solar, WTE, LG, Battery, OTEC)

Source: Pace Global

LAND USE

All portfolios require large amounts of land use due to the proposed wind and solar buildout. There are many more studies and permitting issues to be addressed. Pace Global used generic assumptions based on acreage per MW for each technology. Utility scale solar was 5.5 acres/MW; Wind: 30 acres/MW; OTEC: 2 acres/MW, and storage 1 acre/MW. Portfolio 6 does the best on land use because of the two OTEC units modeled which decreased the overall solar usage needed in the portfolio.

Exhibit 46: Land Use

	Land Use (Total Acres)
P1: D-NS	1,925
P2: NG-NS	1,898
P3: NG-S	2,083
P4: D-S-GHG	2,038
P5: NG-S-GHG	2,123
P6: NG-S-GHG-OTEC	1,875

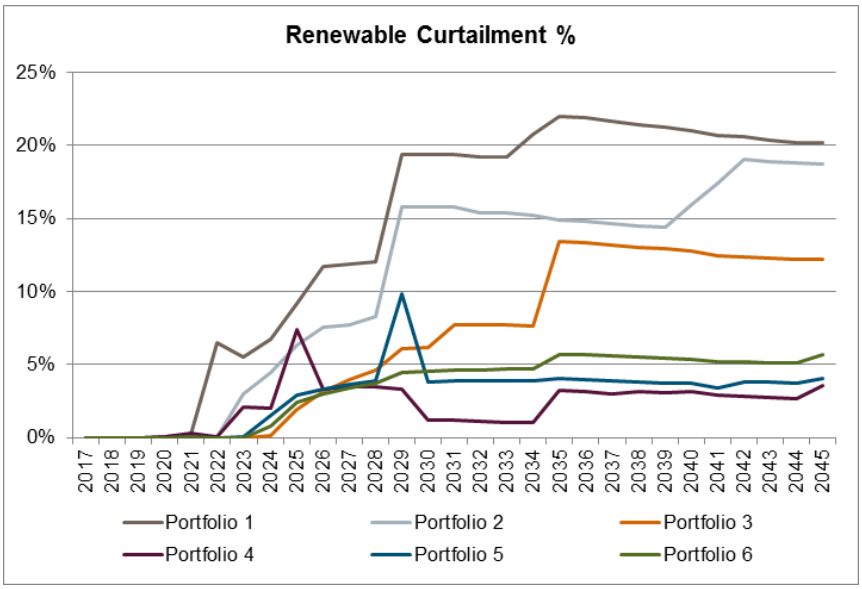
Source: Pace Global

CURTAILMENT ASSESSMENT

As part of the integrated portfolio analysis, utility scale solar and wind plant curtailments were estimated. The modeling framework would curtail generation if there was surplus energy outside of what can be handled by the system. Distributed solar generation resources were prohibited from being curtailed as currently there is no way for the utility to control output of the generation resources and no tariff mechanism is in place to compensate customers to reduce or curtail output. The analysis supports the use of battery

energy storage to reduce instances of curtailment and facilitate attainment of carbon emission reduction goals.

Exhibit 47: Portfolio Renewable Curtailment

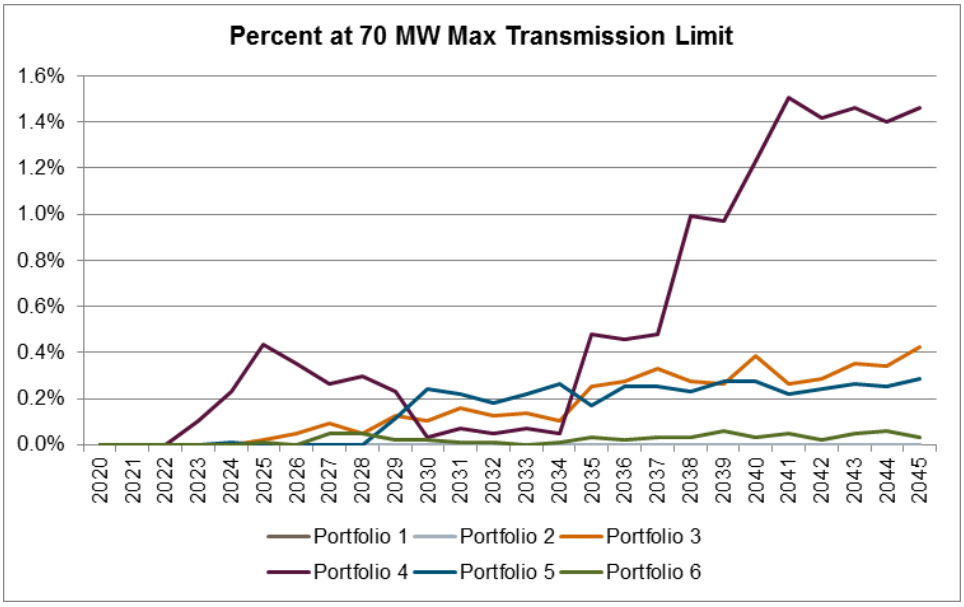


Source: Pace Global

TRANSMISSION AND GRID ASSESSMENT

As part of the integrated portfolio analysis, a high level grid assessment was performed. The grid analysis evaluated the need for reactive power compensation and thermal upgrades on the system. In most portfolios, the East to West transfer limits are not violated in the Reference Case. However, in the high demand scenario, the East-West transfers are expected to be higher and the transmission lines may have to be upgraded.

Exhibit 48: Transmission Flows



Source: Pace Global

Further, the analysis identified a need for reactive power compensation in the high demand scenario outside of what conventional thermal generation can supply (See Exhibit 49). This reactive power can be supplied via smart inverters connected to the storage and intermittent renewable resources, or through external capacitor banks strategically located on the transmission and/or distribution system. The analysis concluded that no additional compensation needs to be provided outside of what can be provided by thermal generation resources and through smart inverter controls connected to renewable and storage resources. As compensation is not required in the high demand case where reactive power needs are greater, it was concluded that no compensation is required in the base case. Reactive power compensation and optimization can be performed once the exact location of renewable resources is determined. The analysis assumed a load power factor of 95%, thermal reactive power capability of 80%, and renewable reactive power capability of 90%.

Exhibit 49: Reactive Compensation

	Reactive Power Need (MVAR)		Reactive Power Availability (MVAR)	
	2020	**2040**	**2020**	**2040**
Portfolio 1	30.4	44	56	59
Portfolio 4	30.4	46	56	49.75
Portfolio 6	30.4	56	62.4	82

Source: Pace Global

LOSS OF LOAD ANALYSIS – RELIABILITY ASSESSMENT

All of the metrics discussed above were considered as objectives. However, loss of load analysis or reliability analysis was considered as a constraint with all portfolios meeting the reliability criteria.

Separate from the hourly portfolio simulation analysis, the loss of load analysis was designed to assess the likelihood that CUC's generation and transmission system will be unable to meet load for any period of time. The objective of the analysis is to identify hours in which supply may be inadequate to meet demand. The analysis is performed using a Monte-Carlo analysis approach looking at 500 different combinations of supply and demand. For a more comprehensive description of the methodology, please review APPENDIX I: Loss of Load Equivalent Analysis.

The analysis concluded that Portfolios with smaller share of thermal resources fail to meet the LOLE standard of violations being no greater than 2.4 hours a year. Portfolio 4 with large amounts of storage and fewer thermal resources (98 MW relative to 130-160 on average for other portfolios) fails to meet the LOLE standard in two of the three test years. Portfolio 5 with the second largest amount of storage and 130 MW of thermal resources fails to meet the standard in one test year.

However, when the violations in Portfolios 4 and 5 are addressed through additional thermal resources, the portfolios fall back in compliance. Approximately 60 MW of additional thermal capacity was required to address the violations at a cost of $1393/kW Portfolio 4 and $1205/kW for Portfolio 5. The costs are in present value terms with differences in costs attributed to the timing when additional capacity is required. As capacity is needed in 2029 for Portfolio 4 vs. 2040 for Portfolio 5, costs are lower for Portfolio 5.

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SUMMARY OF PORTFOLIO ANALYSIS FINDINGS

The overall findings from the integrated portfolio analysis can be summarized according to each key metric. Exhibit 50 presents the details within each category along with a qualitative ranking of overall performance (green: positive; yellow: neutral; red: negative). The rankings have been developed using the raw scores for each category and then using proportional rankings to derive scaled scores between 1 and 10 with 1 being the best and 10 the worst. To arrive at the color rankings, a scaled score of 0-2 receives a green; 0-4: a green-yellow; 4-6: yellow; 6-8: yellow-red; and 8-10: red. To develop the summary ranking, cost was weighted at 60% of the overall score and each non-cost metric was assigned equal weight[25] from the remaining 40%. In other words, a simple average was used for the non-price weightings which was added to the cost weighting to develop the summary average rankings. The weighting methodology was discussed at the final stakeholder meetings but no clear mandate on weighting came out. In exercising its functions under the Electricity Sector Regulation Law (2018 Revision) namely, its duty to protect the economic interests of consumers by keeping electricity rates as low as reasonably possible and while keeping with industry best practices, OfReg has indicated a preference for cost to drive the rankings to a large extent and CUC supports this preference.

It should be noted that the weighting methodology for scored attributes for long term portfolios is different from the weighting methodology that would be applied on a project by project basis. The IRP is intended to develop a strategic direction for the Cayman Islands electricity sector to move in, with indicative proportions of energy sources to be developed. It therefore considers country level holistic issues such as land use and energy diversity. However, from an individual project standpoint, the applied weightings can be very different from the IRP weightings. For example, when new generation plant using a particular technology (solar, wind, OTEC, gas etc.) is called for, issues such as land use and energy diversity may have already been considered at the IRP level and through planning processes. For this reason and also with the aim of keeping electricity costs as low as possible in the face of generally higher costs in small island systems, individual projects would be expected to have higher weighting given to pricing attributes compared to non-price attributes than the IRP scoring.

The chosen weighting methodology recognizes electricity cost of production as the most significant factor

[25] Note that diversity metric included two sub-metrics (generation based share and number of technology options) while the "supplemental" metric included both land use and renewable curtailment with equal weights assigned to the two-categories in each case.

that outweighs all other factors. This is similar to the weighting that would likely be used during a renewable generation Request for Proposals (RfP) process. At the RfP stage, cost including risk (which is calculated as a contingent cost) is typically weighted in the 60% to 80% range and other metrics such as quality of the anticipated outcome and timeliness are introduced into the remaining scoring.

This scoring methodology has a weakness in that options that are not compliant with government greenhouse gas policy could achieve the best score. Those options that are not compliant should therefore be set aside in the analysis, however they are useful for comparison purposes. For example the cost difference between Portfolio 3 and Portfolio 5 (which is the cost of modifying Portfolio 3 to achieve greenhouse gas compliance) is highlighted through this methodology. This scoring methodology results in the greenhouse gas compliant natural gas option with storage (Portfolio 5) as the preferred portfolio followed by the OTEC portfolio (Portfolio 6).

Exhibit 50: Summary of Integrated Portfolio Results – All Metrics

Portfolio Construct	Cost (NPV of total costs) ($MM) with LOLE adjustment	Rate Stability $MM (Range High – Base NPV)	2030 Environmental Stewardship (Emission Reduction Target 60%)	Diversity Summary (see diversity slides)	Supplemental: Land Use (Total Acres) and Renewable Curtailment	Summary Average
Weight	**60%**	**10%**	**10%**	**10%**	**10%**	**100%**
P3: NG-S	1,540 0.0	336.7 0.0	64% 1.43	2.50	6.10	1.00
P5: NG-S-GHG	1,553 0.52	342.9 0.40	68% 0.0	3.61	5.32	1.25
P6: NG-S-GHG-OTEC	1,612 2.90	341.2 0.29	67% 0.36	0.00	0.52	1.86
P2: NG-NS	1,564 0.97	337.5 0.05	57% 3.93	6.94	4.03	2.08
P4: D-S-GHG	1,729 7.62	457.2 7.83	65% 1.07	8.33	3.29	6.62
P1: D-NS	1,788 10.0	490.6 10.0	40% 10.0	8.33	6.01	9.43

Source: Pace Global

The key findings within each objective are summarized as follows. As mentioned previously, reliability was considered a constraint and not an objective. As such, it was ensured that all portfolios had enough firm capacity to meet the 1 day in 10 year LOLE reliability standard.

- Cost: Portfolio 3 with natural gas, renewables, and storage has the lowest net present cost followed by Portfolio 5 while Portfolio 1 with diesel and thermal resources and no storage has the highest cost. Overall Portfolios 3 and 5 do well on cost dimension followed by portfolio 2. Portfolios 1 and 4 with diesel perform the worst. The cost is inclusive of additional thermal capacity needed to bring Portfolios 4 and 5 into compliance.

- Risk: Portfolios 3 through 6 with natural gas perform well on rate stability given less variability in natural gas pricing over time.
- Environmental Stewardship: Portfolios 4 through 6 are designed to meet the carbon emission reduction goals but Portfolio 3 comes close to meeting the carbon emission reduction goals even on an economic basis. Portfolios 1 and 2 do not comply without storage.
- Curtailment: Portfolio 4 has the lowest levels of curtailment on average, followed by Portfolio 5. Portfolio 1 with diesel and no storage has the highest levels of curtailment.
- Diversity: Portfolio 6 scores the best from a diversity standpoint while Portfolios 1 and 2 that build only thermal and renewables score the worst.
- Land Use: Portfolio 6 with OTEC performs best from a land-use perspective while Portfolio 4 that builds large amounts of renewables to meet the carbon goals scores the worst.

Best Performing Portfolios

- Portfolio 3 performs the best in terms of rate stability and is also the best portfolio in terms of costs. However, this portfolio fails to sustain compliance with carbon reduction goals.
- Portfolio 5 is therefore ranked the highest and provides a good balance across all objectives, even though it is not the lowest cost portfolio. Portfolio 5 is the second lowest cost portfolio and achieves the best compliance with environmental goals.
- Portfolio 6 is ranked the highest in terms of diversity, land use, and renewable curtailment and adequately meets environmental compliance. However, OTEC is not commercially proven and is a hurdle for this portfolio.

Portfolios 5 and 6 are ranked as the highest compliant portfolios and are the recommended portfolios. Both portfolios meet carbon emission reduction goals, have manageable renewable curtailment and meet the reliability criteria at one of the lowest cost points. The portfolios also perform well in addressing rate uncertainty to customers. Further, given that both portfolios have the option to utilize natural gas, it provides the optionality to CUC to hedge against commodity price risks in the future. Portfolio 6 has the added advantage of having a baseload renewable resource that reduces the need for intermittent renewables and storage (with lower land use requirements) but the benefit comes at the higher cost point.

Worst Performing Portfolios

- Portfolio 4 is one of the worst performing portfolios. While the portfolio meets the environmental goals, it does so at a big cost given the continued reliance on diesel fuel. This portfolio also shows significant reliability violations given the need to rely on less thermal and more storage to meet the environmental goals. However, Portfolio 4 performs the best in terms of renewable curtailment given the large amounts of storage.
- Portfolio 1 is not a feasible option. It relies on large amounts of thermal capacity to integrate renewables and results in large curtailments and non-compliance with carbon emission reduction goals. It is also the highest cost portfolios and one with highest risk.
- Portfolio 2 does better than Portfolio 1 in terms of costs and risks but continues to rely on large thermal capacity. It comes closer to meeting the carbon emission reduction goals but without storage is unable to meet the goals. This portfolio is close to meeting the GHG reduction target with a 57% reduction in CO2. As technology improves this portfolio may have merit.

PIVOT OR FALL BACK STRATEGIES AND OPTIONS

There are potentially a number of uncertainties associated with the suggested portfolio plan. These uncertainties relate to the difficulty permitting renewable resources (particularly wind but also large amounts of solar), difficulty bringing on the Ocean Thermal Energy Conversion facility, challenges with battery energy storage maturation and safety concerns, and issues related to bringing natural gas infrastructure to the island.

Exhibit 51: Signpost Strategies

Signpost	Strategy
OTEC Does not Materialize	Pursue Portfolio 5
Not all Renewables, particularly wind, get Permitted	Pursue Portfolio 6 with more solar and baseload renewables
OTEC Does not Materialize and both wind and solar have difficulty with permits	Revisit IRP
Batteries not able to achieve maturation and scale in a safe and reliable manner	Pursue Portfolio 6 with more recips and baseload renewables
OTEC Does not Materialize	Pursue Portfolio 5

To address the uncertainties, pivot strategies have to be considered such that the utility has an ability to rapidly switch to another portfolio strategy if market or economic conditions change. Exhibit 51 shows the key signpost and the possible pivot strategy to deal with the uncertainty. As an example, if OTEC does not materialize, the utility would fall back on Portfolio 5 which is the other suggested portfolio. If batteries don't hold their promise or if intermittent renewables have difficulty with permitting, baseload renewable options such as OTEC would have to be pursued. If natural gas infrastructure to bring natural gas to the island and the power plant does not materialize, Portfolio 4 with larger amounts of renewables and storage would have to be developed. Finally, in the eventuality that both OTEC and intermittent renewables cannot happen, then the utility may have to revisit the IRP and pursue other baseload generation technology options or revisit strategy with respect to demand side management and distributed solar. It's also possible that the National Energy policy directive on carbon emission reduction goals may have to be re-evaluated.

Further, the IRP analysis indicates that many of the recommended actions over the next several years are independent of the portfolio choice. No matter what the portfolio path is pursued, certain actions have to be under-taken. For example, in all cases, the renewable procurement strategy would have to be devised, battery energy storage specifications would have to be developed, and new procurement of thermal generation assets will need to focus on more flexible reciprocating engines. Furthermore, analytical studies centered on battery integration and grid impact analysis would have to be conducted.

APPENDIX I: LOSS OF LOAD EQUIVALENT ANALYSIS

As part of the assessment designed to screen candidate options for the ultimate portfolio review, Pace Global conducted an analysis of the reliability of each portfolio option. This analysis is referred to as a loss of load ("LOL") assessment and essentially tests the likelihood that CUC's generation system will be unable to meet load for any period of time. The analysis entails Monte Carlo-based simulations for outages in the generation and transmission system, as well as uncertainty in hourly loads for CUC's system. Monte Carlo methods involve random sampling across a distribution of possible outcomes, and this analysis has deployed such methods to evaluate future possible conditions for CUC's load and availability of supply resources in any given hour. The industry standard for loss of load events ("LOLE") is one day in ten years ("1-in-10 Standard").[26] Most jurisdictions define this as 24 hours in a ten year period. Pace Global has used this standard in benchmarking its analysis.

METHODOLOGY OVERVIEW

Aurora has the functionality to randomly "remove" power plants or other elements of CUC's system, such as transmission lines, from the available supply of resources for limited periods of time to simulate forced outage events. Pace Global coupled this random outage functionality with a set of load projections that was stochastically varied, providing both higher and lower load outlooks over five hundred different paths. Combining these two key elements of system uncertainty, Pace Global evaluated the frequency with which the various portfolio options would be unable to meet CUC load.

Definition of Loss-of-Load Event

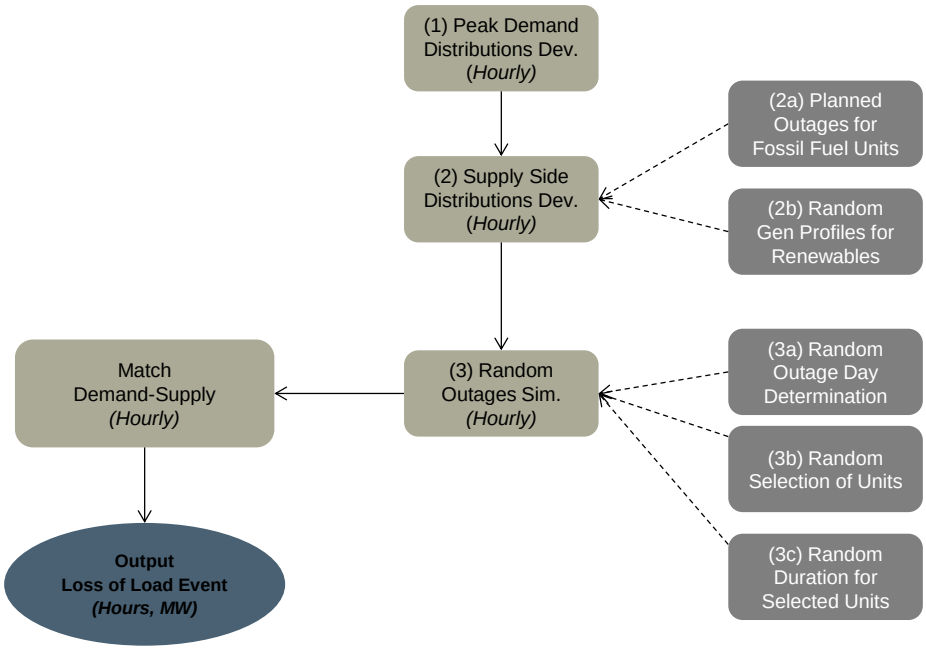
For the purposes of the IRP study, the following definitions are used:

- A LOL Event is defined as any hour or consecutive set of hours when the total available capacity in the CUC system (inclusive of import capability) is insufficient to meet CUC's load in that hour or set of hours;
- LOL Hours are defined as the total number of hours over the simulation period during which the total available capacity in the CUC system is insufficient to meet CUC's load.
- Target Objective: For this study, the LOL threshold was set as < 2.4 hours per year.

For the analysis, Pace Global tracked the number of loss of load events, along with total loss of load hours and total loss of load MWh, for each portfolio. Exhibit summarizes the key inputs and outputs for the assessment.

[26] The following sources provide an overview of the standard and its definition and applicability in the industry:
The Brattle Group and Astrape Consulting, "Resource Adequacy Requirements: Reliability and Economic Implications" prepared for FERC, September 2013. http://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf
Hogan, William W., "Connecting Reliability Standards and Electricity Markets" presentation for Harvard Electricity Policy Group, December 8, 2005. http://www.hks.harvard.edu/fs/whogan/Hogan_hepg_120805.pdf
PJM Generation Adequacy Analysis: Technical Methods, October 2003.

Exhibit 52: LOLE Methodology Overview



Source: Pace Global

Test Years

The LOL study is a data intensive exercise, with the simulations involving 500 probability distributions of load, unit outages and other variations in the intermittent generation profiles for renewables. In addition to these, unit specific historical outage events were calibrated to unique probability distributions (such as a log-normal, exponential, generalized extreme value distribution etc.). These probability distributions represent specific down times for the units (also called "Mean-Time to Repair or MTTR). So, Pace Global conducted the analysis for three representative test years over the IRP study period.

Three test years were chosen for the LOLE study, 2020, 2029, and 2040, considered to be representative of critical points in time during the IRP study period. For periods prior to 2020, the CUC system is nearly all diesel with significant reserve margins. By 2020, solar capacity starts to come on the system. By 2029, significant amount of solar makes entry in nearly all portfolios before the optimal storage buildout has not taken place.

Intermittent generation resources can impair the reliability of the system. By 2040, more significant changes will have occurred in CUC's system, including the retirement of nearly all existing capacity, and additional evolution in energy efficiency and distributed generation. The 2040 year is also closer to the end of the IRP study period. In consultation with CUC, Pace Global determined that these three years would be sufficient to capture the likely reliability impacts of different portfolios, and thus allow a clear ranking of the portfolios under consideration.

SYSTEM SUPPLY ELEMENTS AND ASSOCIATED UNCERTAINTY

The analysis considered two forms of outages – planned outages and forced outages. Planned outages were based on CUC's outage schedule with most of the outages scheduled in the winter and Spring months. The forced outage was a random variable with the randomness based on historical data on number of outage events and duration of outages. As event specific data was not available, Pace Global used an exponential distribution to determine the width of the distribution. In an exponential distribution, only the mean duration of outages is needed.

In addition to considering planned and forced outages for thermal units, randomness for solar and wind resources was also considered. As multi-year historical operational data was not available, met-tower and solar manufacturer data was used with the diurnal hourly variability for each month based on the variability in the output for the hour, each day of the month. Finally, some of the portfolios had storage. The storage availability was based on the storage output shape. Similar assumptions were used for OTEC, MSW, and landfill gas facilities.

Pace Global introduced random variation into the occurrence of plant forced outages using explicit probability distributions which were fitted to actual events. The random frequency and duration method takes into consideration the Forced Outage Rate ("FOR") of each unit as well as the mean time to repair ("MTTR") required to bring the unit back online. The FOR and MTTR values were developed for all fossil fired units in consultation with CUC and are summarized in Exhibit 53.

Exhibit 53: Summary of FOR and MTTR for CUC System Elements

S. No	Units	Unit Avg. Down Hours (MMTR)
1	Unit 1	11
2	Unit 2	5
3	Unit 3	12
4	Unit 4	12
5	Unit 19	16
6	Unit 20	75
7	Unit 25	50
8	Unit 26	30
9	Unit 28	15
10	Unit 30	4
11	Unit 31	3
12	Unit 32	6
13	Unit 33	3
14	Unit 34	24
15	Unit 35	12
16	Unit 36	10
17	Unit 41	60
18	Unit 42	55
19	Unit 42	45
20	Unit 44	25

Sources: Pace Global and CUC.

The analysis was performed for four portfolios identified below:

- P1: 170 MW of new Diesel fired thermal generation plus 154 MW of utility scale wind and solar resources. No storage resources were considered in this run.
- P4: 98 MW of new Diesel fired thermal generation, 223 MW of utility scale wind and solar resources. Finally, 125 MW of battery energy storage resources.
- P5: 112 MW of new Diesel fired thermal generation plus 179 MW of utility scale wind and solar resources. Finally, 60 MW of battery energy storage resources.
- P6: 146 MW of new Diesel fired thermal generation plus 134 MW of utility scale wind and solar resources, and 12.50 MW of OTEC resources. Finally, 20 MW of battery energy storage resources.

SYSTEM LOAD UNCERTAINTY

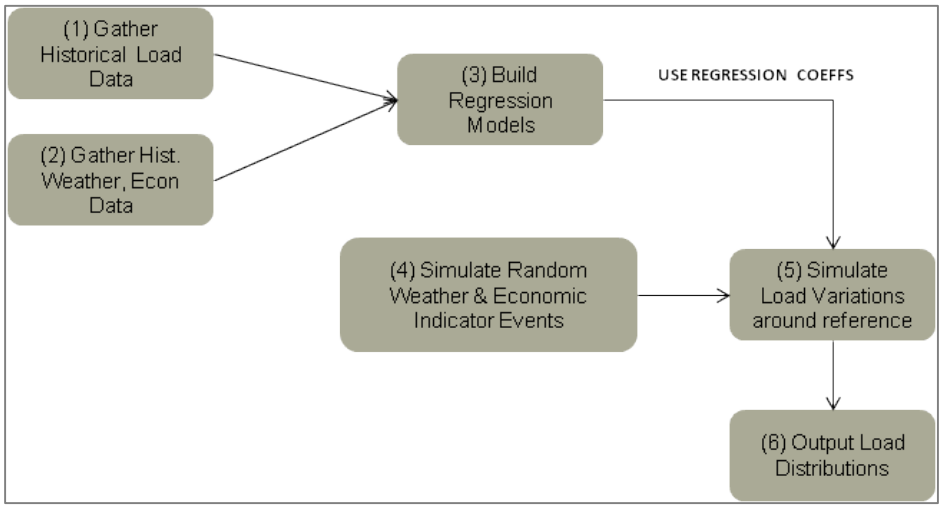
Pace Global developed a distribution of potential load growth paths in order to perform the stochastic LOLE assessment. The starting point for developing the stochastic load distributions is the base case Gross load forecast (the forecast before adjusting for energy efficiency and demand response expectations). For this study, the gross system load is stressed for extreme weather events and economic variables only. Pace global used the last 10-year historical weather data to stress the system load.

Pace Global produced a distribution of monthly average and peak loads using the methodology described below. The process to produce this distribution can be summarized by the flow chart in Exhibit 54. Statistical relationships between energy and peak load versus weather and economic indicator events were developed using the historical data. The regression coefficients for the relationships were obtained for monthly energy and peak load separately.

To forecast future weather uncertainties, Pace Global considered the past 10-years of historical weather and performed a random sampling of weather events throughout the study period. The economic indicator variable was stressed using a Geometric Brownian Motion model, in which the historical drift and diffusion terms were estimated using the actual data sets.

The final step was to simulate the load deviations using the coefficients and the forecasted weather and economic uncertainties. The deviations were then applied to the base case reference load forecasts to come up with a distribution of monthly energy and peak load forecasts.

Exhibit 54: Risk-Integrated Power Demand Modeling Overview



Source: Pace Global

Historical Driver Analysis

Similar to the baseline load forecast analysis, weather and economic data have historically explained CUC's monthly average and peak load fairly well. This relationship forms the basis for Pace Global's load uncertainty analysis. The historical weather data includes Heating Degree Days ("HDD"), Cooling Degree Days ("CDD") and Humidity. The basic premise of our stochastic model is that load can be expressed as follows:

$$Load_t = \alpha + (\beta_1 * HDD_t) + (\beta_2 * CDD_t) + (\beta_3 * HUM_t) + (\beta_4 * PI_t) + \xi_t$$

Where:

- HDD (Heating Degree Days): 65 - Average daily temperature in degrees Fahrenheit or zero. HDD is never negative.
- CDD (Cooling Degree Days): Average daily temperature - 65 in degrees Fahrenheit or zero. CDD is never negative.
- HUM (Humidity): Average daily percent humidity.
- PI: Personal Income
- ξ : A normally distributed error term with mean 0 and constant variance
- α : A constant derived from the regression analysis
- β_n: Estimated coefficients derived from the regression analysis

Load Stochastics Propagation

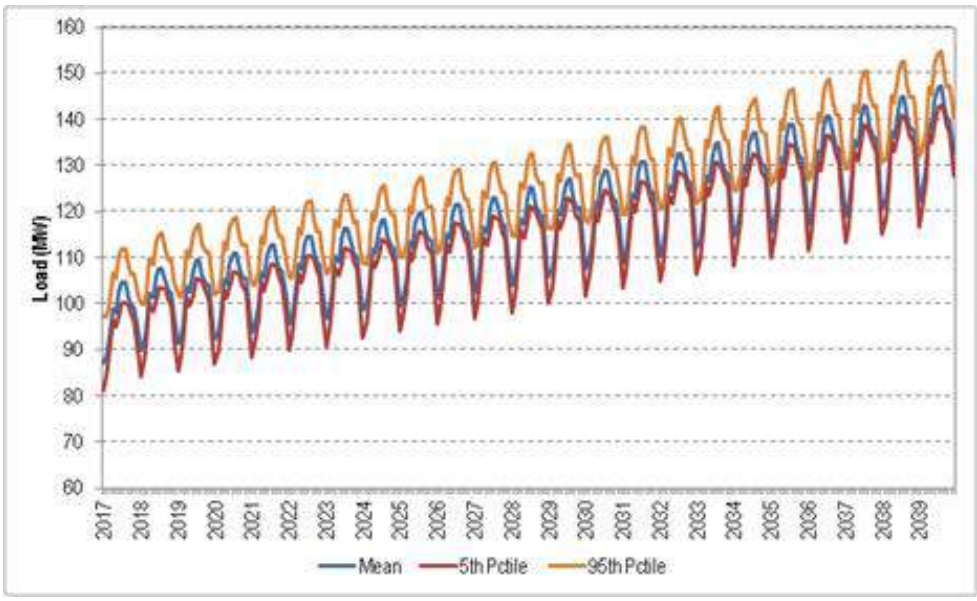
To produce the load stochastics, Pace Global propagated three independent random paths: weather data, personal income, and a residual.

Weather data includes heating and cooling degree days and humidity. To produce reasonable weather data projections, Pace Global samples actual yearly paths from history. For this analysis, 10 years of historical data were used to perform the historical driver analysis. For every Monte Carlo iteration, the

sampling of historical weather data is performed with “Equal-Weighted” probability for all historical years. This sampled historical weather for a year is considered as the forecast of weather for a specific year in the forecast time period. To account for unexplained variation in the observed data (i.e. error term), a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression was added to the equation.

Exhibit 55 shows the monthly peak load stochastic distributions used for LOL study, over time for the CUC system. Note that each line is not a discrete path or load forecast, but a representation of the probability of being at or below that point across the entire distribution of potential outcomes.

Exhibit 55: Peak Load Stochastic Distribution



Source: Pace Global

Hourly Load Forecasts

The LOL study was done on an hourly basis. The monthly average and peak load forecasts thus obtained as discussed above were then converted to hourly load profiles (8760s). In order to do this, the “Unitized Load Estimation Technique” was implemented. This technique would make sure that both the estimated average and peak load values would be preserved while converting the monthly values into hourly profiles. There are two steps in this technique.

1) Determine the unitized load factor:
   The unitized load factor is determined for every hour in the month. It is computed using the equation:

$$ULF_h = \frac{(Load_h - AvgLoad)}{(PeakLoad - AvgLoad)}$$

2) Estimate the hourly load for the corresponding average and peak:

Using the load factor calculated above, the monthly average and peak loads are adjusted using the equation below, to arrive at the final hourly load profiles.

$$CalcLoad_h = \{ \left(ULF_h * (PeakLoad - AvgLoad)\right) + AvgLoad\}$$

USE OF 500 ITERATIONS

Monte Carlo methods are performed by running simulations repetitively, by sampling the input parameters every time the model is run. The accuracy of the results being estimated is proportional to the number of times the model is run. This relationship is thought to be exponentially increasing, so that at some point the repeated sampling of input parameters will yield a stable expected value of Loss of Load. In this context, we define convergence as "the optimal number of times the model needs to be run, in order to produce stability in the output parameter value being estimated, by fixing all input parameters."

Under Monte Carlo Analysis, the CUC simulation model is run for a series of iterations, each one providing a different number of LOL Events during the course of the 8760 hours that make up each year. Using the theory of statistical convergence, the optimal number of runs required for the LOL study was estimated. Pace Global performed test runs to determine the optimal number of runs (iterations) required for this study. The output parameters stabilized around 500 iterations, every time the model was run. Therefore, for the purposes of the study, we set to 500 as the number of iterations to meet the convergence criteria for the Monte Carlo simulation.

LOLE FINDINGS

The table shown in Exhibit 56 below shows the results of the LOL study for the four portfolios, for the three representative years. The table indicates two columns for each year:

- The first column represents the number of hours in a year across 500 simulations, when the supply is unable to meet the load. The hours are representative of the maximum number of hours across the 500 iterations when there is a shortfall.
- The second column represents the max capacity shortfall, in a year across 500 simulations

As shown, Portfolio 4 with diesel and large amounts of renewables and storage has the highest number of LOLE hours. For this portfolio, violations are observed in both 2029 and 2040 with a maximum capacity shortfall of 56 MW. Portfolio 5 also has LOLE violations but only in 2040 with fewer hours of shortfall but the magnitude of the shortfall is slightly higher at 61 MW. Other portfolios tested also had a few violations but were below the 2.4 hours threshold identified in the study.

Exhibit 56: Summary of Initial Loss of Load Study Findings

Portfolio	Year 2020		Year 2029		Year 2040	
	Hours with Loss of Load	MW Short	Hours with Loss of Load	MW Short	Hours with Loss of Load	MW Short
Portfolio 1	0	0	1	(5)	2	(9)
Portfolio 4	0	0	185	(55)	166	(56)
Portfolio 5	0	0	0	0	42	(61)
Portfolio 6	0	0	1	(3)	1	0

Source: Pace Global analysis

Exhibit 57: Summary of Final Loss of Load Study Findings

Portfolio	Year 2020		Year 2029		Year 2040	
	Hours with Loss of Load	MW Short	Hours with Loss of Load	MW Short	Hours with Loss of Load	MW Short
Portfolio 1	0	0	1	(5)	2	(9)
Portfolio 4	0	0	0	0	1	(3)
Portfolio 5	0	0	0	0	0	0
Portfolio 6	0	0	1	(3)	1	(0)

Source: Pace Global analysis

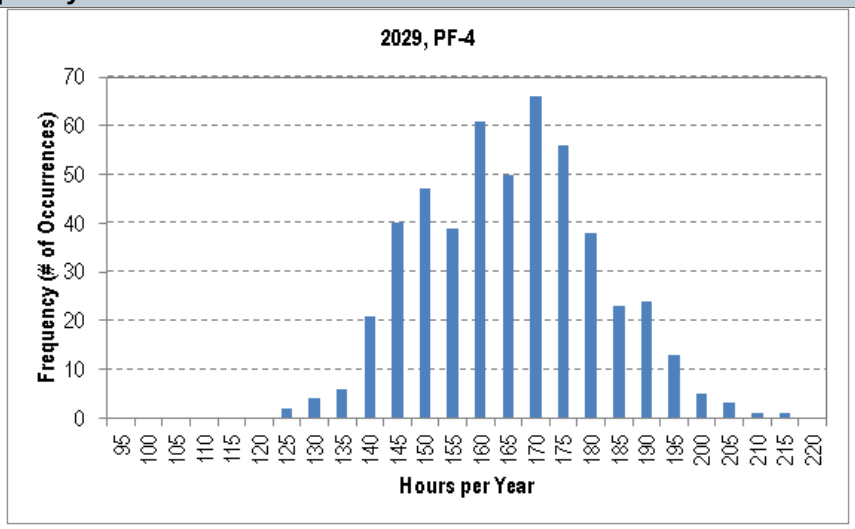
The portfolios with significant violations (Portfolio 4 and 5) were re-run with the additional MW capacity included in the portfolio. Large Reciprocating engines (18 MW size) were added to the portfolio for test years where a capacity shortfall was found. As shown in Exhibit 57, this helped restore the reliability to within the minimum threshold.

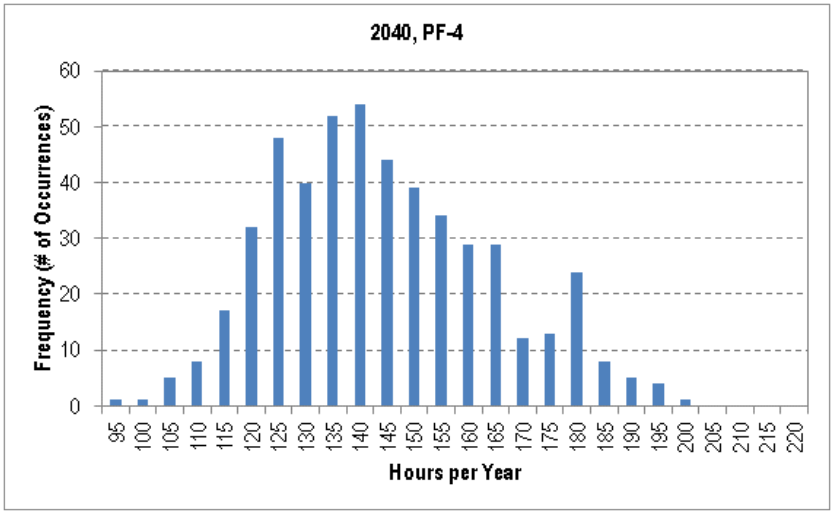
LOLE Frequency Analysis

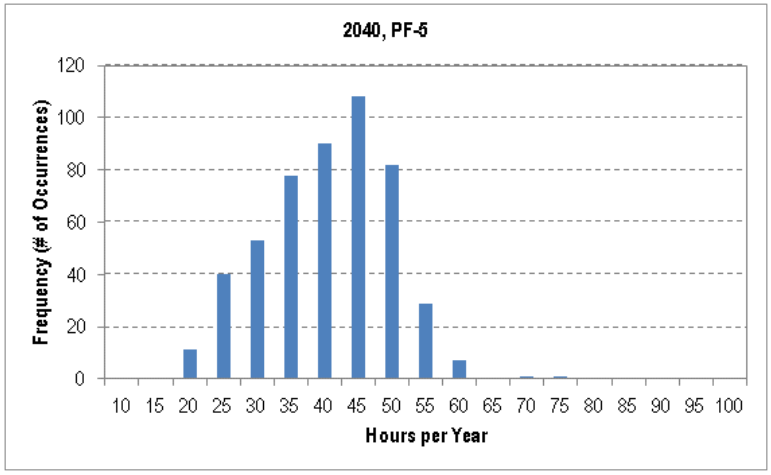
To better understand the LOLE under the Monte Carlo analysis performed, Pace Global performed a frequency analysis on the number of loss of load events (hours) for every iteration. This analysis results in a frequency distribution plot or a histogram, which is simply the number of loss of load events or hours, summarized for all 500 iterations, looking at each portfolio separately.

As shown in Exhibit 58, portfolio 4 for years 2029 and 2040 has the most occurrences of LOL events. Portfolio 5 for year 2040 has relatively less number of LOL events. This is due to the presence of more renewables mix in the portfolio, where in the intermittency in their generation profiles lead to LOL events. Presence of more fossil fuel units in the portfolio scores high in reliability metric, with no occurrences of LOL events for such portfolios.

Exhibit 58: Frequency distributions of LOL Events across Iterations for Select Portfolios, Years







Source: Pace Global analysis

LOLE ANALYSIS CONCLUSIONS

The LOLE analysis concludes the following with regard to meeting CUC's reliability constraint:

- Portfolio 4 with fewer thermal capacity and significant intermittent generation and storage capacity has higher levels of reliability issues.
- Portfolio 5 with slightly less renewable and storage capacity also shows some violations but only in 2040. There is some reliability risk here.
- Reliability can be restored by adding additional thermal generation capacity. The study identified the need for an additional 55 to 60 MW of firm capacity to bring back the reliability violations to within the desired thresholds.

APPENDIX II: SOLAR PENETRATION ANALYSIS

As part of the CUC IRP assessment, Pace Global conducted a distributed solar penetration analysis. The solar penetration levels impact the cost to serve CUC's remaining load as well as the magnitude of the required renewable build-out to meet carbon emission goals, as customer-sited solar reduces retail sales, and total energy consumption, and can increase costs if the solar generation is heavily subsidised by other customers.

METHODOLOGY OVERVIEW

Pace Global has developed solar penetration estimates based on established methodologies that have been used in the past and adopted by the National Renewable Energy Laboratory ("NREL"). This includes an estimation of the maximum market share and adoption rate as a function of the payback period. The payback period in turn is a function of module capital costs, assumptions for compensation for sell back, and financing assumptions.

The input assumptions were based on CUC-specific customer demand levels, Cayman-specific capital cost estimates, and Glendale Water and Power retail rate projections. The analysis is conducted separately for residential and commercial customers, with the solar PV module size being the key difference between the two customer classes. For sake of simplicity, the analysis is broken down into three discrete ten year periods[27] – early, mid, and late – with payback periods calculated for each period based on long term cash flows. The analysis uses these discrete periods because of expectations that the cost of solar PV will fall over time. Discrete periods are used in the IRP as a simplification from a continuous function that would reflect the cost reductions. The MWh reductions in demand due to solar penetration can be viewed in terms of energy reduction (MWh) and solar PV meter count over time. However, solar PV is modeled as a generation resource in the production cost model.

INPUT ASSUMPTIONS

There are a number of input assumptions to the solar penetration analysis. The items listed below are the key assumptions underlying the analysis:

1) Module Size: An 8 kW module was chosen for the residential customer, while a 50 kW module was chosen for the commercial customer. The module size was based on observed average module sizes across residential and commercial classes. The solar module capacity factor was assumed to be in the 15-17% range, consistent with historically achieved capacity factors for operational modules.

2) Technology Capital Costs: Solar PV costs for residential and commercial customer-sited installations are currently in the $3,050/kW and $2450/kW range, respectively. The costs are projected to decline to $2,350/kW for residential and $1,900/kW for commercial by the end of the decade, with decline rates slowing thereafter, such that projected costs are $2,200/kW for residential and $1750/kW for commercial by 2030. The costs per kW were lower for commercial customers relative to residential customers due to scale economies inherent in larger project sizes. Exhibit 59 shows the rooftop solar capital cost trajectory over time.

3) Rate Structure for Savings and Surplus: The assumed savings rate for any energy not consumed due to solar generation is based on avoided cost of energy (largely fuel). The assumed compensation rate for any surplus power sold back to the utility is based on lower of avoided cost and solar levelized cost of energy. The avoided cost is assumed to be largely a function of the fuel

[27] Early period is 2016-2025, mid period is 2026-2035, and late period is 2036-2045.

prices. To avoid the circularity associated with the avoided cost being a function of the model run and the model run needing a distributed solar penetration to come up with avoided costs, Pace Global assumed avoided cost values for the solar penetration analysis. The avoided costs were based on diesel fuel prices in the 2017-2019 periods, on natural gas in the 2020-2024 periods and a hybrid of natural gas and renewables post 2024[28]. It was assumed that as renewables grow over time, avoided fuel costs would decrease over time, thus reducing the compensation. Additionally, from 2017-2019 the full core rate was modelled which is .346 $/KWh for residential and .259 $/KWh for commercial. Exhibit 69 shows an average avoided cost rate trajectory and the distributed solar capital costs in real dollars.

Exhibit 59: Retail Rate and Capital Cost Projections

Year	Avoided Cost Rate ($/KWh)	Residential Capital Cost ($/KW)	Commercial Capital Cost ($/KW)
2017	0.301 [1}	2,993	2,394
2018	0.301	2,913	2,330
2019	0.301	2,809	2,247
2020	0.146	2,770	2,216
2021	0.148	2,639	2,111
2022	0.149	2,569	2,055
2023	0.149	2,506	2,005
2024	0.15	2,449	1,959
2025	0.113	2,397	1,918
2026	0.114	2,350	1,880
2027	0.114	2,306	1,845
2028	0.114	2,265	1,812
2029	0.114	2,228	1,782
2030	0.076	2,193	1,754
2031	0.076	2,160	1,728
2032	0.076	2,129	1,703
2033	0.076	2,100	1,680
2034	0.076	2,072	1,658
2035	0.076	2,021	1,617
2036	0.076	2,021	1,617
2037	0.076	1,998	1,598
2038	0.077	1,976	1,580
2039	0.077	1,954	1,563
2040	0.077	1,934	1,547
2041	0.077	1,914	1,531
2042	0.078	1,895	1,516

[28] Between 2025 and 2029, it was assumed that renewables would be on the margin 25% of the time and 2030 onwards, renewables would on the margin 50% of the time.

2043	0.078	1,877	1,502
2044	0.078	1,860	1,488
2045	0.078	1,843	1,475

[1} Simple average of residential and commercial rates shown just for illustration.
Source: Pace Global analysis and GWP rate information

4) Financing Assumptions: The solar module acquisition was assumed to be based on an ownership model with 20% down-payment, with the remaining investment being debt financed. A debt rate of 5.5% was used for the financing. This was largely based on 200 basis point spread over the prevailing prime rate which was 3.5%[29].

5) Subsidies and Tax Credits: The CORE program currently compensates solar customers at a rate of 28 cents/kWh for 98 kW systems and 20 cents/kWh for 50 kW systems. However, the CORE program currently has a cap of 6 MW[30]. It is assumed that the CORE program in its current form will continue until a penetration level of 10 MW and then switch to an avoided cost structure past that. No sovereign tax credits are available for distributed solar installations.

SOLAR PENETRATION CURVES

Pace Global conducted an analysis for Glendale with the objective of quantifying the total load reduction from solar PV installations in California. In developing the solar penetration levels, Pace relied on NREL documentation[31] in addition to its own experience and observations with developing penetration curves. There are three key components to this calculation: maximum market share, penetration or adoption rate, and energy available from PV installations[32]. The combination of these three variables results in the reduction in load from solar panel penetrations. Below is a more detailed outline of the assumptions that were used to estimate each variable.

The maximum market share is a function of the payback period, which represents the duration for the solar PV installation to break even (i.e., NPV of the cash flow = 0). The maximum market share is an exponentially declining function in relation to the payback period defined as follows:

$$Maximum\ Market\ Fraction = e^{-Payback\ Sensitivity\ *\ Payback\ Time}$$

Pace Global assumed the payback sensitivity to be 0.3, an industry standard that was approximated by experts who have conducted research in this area.[33]

The penetration rate represents the cumulative adoption of a new technology since its introduction to the market. The curve is characterized by an "S" shape (S-curve), which shows a slower rate of growth in the initial and the late stages of the technology, but a faster adoption rate in the mid-stage.

The "energy available from PV installations" is estimated by multiplying the kW module size assumed above by the expected capacity factor.

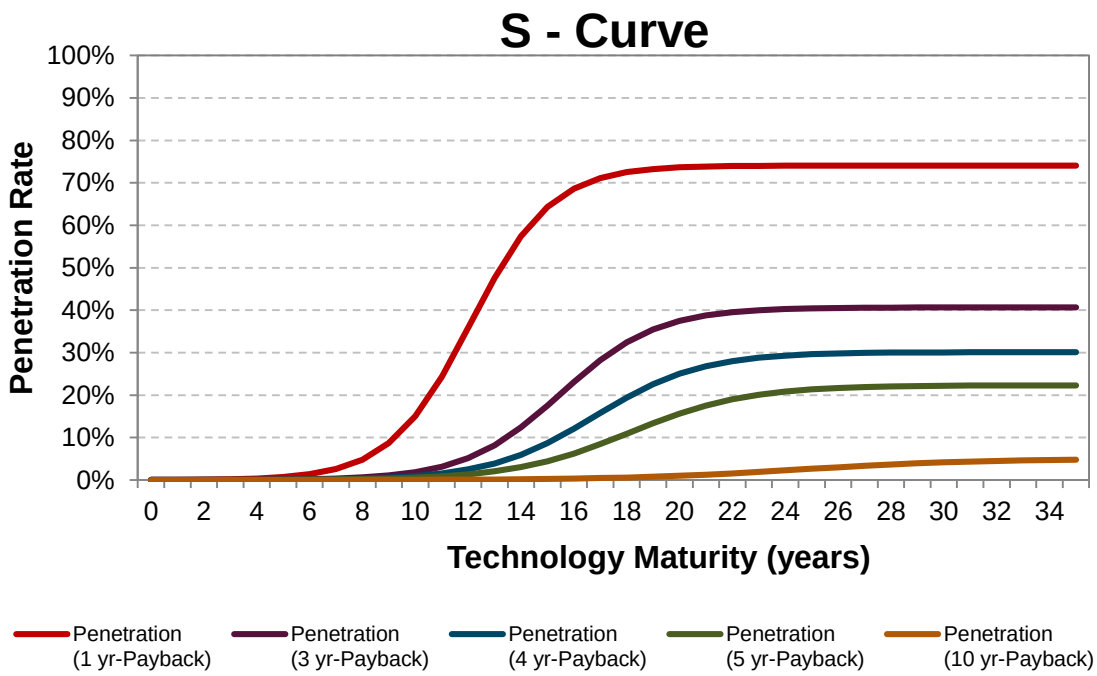
The initial observation from the simulated S-curves is that the adoption rate increases as the payback period

[29] Based on press release on Cayman solar loans
[30] The cap was recently increased to 8 MW.
[31] See NREL "The Solar Deployment System (SolarDS) Model: Documentation and Sample Results".
[32] Energy available from PV installations is a function of module size and capacity factor.
[33] See page 19 of the NREL report.

decreases. Because the payback period may shift due to changes in capital costs or retail rates over time, Pace Global constructed a composite S-curve that represents the transition from one curve to another over time as payback period changes. This transition logic produces a more realistic rate of adoption and has implications for the maximum market share as time progresses. As noted above, the forecast horizon was split into three ten-year periods (early, mid, and late), with an average capital cost and compensation rate representation for each period. Payback periods were developed for each period and the composite S-curve created over the forecast horizon by transitioning from one S-curve to another.

Exhibit 60 shows the S-curve employed in the analysis for various S-curves with a composite S-curve for the commercial and residential class. Both the commercial and residential classes hit the 10 MW cap by the 2018-2019 period given the high CORE rates. Over time, avoided costs decrease due to penetration of renewables but the capital costs also decrease. For commercial class, the capital costs are lower due to the scale effect. Therefore, in the mid to late period, the payback is closer to 7 years. For the residential sector, the payback is significantly higher.

Exhibit 60: S-Curve Representation



Source: Pace Global analysis and NREL

SOLAR PENETRATION PROJECTIONS

Exhibit 61 shows the solar penetration projections over time for residential and commercial customers. As shown, by 2045 the solar energy production is estimated to be 13% of energy consumption for commercial customers and approximately 7.4% for residential customers. As explained above, the reduction to load or the energy available from PV installations is a function of module size, capacity factor, and penetration rate. Total PV installations by the early 2030s are expected to be between 60 MW and 70 MW. This level of installed distributed generation will require local generation or energy storage for integration into the GWP system. In terms of meter count, this translates to 518 commercial meters and 2,498 residential meters

by the early 2030s.

Exhibit 61: Solar PV Penetration Projections

Commercial	Reduction in Load (MWh)	Total Load (MWh)	Load Reduction (%)	Installed PV (kW)	PV Meter Count
2016	3,407	299,244	1.1%	2,593	52
2017	3,863	299,244	1.3%	2,940	59
2018	4,652	304,571	1.5%	3,540	71
2019	6,008	308,032	2.0%	4,572	91
2020	8,309	311,076	2.7%	6,323	126
2021	10,075	314,133	3.2%	7,668	153
2022	12,069	317,252	3.8%	9,185	184
2023	14,408	320,434	4.5%	10,965	219
2024	17,060	323,679	5.3%	12,983	260
2025	19,949	326,991	6.1%	15,182	304
2026	22,969	330,368	7.0%	17,480	350
2027	25,998	333,814	7.8%	19,785	396
2028	28,914	337,330	8.6%	22,004	440
2029	31,621	340,916	9.3%	24,065	481
2030	34,057	344,574	9.9%	25,918	518
2031	36,194	348,306	10.4%	27,545	551
2032	38,037	352,114	10.8%	28,948	579
2033	39,610	355,998	11.1%	30,144	603
2034	40,947	359,960	11.4%	31,162	623
2035	42,086	364,002	11.6%	32,029	641
2036	43,067	368,126	11.7%	32,775	656
2037	44,071	372,332	11.8%	33,540	671
2038	45,101	376,624	12.0%	34,323	686
2039	46,156	381,002	12.1%	35,126	703
2040	47,237	385,468	12.3%	35,949	719
2041	48,346	390,024	12.4%	36,793	736
2042	49,482	394,672	12.5%	37,658	753
2043	50,647	399,414	12.7%	38,544	771
2044	51,840	404,251	12.8%	39,452	789
2045	53,064	408,698	13.0%	40,383	808

Residential	Reduction in Load (MWh)	Total Load (MWh)	Load Reduction (%)	Installed PV (kW)	PV Meter Count
2016	3,661	277,782	1.3%	2,786	348

2017	4,091	277,782	1.5%	3,113	389
2018	4,844	292,120	1.7%	3,686	461
2019	6,151	300,030	2.1%	4,681	585
2020	8,392	306,988	2.7%	6,387	798
2021	10,159	313,975	3.2%	7,731	966
2022	12,182	321,102	3.8%	9,271	1,159
2023	14,587	328,374	4.4%	11,101	1,388
2024	17,350	335,792	5.2%	13,204	1,650
2025	20,407	343,359	5.9%	15,530	1,941
2026	23,657	351,079	6.7%	18,004	2,250
2027	24,278	358,954	6.8%	18,476	2,310
2028	24,918	366,988	6.8%	18,963	2,370
2029	25,577	375,184	6.8%	19,465	2,433
2030	26,256	383,545	6.8%	19,982	2,498
2031	26,955	392,075	6.9%	20,514	2,564
2032	27,676	400,776	6.9%	21,062	2,633
2033	28,418	409,653	6.9%	21,627	2,703
2034	29,183	418,708	7.0%	22,209	2,776
2035	29,971	427,946	7.0%	22,809	2,851
2036	30,782	437,371	7.0%	23,426	2,928
2037	31,618	446,985	7.1%	24,063	3,008
2038	32,480	456,793	7.1%	24,718	3,090
2039	33,367	466,798	7.1%	25,394	3,174
2040	34,282	477,005	7.2%	26,089	3,261
2041	35,223	487,418	7.2%	26,806	3,351
2042	36,194	498,040	7.3%	27,545	3,443
2043	37,193	508,877	7.3%	28,305	3,538
2044	38,223	519,932	7.4%	29,089	3,636
2045	39,284	530,851	7.4%	29,896	3,737

Source: Pace Global analysis

ASSESSMENT OF RATE DESIGN CHANGES

Objective

The objective this task is to offer recommendations that strategically address the needs for specific cost of service and rate design studies that would be used to quantify the impact on retail electric prices of alternative resource portfolios defined within the Integrated Resource Plan.

Rate Structure Review

The basis for this review included the following resources:

- *The 2014 Cost of Service Study* prepared by Utility Consulting Services for the Caribbean Utilities Company, Ltd. ("CUC"), dated May 2, 2014. This study was commissioned by CUC "for the

purpose of developing proposed revisions to the Base Rates to be implemented effective June 1, 2014 in connection with the annual rate level adjustment prescribed by the Rate Cap and Adjustment Mechanism (the "RCAM") in the T&D License."[34]

- *Proposed CUC Demand Rates Study* prepared by Utility Consulting Services for the Caribbean Utilities Company, Ltd. ("CUC"), dated December 6, 2016. This latter study prepared by Utility Consulting Services and commissioned by CUC addresses the potential mismatch between fixed and variable cost recovery that can occur as retail consumers self-invest in such distributed energy resources (DER) as rooftop solar systems.
- *"Revised rates for the Large Commercial ("Rate L") rate class that would replace the existing energy charge rate component with a combination of energy and demand charges, taking into consideration that certain Rate L customers may own on-site generation to serve a portion of their electricity requirements, or distributed energy resources" ("DER"); and*
- *Proposed Residential ("Rate R") and Commercial ("Rate C") demand-and-energy rates that would apply to only those respective customers with DER." (page 1)*

The proffered rate structures employ a two-part demand charge to reflect both short and longer term benefits and costs of DER operations on the CUC system. The report concludes *"(T)hat customer would continue to pay for the cost of facilities standing by in the event of an outage but would not pay for some generation costs to the extent that the DER reduces the need for generation from CUC*." (page 3)

For large industrial customers under Rate L, the company also seeks to introduce a demand charge regardless of whether this class of customer employs a DER system or not. The report recognizes that proposed rate designs "represents a significant shift from the historical practice for CUC and therefore, a potential disruptive change for this class of customers." (page 6) For Rate L customers who do not currently own DER systems, the demand charge will be phased-in over a three year period.

DER Evaluation

Over the last decade, several state regulatory commissions in the United States have authorized the public utilities that they regulate to offer net metering rates which provides retail customers who have installed solar electric systems an economic incentive to further offset their electric charges with the ability to sell back to the utility surplus electric production at a rate equal to the retail rate for their class of service. Typically, this is accomplished via "reversed metering", i.e., the reverse flow of electricity into the electric distribution network. While this regulatory policy has had the direct effect of stimulating the market penetration of renewable distributed energy resources, particularly residential roof top solar electric systems, as the number of installations grew, it became evident that this policy also affected the electric utility's cost of service by:

- Overpaying DER participants for buy-back rates by not considering:
  - The fixed costs associated with embedded distribution and transmission investments
  - Associated incremental T&D system protection investments required to upgrade the network for bi-directional flow
  - Changes in the utility's generation supply portfolio
  - Potential supply imbalance charges
- Causing both intra and inter class cross subsidization of DER excess costs to non-participating customers.
- Artificially incentivizing DER investments when system costs exceed benefits.
-

Recognizing that the solar DER technology is maturing, that solar DER unit costs have rapidly declined, and that the magnitude of cross-subsidization is growing to measurable levels, utilities and regulators have

[34] 2014 Cost of Service Cover Letter prepared by Mr. Doug Handley of Utility Consulting Services.

begun to adopt and consider alternative solutions that can reward DER customers for the savings they produce without imposing an unfair cost to non-participants. Several examples include:

- The installation of a separate DER meter with accompanying cost based buyback rates
- The introduction of demand charges that more closely reflect the cost impact of solar DER on a utility's fixed, demand responsive charges.
- The use of real time meters to more accurately credit DER participants for avoided utility costs.
-

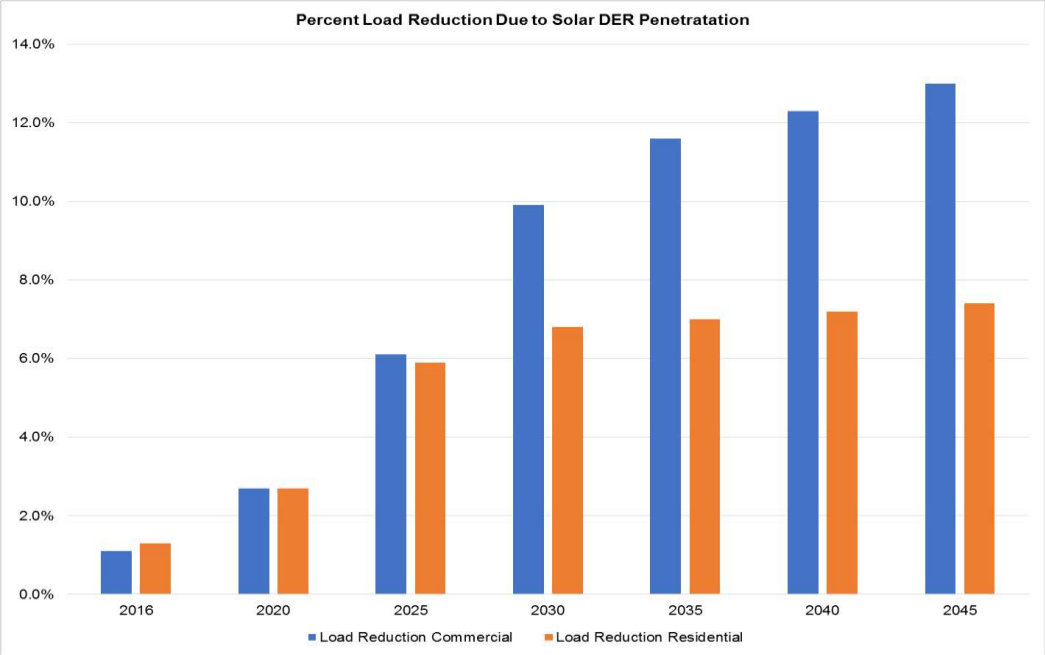
Based upon a recent client study by Siemens which similarly addressed the rate impact of solar DER penetration on the utilities cost of service we found several anecdotal observations that support CUC's efforts to develop rate design strategies that simultaneously reward DER customers for avoided utility costs while mitigating cross subsidization by non-DER customers:

- A 10 percent penetration of residential solar DER was projected to cause an overall rate increase of 2 percent for that class of customers assuming no change in rate structure.
- For the residential class of service, non-DER participants would also experience an additional rate increase of up to 4.5 percent due to cross subsidization assuming intra class rate neutrality.
- While a recent cost of service study found that energy and demand allocation factors were equally proportional -- about 45 percent for each, incremental solar DER costs were 90 percent energy and 10 percent demand related. As a result, without a specific demand component, nearly all the DER costs would be passed through the energy charge while none of the demand related costs will be captured.

For CUC, "Base Case" annual revenue requirements exclude fuel costs which amounted to $155 million in Test Year ending 12/31/13 and represent approximately two thirds of total revenue requirements; i.e., $71 million (US$) electric sales and $155 million Fuel Factor. Excluding fuel costs from Base Case rates results in most of the remaining costs fixed as a function of demand. In December 2016, CUC commissioned a rate design study that developed a demand charge for both residential and commercial customers with Distributed Energy Resource, namely solar electric systems. The proposed demand based rate, included a two-tiered demand rate which offered customer savings resulting from reduced base generation capacity costs, while more accurately charging DER customers for reserve generation and fixed T&D costs. The proposed CUC Demand Rates was prepared by Utility Consulting Services for CUC and was based upon the 2014 Cost of Service Study that they had also performed by CUC. While we did not have the benefit of the cost of service model used to perform the 2014 COS Study or the demand rate analysis, the proposed demand rates appear to be based upon historical costs and are consistent with the objective to link rates to actual costs, i.e., cost causality.

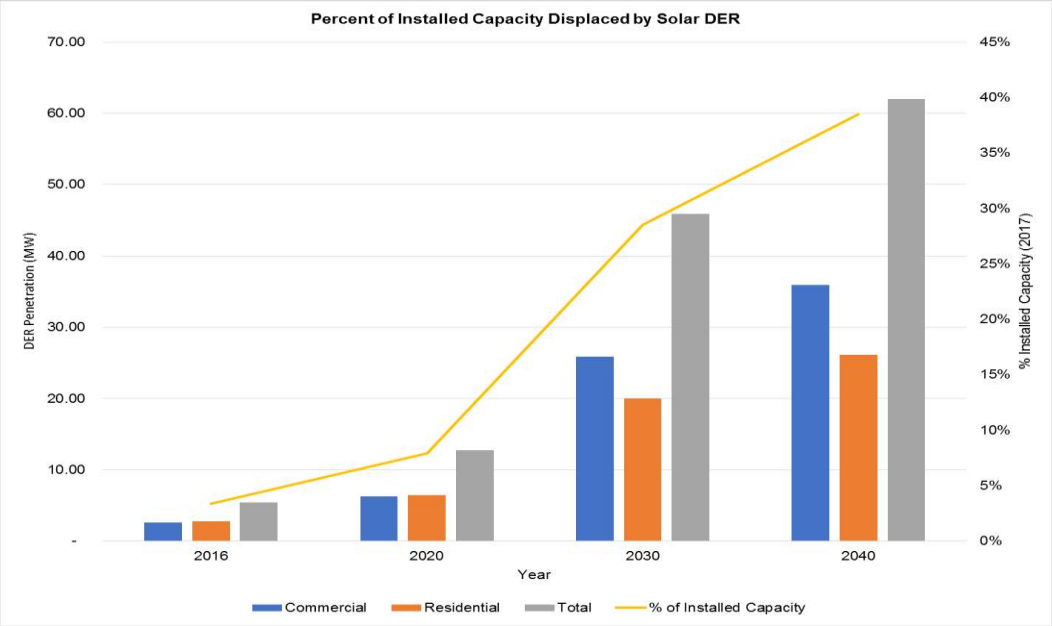
However, as illustrated below, in 2016 DER penetration represented about 1% of residential and commercial sales (Chart 12-1) and about 3 percent of displaced installed capacity (Chart 12-2). This represents a small proportion of either sales or surplus generation capacity and would have minimal impact on the reasonableness of the 2014 based cost of service analysis used to develop the proposed DER demand rates. Even by 2020, the DER penetration based on customer sales is only 2 percent, respectively and 8 percent based on displaced generation capacity. However, again, by 2030, commercial reduction will reach 10 percent and residential over 6 percent, and surplus generation capacity by approximately 30 percent. Between lower revenue recovery and greater levels of surplus capacity charged in rate base, would likely result in higher unit costs and the potential for rate base disallowances. In short, the proposed demand rate concept will likely remain valid for the next few years but will require a re-thinking as the penetration of DER increases within the next 5 years. We would further expect, that if CUC was able to recover the cost of generation displaced by DER penetration, non-DER customers would bear a greater proportion of fixed cost thereby subsidizing DER participants. This distortion would further bias costs such that non-participants would be incentivized to purchase a DER and the projected DER penetrations would be understated.

Exhibit 62: Projected Load Reduction Caused by DER



Source: Pace Global analysis

Exhibit 63: Percent Installed Capacity Displaced by DER



Source: Pace Global analysis

Findings and Conclusions

We found that the proposed changes in rate designs by the inclusion of a demand specific cost allocator (the *Proposed CUC Demand Rates* prepared by Utility Consulting Services) responds to the potential for over payment of net purchases by DER owners as well as the under recovery of demand related costs that are incurred by DER participants but not recovered via an energy only rate structure. Furthermore, consideration of short and longer term impacts that considers the customer's long term system demand benefits as well as the cost to provide backup services is a novel solution to the issues addressed above. In essence, the approach taken by Utility Consulting Services might be categorized as a "top-down" approach by retaining class based revenue neutrality and reallocating costs from energy-dominance to a more conventional energy and demand cost allocation scheme. As discussed above, Siemens found in its recent DER rate study that the costs and benefits associated with varying levels of customer owned DER was more complex than simply production offsets and demand allocation. We found that DER penetration also affected T&D investments, balancing charges, and production portfolio costs. As a supplemental analysis, we suggest that CUC employ a "Bottoms-up" analysis of DER system costs and benefits to quantify and validate the demand rate as proposed by CUC's rate consultant.

Recommendations for Future COSA

Pace Global was also asked to identify what CUC might do in its next COSA to improve its assessment of DER and other emerging technologies. Pace Global developed the following recommendations for the next CUC COSA:

- The cost allocation factors for both intra-class costs and inter-class costs are static and based on historical information. A future COSA should incorporate variable allocators based upon projected levels of DER penetration.

- Detailed information of class specific energy usage patterns is limited; it is difficult to assess the comparative customer demand on the CUC system versus the DER production cycle. Furthermore, sophisticated real-time metering data facilitate better estimates of the impact of net metering. For any future COSA, Pace Global recommends that CUC's AMI network be used to evaluate comparative usage patterns especially before and after a customer installs a DER system.

- The 2014 COSA did not clearly reflect economic and social policy objectives in designing forward looking retail rates. CUC should include an assessment of longer range goals and objectives as to load growth, environmental protection and energy management as part of its COSA assessment.

APPENDIX III: LOAD FORECAST DETAILS

METHODOLOGY OVERVIEW

Pace Global developed a deterministic reference case load forecast for CUC. The load forecasting process takes into consideration the historical relationship between demand growth, weather and economic variables, which are the key drivers of load growth, as well as adjustments for other drivers including customer additions, energy efficiency, DSM penetration, and electric vehicle usage. The forecast was performed according to the following process:

Step 1: Perform econometric analysis on core load drivers:

a) Build the relationship between demand and weather
b) Perform econometric assessment of the influence of economic variable(s) on demand growth
c) Incorporate customer count changes across each of the classes: namely residential, commercial and public lighting segments.

Step 2: Produce a load forecast based on the projections for each of the driver variables:

a) Used "Rank & Average" Technique to generate a normal weather projection
b) Used Strategic Planning report issued by the Government of Cayman islands
c) Incorporate known customer count additions in the service territory.

Step 3: Incorporate "one-off" developments such as:

a) Degree of Energy Efficiency Penetration levels
b) Expected increase in Plug-in Hybrid Electric Vehicles (PHeV)[35]

These effects are not reflected in the historical data. Based on publicly available reports and available data, the one-off development factors are quantified and used to adjust the forecasts from step 2.

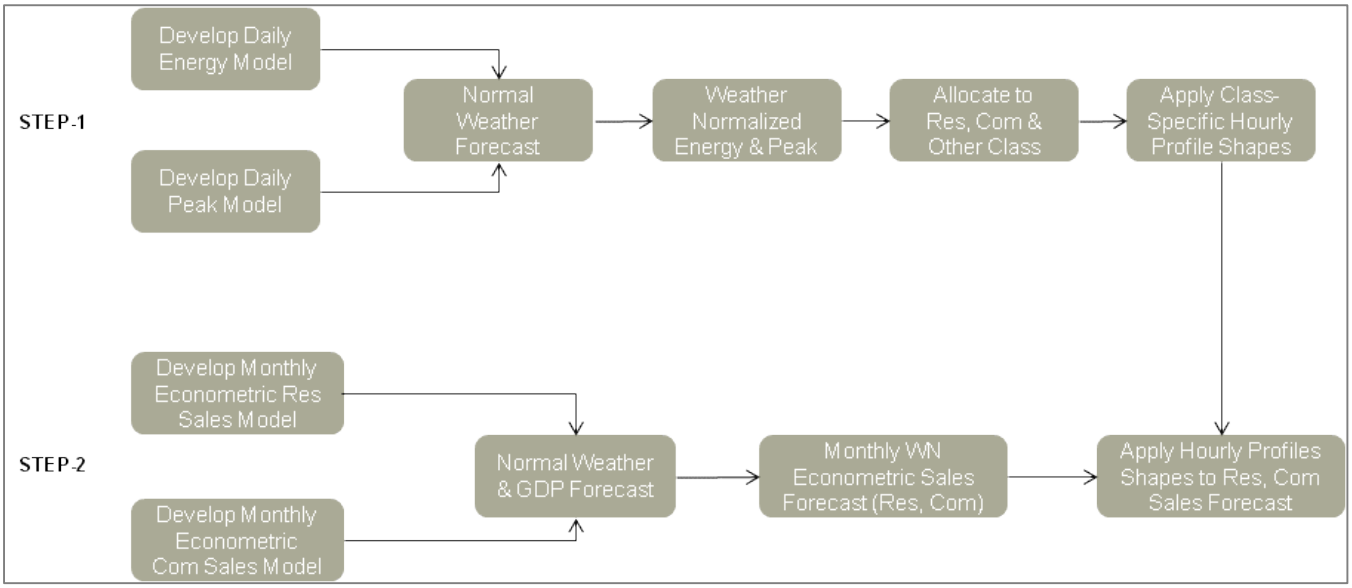
DEMAND FORECASTING PROCESS

Pace Global's demand forecasting process starts with analyzing the historical relationships between the actual load versus a combination of weather and calendar variables. There is no fixed methodology for load forecasting. Often, the methodology is based on availability of utility data and reasonable assumptions to fill in data gaps.

For this study, Exhibit 64 below shows the flowchart, depicting the load forecasting process.

[35] Demand from PHEV was found to be low and not considered as part of the forecast.

Exhibit 64: Demand Modeling Process



Source: Pace Global

The following section provides a description of the demand forecasting process. The forecasting methodology involves a 2-step process:

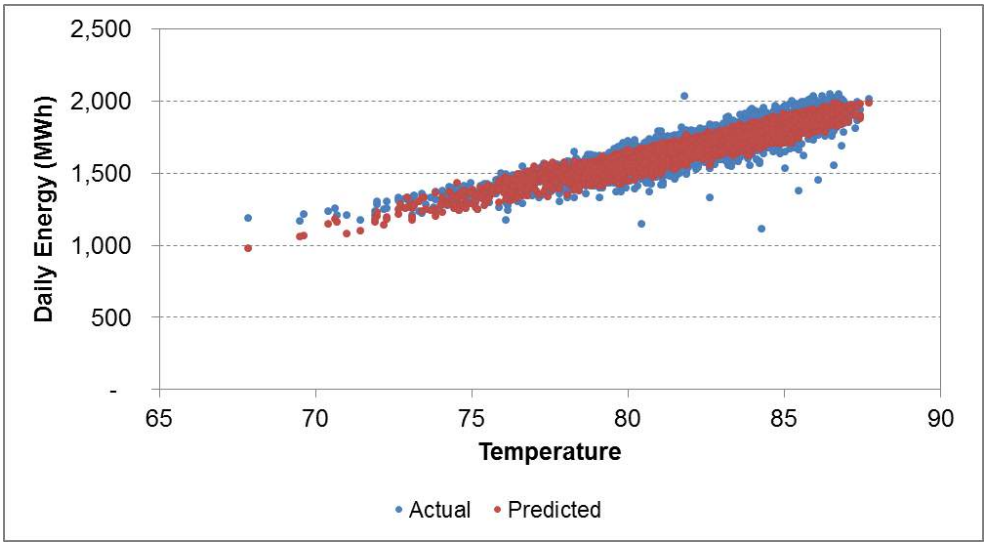
<u>Step-1</u>:

- Daily energy and daily peak load weather response functions were developed at the overall system level using six years of historical system wide load data from 2011-2016 provided by CUC. Exhibit 65 and Exhibit 66 show the model fit for the weather response functions. The generic form of the model structure is as given below:
    - Energy : *Function1(Temp, Humidity, Weekdays, Weekends, Lag_temp)*
    - Peak : *Function2(Temp, Humidity, Weekdays, Weekends, Lag_temp)*
- Develop normal weather forecast using 10-years of historical weather data. Exhibit 67 shows the weather normal forecast generated for this study.
- The system-level load was allocated to residential, commercial and lighting classes using pre-determined ratios.
- Pace Global obtained actual meter data from Oct-2015 till Sep-2016 for the residential and customer classes. The dataset has 21721 Residential and 3728 Commercial meters' hourly consumption (kW) data, for one full year. The hourly profile shapes were extracted after performing profile shape analytics on the data sets. Exhibits 69 – 72 show the hourly profile shapes for residential and commercial meter readings, categorized by month. The profile shapes differ by weekday and weekends.

Step-2:

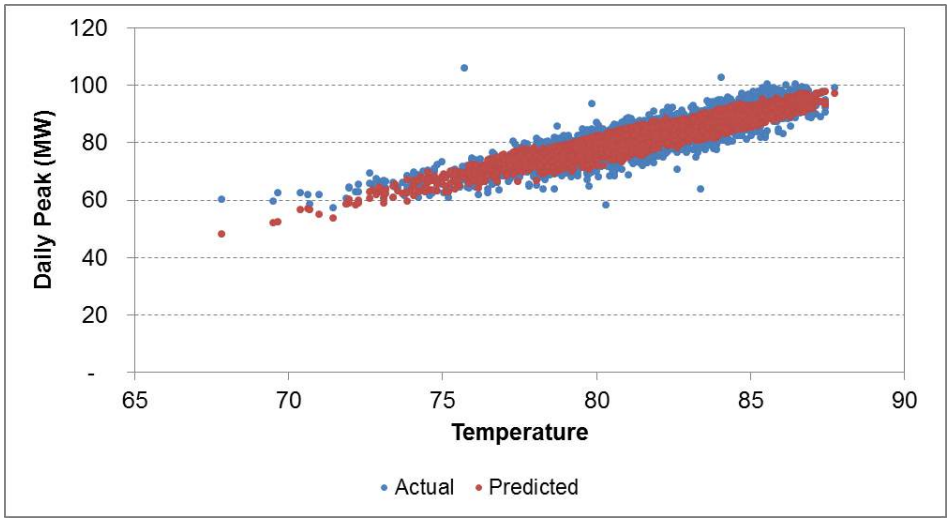
- Monthly econometric models were developed for residential and commercial energy sales separately. The generic form of the model structure is as given below:
    - Residential : *Function3(GDP, Temp, Humidity, Rainfall, Seasonal, Lag_temp)*
    - Commercial : *Function4(GDP, Temp, Humidity, Rainfall, Seasonal, Lag_temp)*
- GDP was used as the economic indicator variable. For the initial years, Pace Global considered the GDP forecast specified in the report "*2016/17 Strategic Policy Statement*". Exhibit 72 shows the GDP forecast used for this study.
- Using the monthly models, a forecast of residential and commercial energy growth rates were derived for the IRP study period. Exhibit 73 and Exhibit 74 show the forecasted monthly residential and commercial energy forecasts.
- As the last step, the hourly profile shapes from step 1 were applied to the monthly residential and commercial energy forecasts to obtain the final hourly forecasts.
- Lighting energy is assumed to go down over time, from the current 1% of total system energy level to less than 0.6% beyond 2025. This is due to energy efficiency measures under-taken by the utility in terms of deploying LED installations.

Exhibit 65: Daily Energy Model



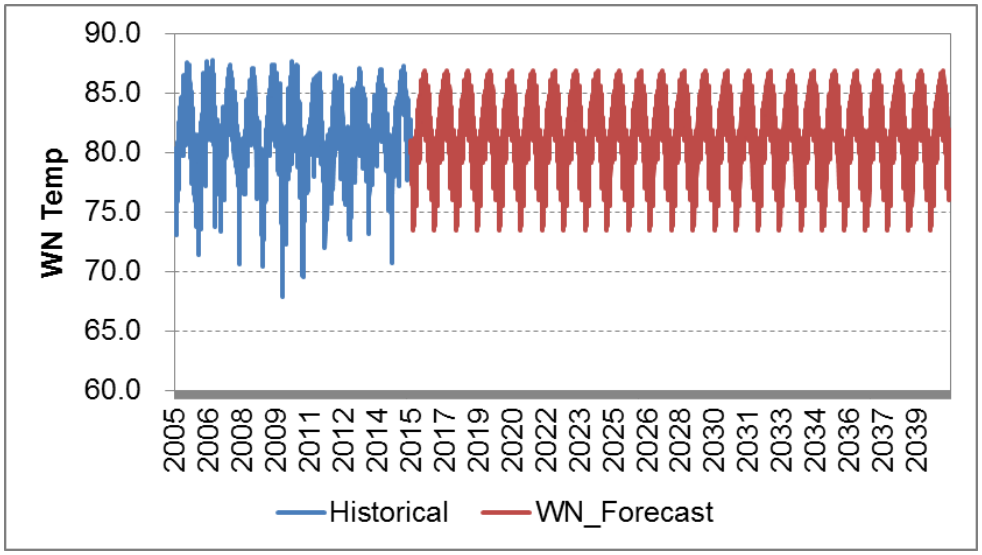
Source: CUC, Pace Global

Exhibit 66: Daily Peak Model



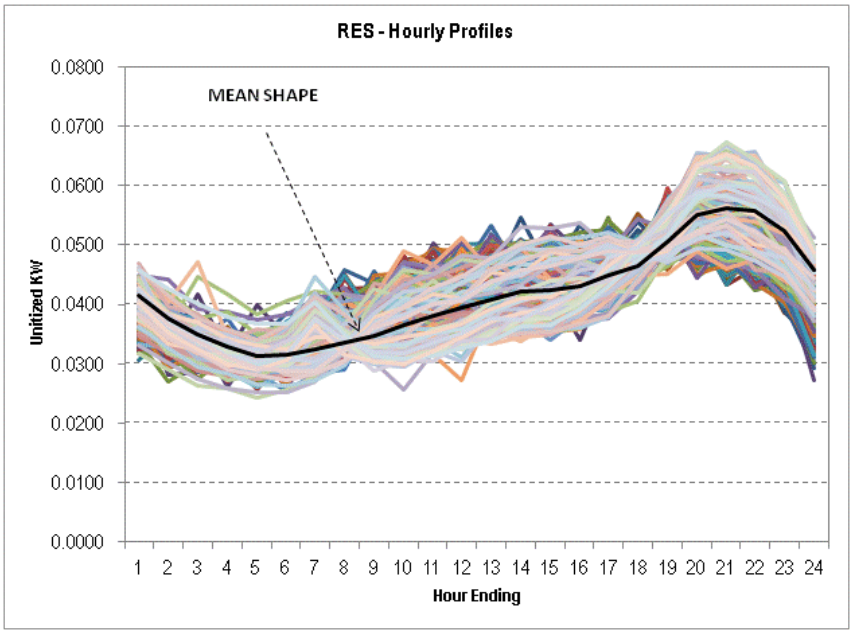
Source: CUC, Pace Global

Exhibit 67: Normal Weather Forecast



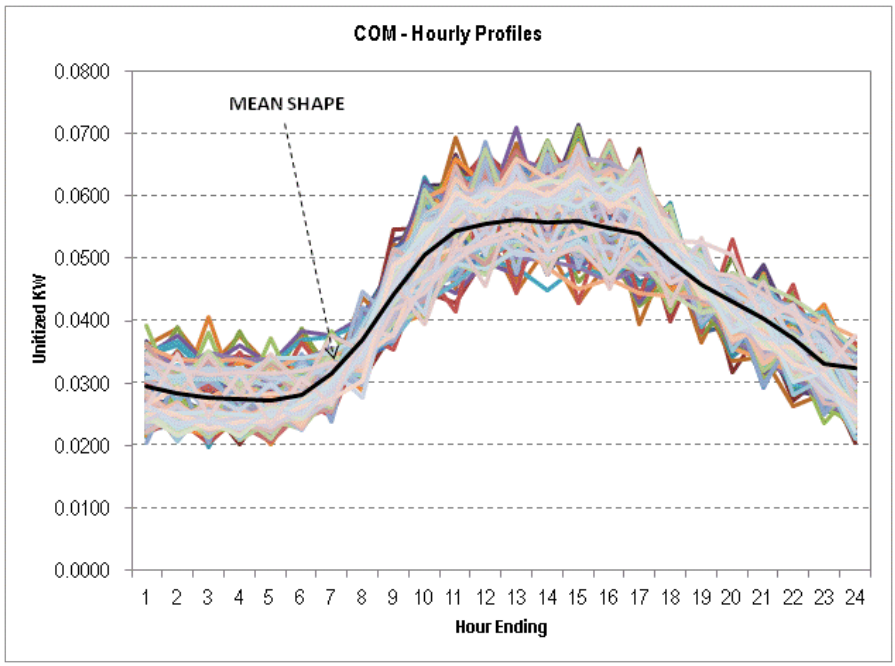
Source: CUC, Pace Global

Exhibit 68: Residential Meter Reading – Hourly Profile Variations



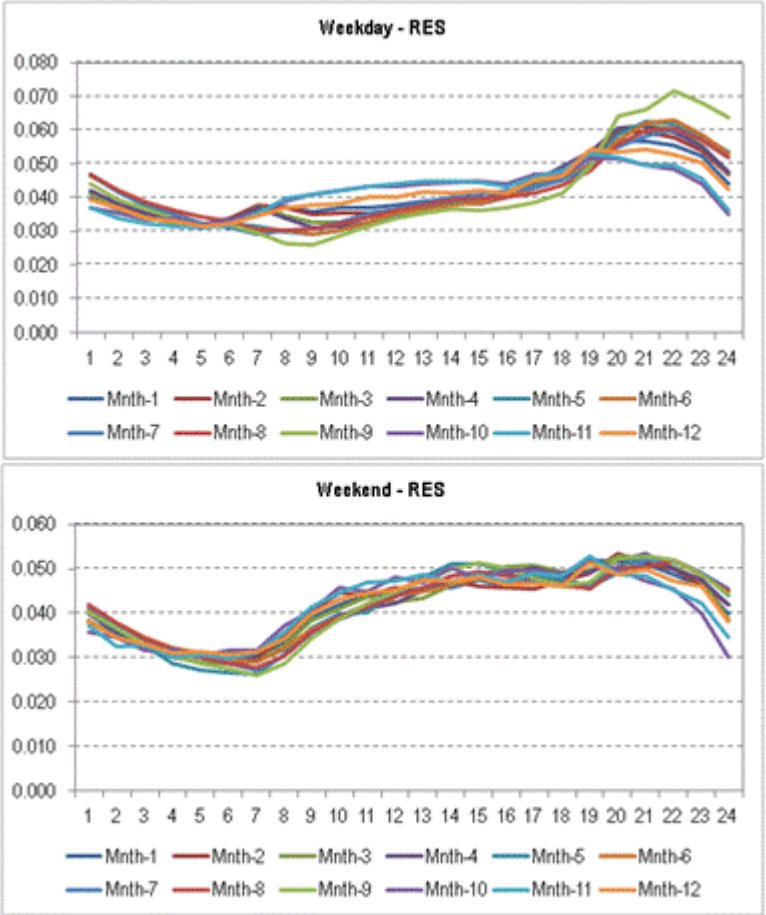
Source: CUC, Pace Global

Exhibit 69: Commerical Meter Reading – Hourly Profile Variations



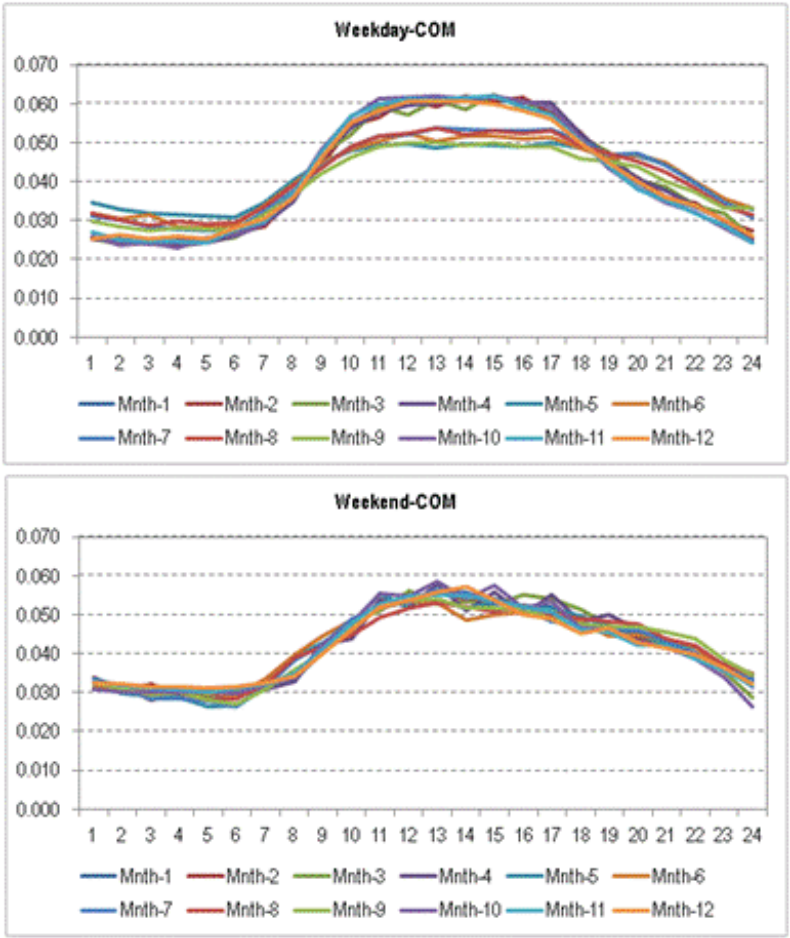
Source: CUC, Pace Global

Exhibit 70: Residential Meter Reading – Weekday vs. Weekend Hourly Profile Variations



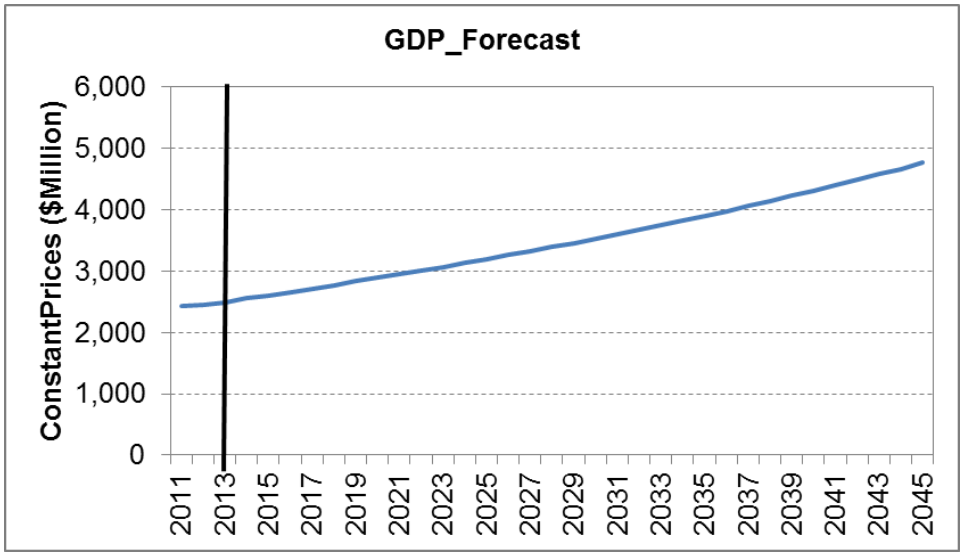
Source: CUC, Pace Global

Exhibit 71: Commercial Meter Reading – Weekday vs. Weekend Hourly Profile Variations



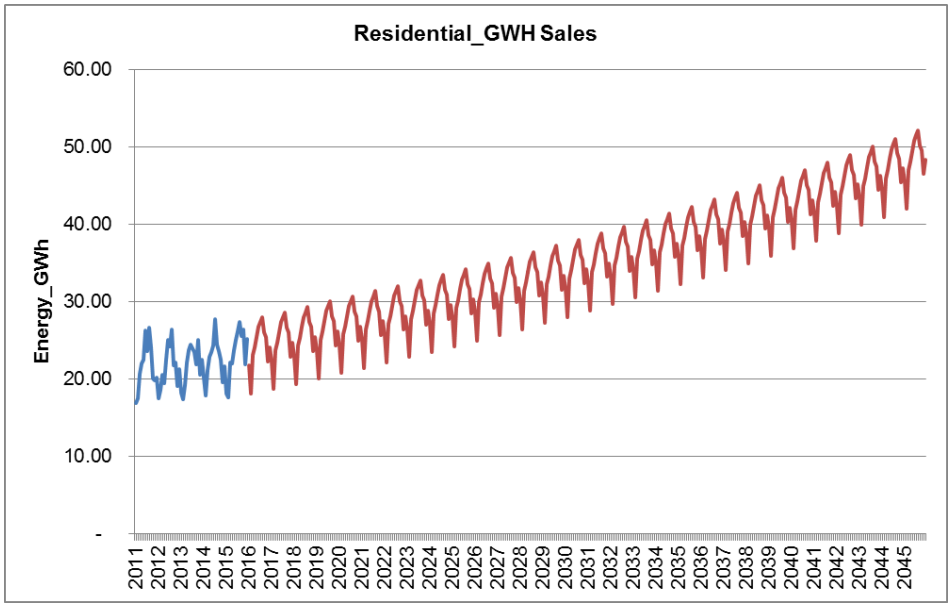
Source: CUC, Pace Global

Exhibit 72: GDP Forecast



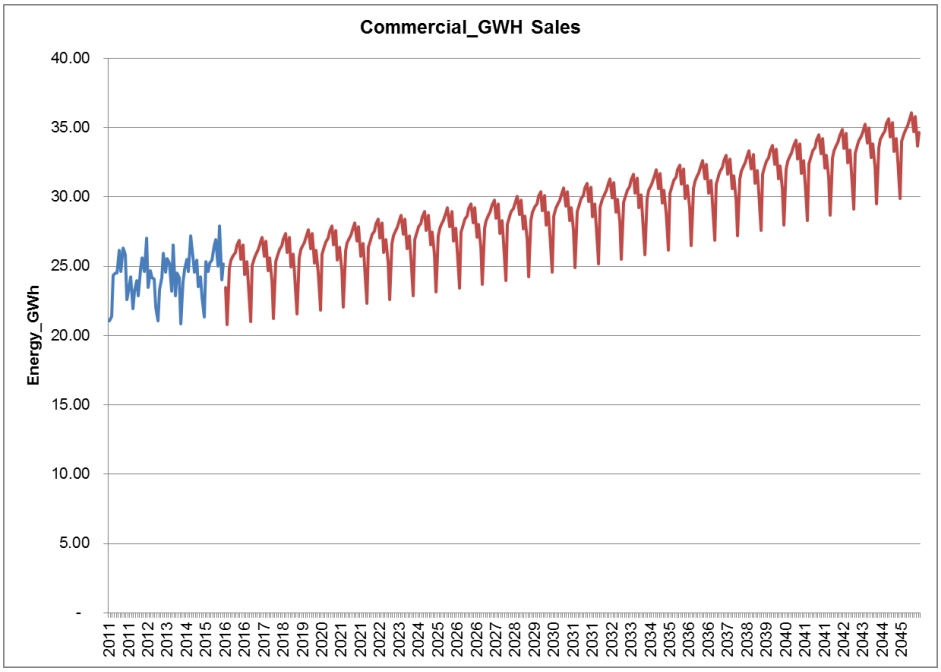
Source: Cayman Islands Compendium of Statistics, 2015, and 2016/2017 Strategic Policy Statement Document issued by Ministry of Finance and Economic Development

Exhibit 73: Residential Energy Forecast – Monthly (GWh)



Source: CUC, Pace Global

Exhibit 74: Commercial Energy Forecast – Monthly (GWh)



Source: CUC, Pace Global

KNOWN CUSTOMER ADDITIONS

Pace Global obtained the data regarding new customer additions from CUC, which are either under construction or expected to be online over the next 5 years. Majority of the new additions are Commercial. Pace made the following assumptions for the load forecast:

- All projects (Residential and Commercial) which are "under construction" were assigned a probability of 100%, for the projects to materialize and come online.
- For 2017, projects which are "not started" have been assigned a probability of 75%; which means 75% of the projects will come online and thus factored-in 75% of the corresponding MW load.
- For 2018, 50% of the projects which have the status "not started" are expected to come online.
- For these 2 years (2017 and 2018), the remaining growth will be determined by the GDP coefficient. For example, for 2018, since we have factored in the known additions with a weight of 50%, the remaining 50% energy growth will be determined by the GDP growth.

Exhibit 75 shows the new additions by year.

Exhibit 75: New Customer Additions – Energy (GWh) and Peak (MW)

Summary of Energy (GWh) Additions	Residential	Commercial
Additions_2016		0.6
Additions_2017	0.41	0.43
Additions_2018		0.67

Summary of Peak (MW) Additions	Residential	Commercial
Additions_2016		1.25
Additions_2017	0.85	0.89
Additions_2018		1.39

Source: CUC, Pace Global

WEATHER NORMALIZED LOAD FORECAST (OUTPUT)

The final step in the demand forecasting process is to apply the class-wise hourly profiles shapes to the forecasted residential and commercial class energy forecasts. Lighting load is extremely small; Pace applied the residential profile shape to convert the monthly lighting energy to an hourly load. Combining the hourly load across the three customer classes resulted in an hourly system-wide load forecast from 2016-2040.

The table in Exhibit 76 shows the Compounded Annual Growth Rates (CAGR) for the average and peak load forecasts (which were determined from the system-wide hourly forecasts). For the initial years (2016-2018), energy and peak growth is mainly driven by known new customer additions plus the growth determined by GDP. For years 2019 and beyond, GDP is the main driver for energy and peak growth.

Exhibit 76: Compounded Annual Growth Rates (CAGR) – Gross Load Forecasts

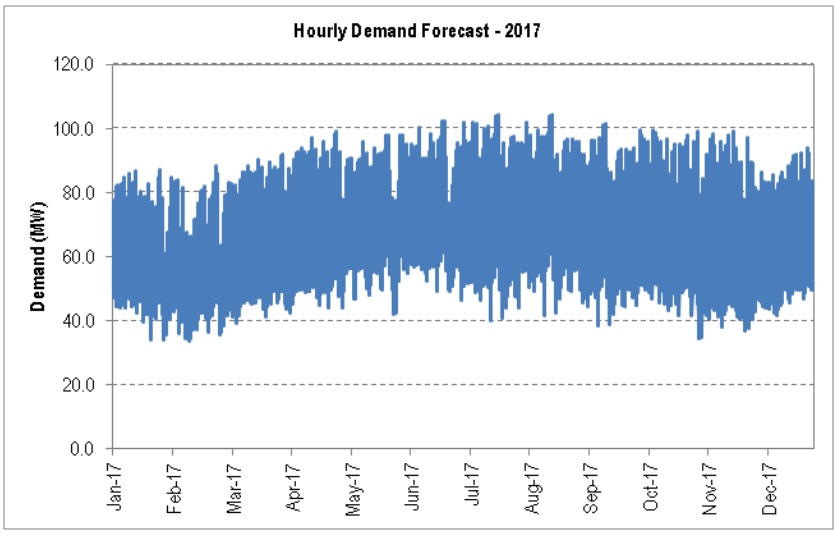
	Average Load (MW)	Peak Load (MW)
2016-2018	1.90%	2.39%
2016-2025	1.77%	1.70%
2016-2045	1.76%	1.56%

Source: Pace Global

HOURLY LOAD FORECASTS

The full output from the demand forecasting process consists of an hourly load forecasts from 2016-2040. Exhibit 77 shows a representative year's (2017) hourly load forecast, consisting of 8760 hours. The forecast thus obtained, is prior to adjustments for energy efficiency and other DSM measures.

Exhibit 77: Year 2017 - Hourly Load Forecasts

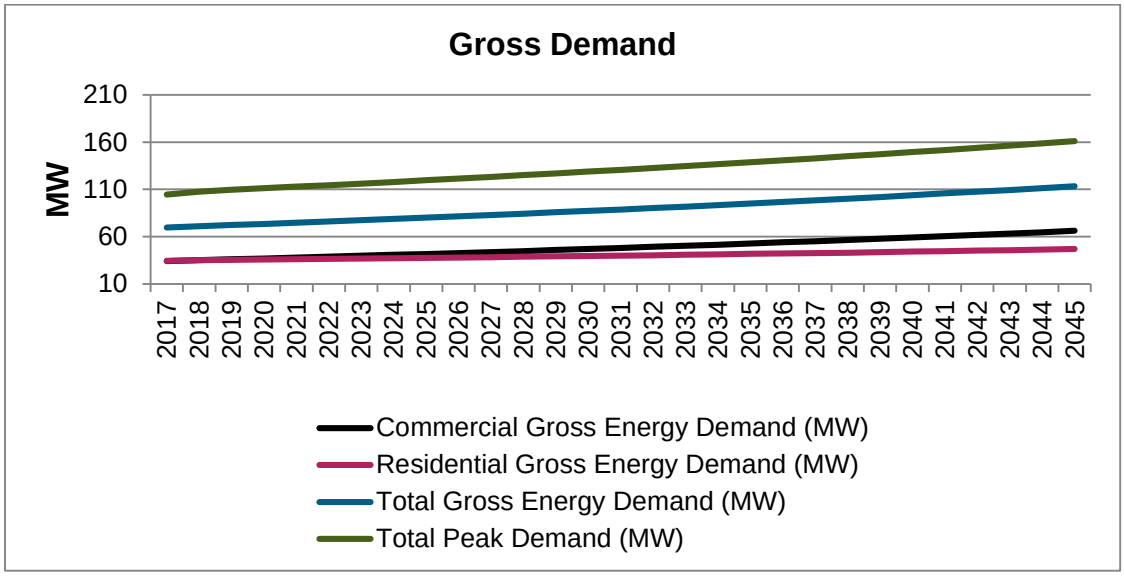


Source: Pace Global

GROSS LOAD FORECAST

Based on the methodology above, Pace Global developed a gross demand forecast at the system wide basis. Exhibit 78 shows the energy and peak demand forecast for the residential and commercial sector and aggregated at the system level

Exhibit 78: Gross Demand Forecast



Source: Pace Global

ENERGY EFFICIENCY ANALYSIS

The energy efficiency analysis was performed through a combination of bottoms-up analysis analyzing specific utility sponsored programs and relying on specific studies performed for the Cayman sponsored by the National Energy Policy group.

a) **Utility Sponsored Select Energy Efficiency Reductions** – Pace Global performed an analysis of utility sponsored programs analyzing a broad swath of energy efficiency programs. Of the programs considered, four programs on the residential side were eventually considered. The four residential energy efficiency programs considered were the residential lighting, residential air conditioning, residential ceiling insulation, and residential solar water heating program. Note that the residential lighting program is actually not a standalone program but part of an energy audit program. Business A/C and lighting programs were not considered as CUC had a general sense that many of the improvements have already been made.

In identifying the relevant programs, Pace Global analyzed programs FPL, TECO, and Duke Energy Florida each has a DSM program with a long history, well developed economic metrics, in a climate similar to the CUC territory. In addition, the consumption per capital is also similar to that for the Florida utilities. For these reasons, FL utility programs were evaluated as potential candidates for application in the Caymans.

For each of the four programs analyzed, Pace Global performed a total resource cost (TRC) test. The Total Resource Cost (TRC) Test measures the net cost of an energy conservation program, viewing the program as a utility resource option. Both utility and participant costs are included. The TRC Test reflects the impacts of a program on both participating and non-participating customers. Within the TRC cost analysis, revenue/bill costs and incentives intuitively cancel out. The test provides a measure of the cost-effectiveness of a **utility-sponsored** energy efficiency program.

The TRC is used in 35 US states with 10 states using it alone. It is the often the primary test in several jurisdictions and carries the largest weight. Utilities typically accept programs with TRC ratios > 1 but TRC < 1 may be acceptable for utilities targeting low income programs or pilot programs.

As shown in Exhibit 79, the TRC tests showed high cost effectiveness for residential lighting and residential air conditioning programs. The residential ceiling insulation program was marginal while the solar water heater program failed to pass the test. The test included an assessment of program costs, program benefits, including avoided fuel costs, avoided O&M costs, and avoided capacity costs. The penetration level for each program was based on projected penetration levels for Florida utilities with a slightly lower forecast as CUC does not currently of implementing and administering such programs.

Exhibit 79: Total Resource Cost Analysis Results

Program	Program Costs ($MM)	Program Benefit ($MM)	TRC	Net Benefit ($ MM)
Residential Lighting	0.4	4.4	11.15	3.59
Residential AC	1.3	3.4	2.54	1.57
Residential Ceiling Insulation	0.5	0.57	1.11	(0.15)
Solar water Heating	0.51	0.61	0.81	(0.20)

Source: CUC, Pace Global

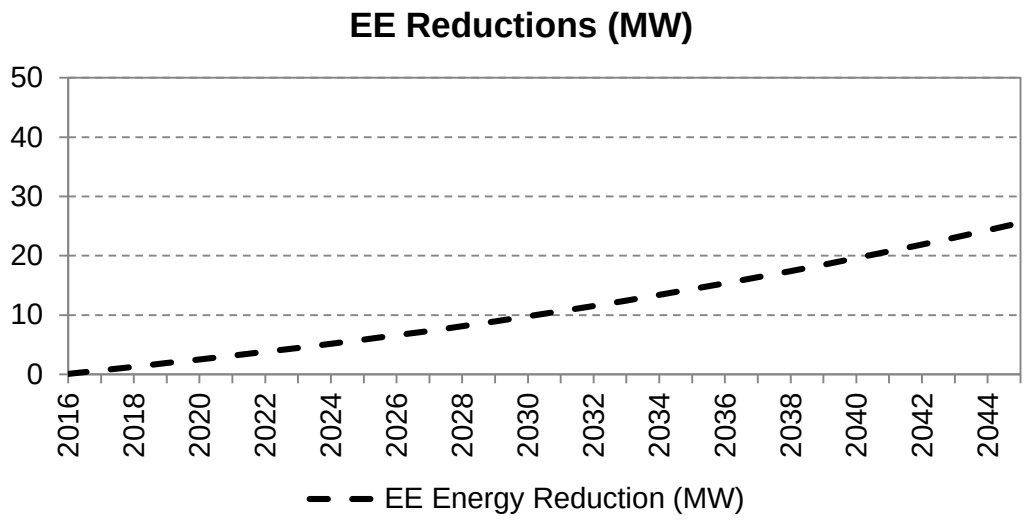
b) **Independent Energy Efficiency Analysis** – In addition to analyzing sample utility sponsored programs, Pace Global relied on an independent consultant report to the National Energy Policy for the energy efficiency penetration assumptions[36]. The report outlines a range of scenarios with varying energy efficiency penetration levels over the 2015-2037 period. Pace Global extrapolated the data beyond this time period for this analysis. The energy efficiency projection is shown in Exhibit 80. Pace Global assumed that in the Reference case 50% of economically viable energy efficiency investments are made. (the "Medium EE" case). The Medium EE inherently assumes a 16.5% reduction in energy demand from 2015 levels or a 0.73% a year reduction in demand over a 22 year period. While other penetration rates are possible, utilizing the Medium EE case appeared to be a reasonable assumption for the Reference case, based on energy efficiency penetration assumptions for other island IRP studies. [37]

Exhibit 80 shows the customer funded energy efficiency reductions assumed in the study.

[36] Report titled "Note on Updated Model of the Cayman Islands' energy sector, Report to the National Energy Policy Review Committee, Nov 22, 2016.

[37] Pace Global also reviewed energy efficiency assumptions made in other island IRPs. For example, the BELCO IRP assumed a 10% reduction over the first ten years and 20 years (for a reduction of 0.5% and 1.0% a year) while the Barbados IRP assumed a 22% reduction over a 16 year period. (1.38% a year)

Exhibit 80: Energy Efficiency Reductions (Average Energy)

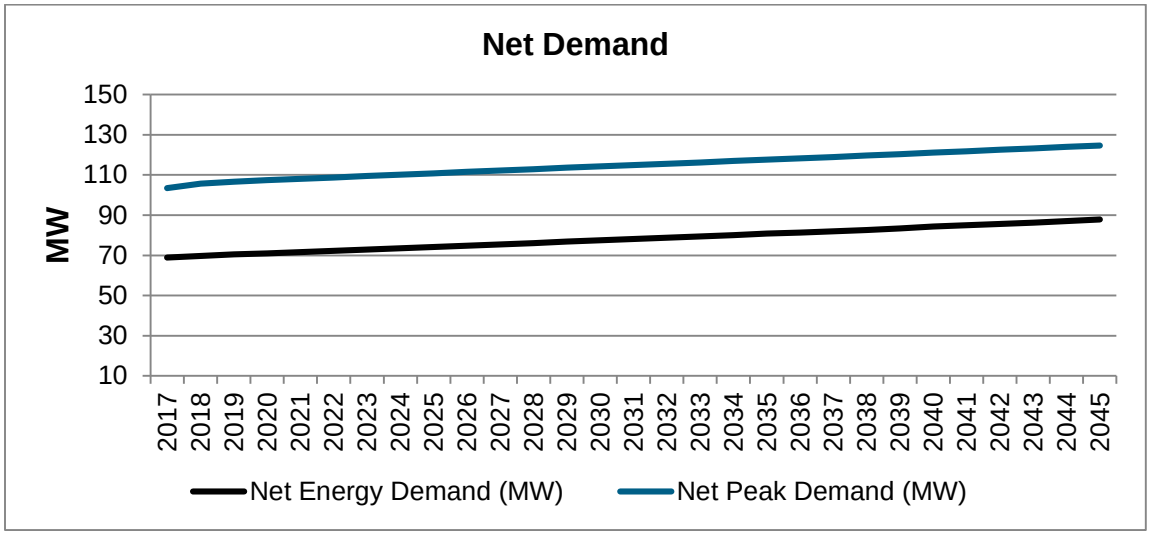


Source: Pace Global

NET LOAD FORECAST

The Exhibit 81 below shows the net energy and peak demand forecast taking into account the energy efficiency adjustments.

Exhibit 81: Net Load Forecast



Source: Pace Global

APPENDIX IV: SIGNPOST AREAS

The intent of this chapter is to identify "sign posts" that will trigger either a new IRP or steps that need to be taken to prepare CUC if certain events take place. For example, we know that at some point of renewable development, a deeper assessment of renewable integration on the grid may be necessary. Pace Global will identify metrics for when deeper analysis must occur. As shown in Exhibits 1 and 6, short term and long term action plans have been identified along with an indication of when additional studies might be completed. Further, signpost strategies have been identified to identify alternative course of actions should the primary set of strategies hit an impediment. The discussion below provides a more detailed perspective on each action.

TECHNOLOGY CHOICES AND DECISIONS

- The IRP analysis assumes that the new reciprocating engines will be flexible and be able to operate at a minimum operating level of 30%. Given high penetration levels of renewables, it is recommended that future thermal generation procurements target such flexible capacity resources. The current fleet has operating limitations where-in the minimum operating levels are approximately 65%. This limits the plant from providing adequate downward ramping to accommodate renewable generation. Furthermore, a high operating set point may provide limited flexibility to the units to provide spin and regulation services.

RENEWABLE INTEGRATION ISSUES

The island will require large amounts of intermittent renewables in order to meet the carbon emission reduction goals. To address planning and operational challenges associated with the renewable generation, CUC may need to perform additional assessments.

- The IRP analysis showed that utility scale wind and solar curtailments are likely to happen. While curtailments can be managed to a large extent through energy storage, it is not possible to eliminate all curtailments without incurring large costs. Hence, there is a trade-off between reducing curtailments and incurring capital costs. Curtailment risk can be a reality especially in the long term and needs to be managed appropriately. It is recommended that CUC put together a curtailment methodology in place by the 2020 period.
- The IRP analysis is conducted at an hourly level. However, many of the operating reserves related issues associated with intermittent renewable resources are sub-hourly in nature. It is recommended that CUC consider a separate analysis analyzing sub-hourly operational issues prior to investments in storage and new thermal generation capacity.

DISTRIBUTED GENERATION INTEGRATION ISSUES

The IRP assessment projects a distributed solar penetration level of approximately 45 MW by 2030 and 70 MW by 2045. The growth trajectory of distributed solar can be steep as has been experienced in many parts of the world, including the United States. In order to safely integrate distributed solar,

- Perform hosting capacity analysis to determine which feeders can support more solar relative to the others.

DEMAND SIDE ISSUES

- A robust analysis has been performed on the demand side. However, Pace Global suggests that CUC should monitor developments in electric vehicle penetration and determine if the penetration rates are likely to be higher than currently envisioned.
- The ability of specific demand side programs to reduce peak demand should be looked at more thoroughly. Additional applications for demand response could be frequency response services. Such programs may defer or avoid the need for UVLS and UFLS schemes.
- The IRP analysis looked at a handful of energy efficiency and demand response programs. However, a more thorough analysis may need to done to determine the CUC may want to collect and assess market characterization data to have more complete information upon which to estimate costs and savings. This would lead to refined program models and very likely to some new candidate programs (maybe in the commercial segment). Overall better data gathering will result in better conclusions and this will lead to a more cost effective DSM portfolio for both the utility and the rate payers.

STORAGE OPTIMIZATION

- The selection of the energy storage size and timing of the build-out was based on an iterative approach given the limitations of the current production cost modeling framework to optimize storage with other generation resources. Prior to making a procurement decision, CUC may want to conduct additional analysis to fine-tune the storage selection. Furthermore, the analysis assumes adoption of the Li Ion battery technology given the current and expected cost profile. However, other battery energy storage technologies such as flow batteries can also be considered if competitive quotes can be received from the vendors.

FUEL OPTIONS AND RISKS

- CUC should begin the process of developing a plan to bring natural gas to the island. Quotes from vendors should be obtained and permitting steps undertaken. Given the projected diesel vs. natural gas prices, having natural gas on the island by the 2020/2021 appears to make economic sense. Having natural gas on the island and developing dual-fuel capability for thermal generators has significant benefits in terms of hedge against diesel price volatility and the optionality to burn multiple fuels from point of view on ongoing operations and for grid resiliency reasons. However, the exact timing of the natural gas infrastructure and any decision to build the actual infrastructure might be predicated on what the spot and forward prices look like in the future.
- Historically, diesel prices have shown more volatility compared to natural gas prices and this trend has been taken into account in the development of the commodity pricing bands for the scenario analysis. There are potentially other risks associated with international LNG market. These are being recognized in the IRP but quantification of the risks may be considered in another study.

GRID IMPACT ANALYSIS

- Much of the IRP analysis is agnostic to the exact location of the renewable assets within the East zone. Once more detailed siting and permitting analysis is conducted and an exact location determined, CUC would need to perform more detailed system impact studies looking at load flow, short circuit, and stability analysis to ensure that adequate grid capacity is available to support the renewable buildout. At that time, the location of storage can also be optimized as storage may be able to help provide with any fast frequency response, as needed.

APPENDIX V: LONG TERM CAPACITY EXPANSION LOGIC

In AURORAxmp, future resource units may be put in the database with pre-determined start dates. Or, you can use the long-term optimization logic that uses market economics to determine the long-term resources and the start or retirement dates. Long-term optimization studies are used to forecast capacity expansion resources and retirements. The current iterative energy valuation logic is discussed in this section.

AURORA performs an iterative future analysis where 1) resources that have negative going-forward value (revenues less cost) are retired and 2) resources that add value are added to the system. This is done on a gradual basis—where a set of resources with the most positive net present value are selected from the set of new resource options and added to the study. 3) AURORA then uses the new set of resources to compute all of the values again 4) The process of adding and retiring resources is repeated. This whole process is continually repeated until value or system price stabilizes indicating that an optimal set of resources is identified for the future conditions assumed for the study.

The competitive marketplace will construct resources over the long-term such that there is an expectation that the new resources will create value on a going-forward basis on average in the market areas where additional capacity is economically warranted. Likewise, existing resources that have no value on a going forward basis will eventually be retired within the constraints of the system unless they are identified as not being eligible to retire early. Existing and potential resources can be studied to see how well they will compete in the marketplace.

The goal of optimization process is to simulate the competitive marketplace by identifying the investments in future resources that have the value in the marketplace. AURORA assumes that new generators will be built (and existing generators retired) based on economics. The economic measure used is real levelized value (revenues less cost) on a $ per MW basis. Investment cost is included in the cost portion of the formula.

Also, the methodology assumes that potentially non-economic contracts will not influence the marketplace and that someone will capture the opportunity value of non-economic contracts. Therefore contracts are not modeled in the pricing piece of AURORA. However, the economics of contracts and resources may be evaluated in the Portfolio Analysis capability of AURORA.

In preparing for Long-term optimization studies, users will identify new resource options to be evaluated in the study and determine parameters for the study including any Operating Reserve Margin Premiums.

NEW RESOURCES

In the New Resources Table in the database is where the user defines a new resource and its operating characteristics. The types of resource may be existing technologies such as Wind, Solar, Nuclear, Coal, or Gas. Also, new resources may include improvements in the heat rates of existing technologies, re-deployment of existing resources, or emerging technologies.

The input on new resources defines the variables of a new unit, including when the potential unit will be placed in service. These variables provide controls for placing operating constraints on all the units in the system. AURORA will calculate a value for each unit. This value is a Real Levelized Net Present Value (NPV) in $/MW. The capital cost is part of Real Levelized cost. AURORA uses the Real Levelized cost per MW to make decisions about new units. Using this approach enables resources to be compared on equal basis with different capacity sizes and different investment lives. This also handles the economic comparisons when the resource end of life extends beyond study period.
Therefore, investors are compensated for their investment and the economic decision holds for not only the

study period but over the life of the resource project. The capital investment costs include:

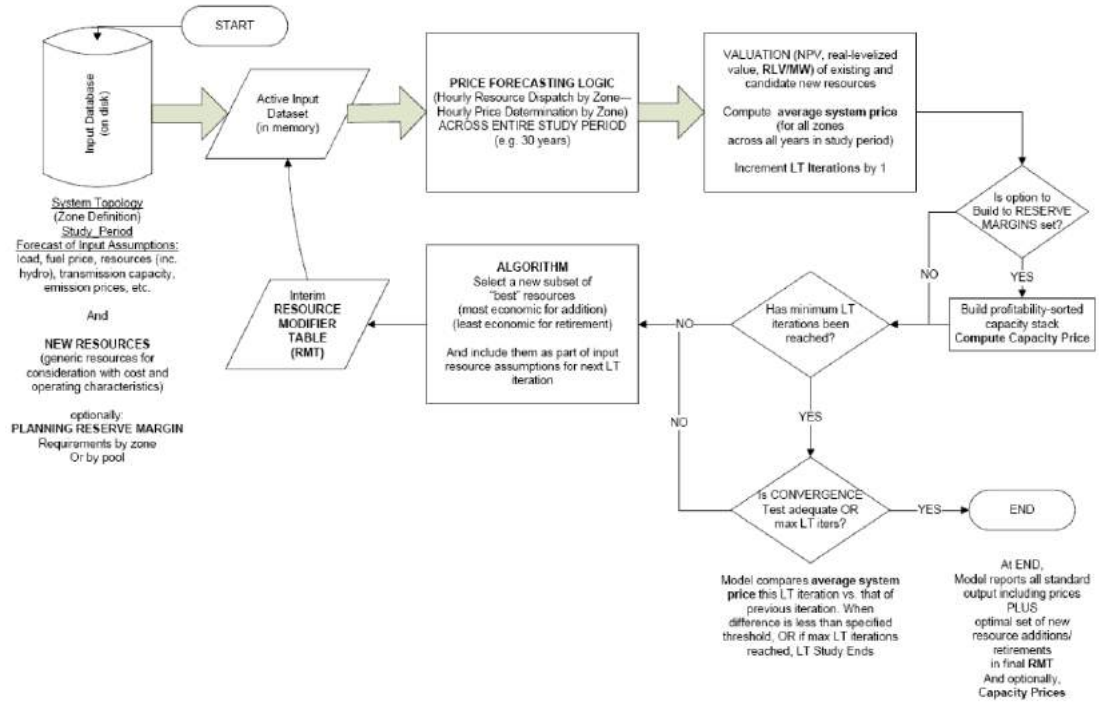
- Rate of Return of attract capital investment
- Capital Recovery
- Income Tax Costs and Benefits

These costs are entered into AURORA in real dollars terms, Constant Dollars. The capital costs are levelized in constant dollars over asset life to provide a correct measure of value for a period of time shorter than the asset life. This is important because the study period of the capacity expansion plan may be shorter than the asset lives of the new resources.

To illustrate the calculation of the capital investment costs, the investment carrying cost of a combined cycle gas turbine is described. The general assumptions include: the assumed general inflation rate and income tax rates. The cost-of-capital assumptions capture the return requirement of investors. In this example, the debt/equity structure is 60/40 and the equity return is 20 percent. Under these assumptions the After Tax Cost of Capital would be 11.4 percent and the Real After Tax Cost of Capital would be 8.7 percent (see table below).

Based on the assumed tax recovery period, e.g., 15 years for a combined cycle gas turbine unit (CCT), the Present Value factor is 1.299 for the Capital Carrying costs. In other words, 12.3 is the carrying-cost-rate that equal to an annuity of NPV (real) assuming an asset book life of 30 years. Therefore, if the Capital Investment for the CCT is $516 per KW, the Capital Investment Carry Cost related to the capital investment would be $1,223 per MW per Week.

Exhibit 82: Aurora Long Term Capacity Expansion Logic



Source: EPIS, LLC

MIXED-INTEGER PROGRAM LOGIC FOR LT

The long-term (LT) capacity expansion functionality in AURORAxmp includes the option to use a mixed-integer program (MIP) to make the resource build and retire decisions. The logic can be used with a target objective function of minimizing the total system cost or of maximizing the value of the resources being built and retired.

The MIP methods differ from the Traditional LT logic in several ways that will be discussed here. While the Traditional LT logic is generally the recommended approach, in some cases there are significant advantages to using one of the two MIP methods, including:

- Faster convergence
- A solution that gives lower total system cost to meet the requirements
- Improved stability, especially in Energy Only LTs
- Better handling of complex build and retire constraints

The general iterative methodology is the same for all LT methods. During each LT iteration, an updated set of candidate new resource options and retirements are placed in the system and the model performs the standard chronological commitment and dispatch logic with that configuration. The model tracks the performance of all new resource options and resources available for retirement, tracking the resource costs and value based on the market prices developed in the iteration. At the end of each iteration, the LT logic decides how to adjust the current set of new builds and retirements, or it determines that the model has converged and writes the final RMT with the decisions to the input database. The LT methods differ in how they determine the adjustment to the current mix of resources in the system each iteration.

In the two MIP methods (**Maximize Value** and **Minimize Cost**), the model formulates a mixed-integer program to make the resource selection. The decisions are done on a pool level if Operating Pools are being used. Both methods include constraints to honor these user-specified criteria:

Annual Min/Max and **Overall Min/Max** Limits - The model adds new resource constraints to ensure that both annual and overall min/max criteria on both a new resource as well as a new resource group basis are honored.

Reserve Margin Targets - The model ensures that the zone and pool based reserve margin constraints defining the minimum capacity that must be available for reliability are met.

Retirement Limits - The model adds constraints to ensure that the model retires units only within the timeframe specified in the Resources table. It also ensures that the total annual retirements are limited by the limit specified for each pool. Because pools are solved individually, the global retirement limit may not be honored, but the model will ensure that it is met for each pool individually.

LT Energy Min Constraints - If the user has defined minimum energy constraints for the LT in the Constraint table, the model will add these to the MIP to optimize the selection of resources in order to satisfy the target values.

Retrofit Constraints - Constraints are added to the model to facilitate the analysis of retrofit units. These constraints ensure that only one of the options (the original resource or a retrofitted resource in a given year) is available to the system at any point in time. If any constraints are deemed infeasible (e.g. the

reserve margin cannot be met with the available resources) the model will use intelligent infeasibility handling to relax those constraints as little as possible.

For the Minimize Cost method, the formulation also includes the following constraints:

Energy Targets - Energy constraints are used to ensure that all energy needs are met. The model adds both pool and zone constraints to ensure that the required energy for each is satisfied. In order to make the problem manageable, the energy constraints and variables are aggregated into bins every year: 1 bin if using low LT Study precision, 3 for medium, and 5 for high. These bins are defined as equal ranges between the minimum and maximum sampled demand for the month being run.

Peak Net Load Constraints - The model will determine the annual peak net load and will add a corresponding constraint to ensure there is sufficient capacity available to meet that hour's demand.

Curtailment Constraints - During each iteration of the LT, the model tracks the usage of demand curtailment units. For each hour that curtailment resources are utilized, the model will add a constraint that ensures there is sufficient non-curtailment capacity available to meet that hour's demand.

APPENDIX VI: PORTFOLIO RESULTS SHEETS

Portfolio 1 Base		Fiscal Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
COST	**Unit**																														
Total Costs	***$000***		**107,318**	**116,704**	**123,111**	**123,480**	**120,250**	**115,341**	**117,007**	**118,225**	**117,555**	**118,639**	**121,117**	**121,690**	**125,563**	**126,607**	**127,612**	**127,472**	**130,095**	**130,535**	**133,878**	**134,723**	**137,742**	**138,908**	**140,298**	**142,034**	**143,001**	**144,314**	**146,168**	**147,961**	**149,116**
Fuel Costs	*$000*		84,035	92,066	97,381	83,959	73,339	64,675	61,951	61,179	61,151	61,079	61,754	63,020	62,208	63,203	64,146	65,418	66,331	67,245	67,980	69,160	70,153	71,255	72,590	74,074	75,184	76,414	77,516	79,109	80,437
Fixed Costs	*$000*		7,189	7,189	7,189	9,903	10,647	10,904	11,814	12,137	11,746	11,820	12,214	11,943	12,777	12,777	12,777	12,263	12,732	12,413	13,022	12,869	13,450	13,450	13,450	13,487	13,361	13,285	13,464	13,501	13,464
Variable Costs	*$000*		1,779	1,783	1,795	1,921	1,717	1,540	1,490	1,469	1,456	1,450	1,459	1,475	1,451	1,461	1,471	1,485	1,494	1,500	1,507	1,520	1,529	1,541	1,556	1,575	1,583	1,594	1,605	1,622	1,632
CAPEX (New & Existing Units)	*$000*		14,315	15,666	16,746	27,697	34,548	38,222	41,752	43,440	43,203	44,290	45,691	45,252	49,128	49,167	49,219	48,306	49,538	49,377	51,369	51,174	52,610	52,662	52,701	52,898	52,874	53,020	53,583	53,730	53,583
$/KWh Costs			0.16	0.17	0.18	0.18	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
NPV ($1000), Discount Rate 5.5%	***$1,788,127***																														
ENVIRONMENTAL COMPLIANCE																															
Emissions Amounts (CO2 Tons)	*Tons*		*443,235*	*444,378*	*447,477*	*379,157*	*328,743*	*287,992*	*274,109*	*269,023*	*267,295*	*265,373*	*266,618*	*270,411*	*265,257*	*267,804*	*270,092*	*273,704*	*275,737*	*277,763*	*278,977*	*282,054*	*284,376*	*287,271*	*291,092*	*295,458*	*297,705*	*300,402*	*302,509*	*306,462*	*309,346*
Emission Compliance Target (CO2 Tons) Only for 4-6	*Tons*		*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Renewable Penetration (generation basis)	*percent*		*2.25%*	*3.20%*	*3.58%*	*18.92%*	*30.07%*	*39.53%*	*42.70%*	*44.42%*	*45.22%*	*45.87%*	*45.89%*	*45.79%*	*47.19%*	*47.11%*	*47.05%*	*46.99%*	*46.81%*	*46.95%*	*47.12%*	*47.03%*	*46.88%*	*46.77%*	*46.57%*	*46.43%*	*46.35%*	*46.25%*	*46.21%*	*46.12%*	*45.94%*
Operating Costs Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Fuel	$000		**84,035**	**92,066**	**97,381**	**83,959**	**73,339**	**64,675**	**61,951**	**61,179**	**61,151**	**61,079**	**61,754**	**63,020**	**62,208**	**63,203**	**64,146**	**65,418**	**66,331**	**67,245**	**67,980**	**69,160**	**70,153**	**71,255**	**72,590**	**74,074**	**75,184**	**76,414**	**77,516**	**79,109**	**80,437**
Existing	$000		84,035	92,066	97,381	83,959	73,339	64,675	55,134	54,010	52,656	48,587	47,405	47,224	44,109	44,653	45,168	40,893	38,442	32,568	28,589	28,935	29,009	29,244	29,477	29,771	14,303	-	-	-	-
New	$000		-	-	-	-	-	-	6,817	7,169	8,495	12,492	14,349	15,796	18,099	18,550	18,977	24,525	27,889	34,677	39,392	40,225	41,144	42,011	43,113	44,303	60,881	76,414	77,516	79,109	80,437
Fixed Costs	$000		**7,189**	**7,189**	**7,189**	**9,903**	**10,647**	**10,904**	**11,814**	**12,137**	**11,746**	**11,820**	**12,214**	**11,943**	**12,777**	**12,777**	**12,777**	**12,263**	**12,732**	**12,413**	**13,022**	**12,869**	**13,450**	**13,450**	**13,450**	**13,487**	**13,361**	**13,285**	**13,464**	**13,501**	**13,464**
Existing Units	$000		7,189	7,189	7,189	7,209	7,189	6,487	6,207	6,224	5,749	4,919	4,331	4,039	3,710	3,710	3,710	3,171	2,861	2,443	2,147	1,964	1,772	1,772	1,772	1,777	879	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	804	806	804	1,607	2,589	2,596	3,393	3,393	3,393	3,402	4,196	4,196	5,000	5,013	5,803	5,803	5,803	5,819	6,607	7,410	7,589	7,610	7,589
DG Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	$000		-	-	-	482	962	1,343	1,343	1,346	1,443	1,543	1,543	1,548	1,924	1,924	1,924	1,929	1,924	2,024	2,125	2,131	2,125	2,125	2,125	2,131	2,125	2,125	2,125	2,131	2,125
Utility Wind	$000		-	-	-	-	290	869	1,255	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544
Waste to Energy	$000		-	-	-	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025
Landfill Gas	$000		-	-	-	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181
Variable O&M	$000		**1,779**	**1,783**	**1,795**	**1,921**	**1,717**	**1,540**	**1,490**	**1,469**	**1,456**	**1,450**	**1,459**	**1,475**	**1,451**	**1,461**	**1,471**	**1,485**	**1,494**	**1,500**	**1,507**	**1,520**	**1,529**	**1,541**	**1,556**	**1,575**	**1,583**	**1,594**	**1,605**	**1,622**	**1,632**
Existing Units	$000		1,779	1,783	1,795	1,525	1,323	1,155	983	957	924	851	827	819	761	765	769	691	647	544	475	478	476	477	479	481	232	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	122	127	149	219	251	274	312	318	323	414	469	579	654	664	675	686	700	715	973	1,217	1,227	1,243	1,254
DG Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Wind	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	$000		-	-	-	336	335	327	327	327	324	323	323	324	321	321	321	322	321	321	320	321	320	320	321	321	321	321	321	322	321
Landfill Gas	$000		-	-	-	60	59	58	58	58	58	57	58	58	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57	57
CAPEX (Ammortized)			**14,315**	**15,666**	**16,746**	**27,697**	**34,548**	**38,222**	**41,752**	**43,440**	**43,203**	**44,290**	**45,691**	**45,252**	**49,128**	**49,167**	**49,219**	**48,306**	**49,538**	**49,377**	**51,369**	**51,174**	**52,610**	**52,662**	**52,701**	**52,898**	**52,874**	**53,020**	**53,583**	**53,730**	**53,583**
CAPEX (Total Spend)			**25,950**	**13,348**	**14,386**	**144,864**	**84,681**	**80,065**	**61,832**	**30,009**	**21,117**	**43,960**	**42,157**	**8,409**	**63,188**	**7,329**	**7,329**	**7,329**	**30,536**	**12,948**	**36,117**	**4,242**	**28,186**	**3,501**	**3,501**	**3,501**	**27,989**	**24,438**	**7,295**	**-**	**-**
Existing Units	$000		12,958	13,348	14,386	14,699	15,629	14,204	12,264	12,264	12,264	10,103	9,441	8,409	7,329	7,329	7,329	7,329	5,653	5,653	4,242	4,242	3,501	3,501	3,501	3,501	3,501	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	25,386	-	-	25,234	32,716	-	25,083	-	-	-	24,883	-	24,783	-	24,684	-	-	-	24,487	24,438	7,295	-	-
DG Solar	$000																														
PV Solar	$000		12,993	-	-	53,686	49,680	37,506	-	-	8,853	8,624	-	-	30,776	-	-	-	-	7,295	7,092	-	-	-	-	-	-	-	-	-	-
Utility Wind	$000		-	-	-	-	19,373	37,355	24,183	17,745	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	$000		-	-	-	73,820	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Landfill Gas	$000		-	-	-	2,659	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conversion Costs	$000																														
TOTAL COST	**$000**		**107,318**	**116,704**	**123,111**	**123,480**	**120,250**	**115,341**	**117,007**	**118,225**	**117,555**	**118,639**	**121,117**	**121,690**	**125,563**	**126,607**	**127,612**	**127,472**	**130,095**	**130,535**	**133,878**	**134,723**	**137,742**	**138,908**	**140,298**	**142,034**	**143,001**	**144,314**	**146,168**	**147,961**	**149,116**
Gross Energy Generation	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Thermal Generation	MWh		**656,322**	**657,877**	**662,364**	**562,695**	**488,020**	**426,109**	**407,505**	**399,924**	**396,227**	**394,720**	**397,822**	**403,353**	**395,938**	**399,781**	**403,177**	**407,969**	**411,764**	**414,213**	**416,745**	**421,333**	**424,883**	**429,223**	**434,942**	**441,478**	**444,753**	**448,919**	**452,739**	**458,605**	**462,898**
Existing	*MWh*		656,322	657,877	662,364	562,695	488,020	426,109	362,623	353,032	341,093	313,995	305,050	302,104	280,724	282,431	283,874	255,075	238,780	200,713	175,284	176,317	175,738	176,198	176,659	177,469	85,751	-	-	-	-
New	*MWh*		-	-	-	-	-	-	44,882	46,892	55,134	80,725	92,772	101,249	115,214	117,350	119,302	152,895	172,984	213,500	241,461	245,015	249,145	253,025	258,283	264,009	359,003	448,919	452,739	458,605	462,898
Renewable	MWh		**15,074**	**21,739**	**24,612**	**131,305**	**209,810**	**278,573**	**303,639**	**319,665**	**327,111**	**334,549**	**337,355**	**340,675**	**353,737**	**356,121**	**358,288**	**361,646**	**362,397**	**366,614**	**371,414**	**374,136**	**375,041**	**377,163**	**379,149**	**382,602**	**384,247**	**386,284**	**388,969**	**392,568**	**393,392**
DG Solar	*MWh*		8,718	10,394	13,289	18,271	22,058	26,373	31,484	37,406	43,676	50,357	54,262	58,122	61,468	64,748	67,656	70,511	72,654	74,822	76,724	78,682	80,350	82,173	84,247	86,572	88,520	90,761	93,043	95,643	97,817
PV Solar	*MWh*		6,356	11,345	11,322	68,245	124,619	163,732	165,880	165,606	172,148	177,160	176,237	174,765	192,411	191,558	190,806	191,026	190,199	193,361	197,278	197,163	195,603	195,699	195,525	196,088	196,738	196,849	196,766	196,903	195,885
Mastic Wind	*MWh*		-	-	-	-	18,529	41,156	43,348	43,048	40,171	37,732	37,602	38,100	33,551	33,560	33,553	33,644	33,328	32,677	32,118	32,562	33,069	33,190	33,224	33,478	32,910	32,782	33,033	33,514	33,390
Quarry Wind	*MWh*		-	-	-	-	-	3,663	19,269	29,997	27,851	26,202	26,149	26,472	23,530	23,481	23,488	23,564	23,423	23,002	22,593	22,907	23,304	23,375	23,415	23,596	23,332	23,136	23,353	23,610	23,509
Waste to Energy	*MWh*		-	-	-	37,324	37,167	36,338	36,379	36,336	36,052	35,912	35,917	36,010	35,645	35,644	35,651	35,749	35,659	35,625	35,581	35,685	35,595	35,604	35,613	35,722	35,622	35,629	35,643	35,746	35,657
Landfill Gas	*MWh*		-	-	-	7,465	7,437	7,311	7,279	7,272	7,214	7,186	7,188	7,207	7,132	7,131	7,133	7,152	7,134	7,127	7,118	7,138	7,120	7,122	7,124	7,146	7,125	7,127	7,131	7,151	7,134
Total	**MWh**		**671,397**	**679,616**	**686,976**	**694,000**	**697,829**	**704,682**	**711,145**	**719,589**	**723,338**	**729,269**	**735,177**	**744,029**	**749,675**	**755,901**	**761,465**	**769,615**	**774,160**	**780,828**	**788,159**	**795,469**	**799,924**	**806,386**	**814,091**	**824,080**	**829,000**	**835,203**	**841,708**	**851,172**	**856,291**
OPERATIONS																															
Renewable Curtailment (MWh curtailed/Renewable Capability)	*percent*		1.72	2.48	2.81	9.85	18.91	28.68	31.41	33.69	35.67	37.69	38.10	38.50	44.03	44.37	44.65	44.93	45.13	46.63	48.10	48.27	48.42	48.58	48.77	48.98	49.16	49.39	49.62	49.89	50.13
Renewable Curtailed Energy	*MWh*		-	-	-	34	419	16,306	15,156	19,841	28,601	38,724	39,522	40,642	74,783	75,324	75,652	75,685	75,775	84,630	92,661	92,465	91,865	91,133	90,845	90,259	89,174	89,114	88,466	88,313	88,549
Spinning Requirement	*MW*		*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*
Regulation Requirements	*MW*		*0.48*	*0.83*	*0.84*	*4.81*	*10.03*	*14.58*	*15.97*	*16.63*	*16.81*	*16.90*	*16.83*	*16.77*	*17.50*	*17.45*	*17.40*	*17.38*	*17.37*	*17.52*	*17.71*	*17.71*	*17.73*	*17.75*	*17.77*	*17.79*	*17.83*	*17.82*	*17.86*	*17.89*	*17.86*
Reserve Margin	*percent*		*55.65*	*52.31*	*51.02*	*54.76*	*54.90*	*52.50*	*53.05*	*53.21*	*52.26*	*45.49*	*47.09*	*46.19*	*50.37*	*49.47*	*48.59*	*45.14*	*46.03*	*45.19*	*46.06*	*45.24*	*52.48*	*51.56*	*50.65*	*49.76*	*63.66*	*45.00*	*47.41*	*46.58*	*45.73*
Fuel Consumption Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Diesel	MMBtu		5,540,435	5,554,720	5,593,463	4,739,461	4,109,285	3,599,905	3,426,356	3,362,790	3,341,188	3,317,165	3,332,724	3,380,143	3,315,707	3,347,546	3,376,145	3,421,305	3,446,710	3,472,036	3,487,214	3,525,679	3,554,695	3,590,891	3,638,646	3,693,228	3,721,308	3,755,020	3,781,359	3,830,781	3,866,824
Natural Gas	MMBtu		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Portfolio 2 Base		Fiscal Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
COST	**Unit**																														
Total Costs	***$000***		**107,318**	**116,704**	**123,110**	**107,577**	**107,597**	**102,911**	**101,353**	**102,240**	**101,971**	**102,003**	**103,177**	**103,317**	**106,274**	**106,885**	**107,537**	**107,380**	**109,126**	**108,546**	**110,692**	**110,940**	**113,006**	**113,853**	**114,921**	**116,554**	**117,148**	**118,122**	**118,794**	**119,912**	**120,424**
Fuel Costs	*$000*		84,035	92,067	97,380	73,027	68,509	62,895	52,327	50,658	49,523	48,307	48,039	48,326	46,822	47,383	47,974	48,620	48,870	49,486	49,953	50,549	50,795	51,579	52,592	53,312	53,588	54,038	54,697	55,627	56,300
Fixed Costs	*$000*		7,189	7,189	7,189	9,421	9,776	9,555	11,042	11,459	11,356	11,523	11,917	11,742	12,576	12,576	12,576	12,241	12,710	12,291	12,799	12,645	13,228	13,228	13,228	13,364	13,338	13,363	13,363	13,400	13,363
Variable Costs	*$000*		1,779	1,783	1,795	2,075	1,951	1,805	1,585	1,539	1,498	1,483	1,491	1,498	1,465	1,475	1,484	1,495	1,505	1,518	1,531	1,544	1,553	1,565	1,581	1,593	1,594	1,599	1,611	1,628	1,639
CAPEX (New & Existing Units)	*$000*		14,315	15,666	16,746	23,054	27,361	28,657	36,399	38,584	39,594	40,691	41,730	41,752	45,412	45,451	45,503	45,023	46,042	45,251	46,409	46,201	47,429	47,482	47,521	48,285	48,628	49,122	49,122	49,257	49,122
$/KWh Costs			0.16	0.17	0.18	0.16	0.15	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
NPV ($1000), Discount Rate 5.5%	***$1,564,328***																														
ENVIRONMENTAL COMPLIANCE																															
Emissions Amounts (CO2 Tons)	*Tons*		*443,236*	*444,379*	*447,473*	*311,040*	*288,067*	*261,863*	*216,787*	*208,551*	*202,493*	*196,509*	*195,019*	*196,282*	*190,040*	*191,903*	*193,580*	*195,193*	*196,040*	*198,692*	*200,214*	*202,515*	*203,941*	*206,056*	*208,826*	*210,733*	*211,221*	*212,266*	*214,311*	*217,101*	*219,153*
Emission Compliance Target (CO2 Tons) Only for 4-6	*Tons*		*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Renewable Penetration (generation basis)	*percent*		*2.25%*	*3.20%*	*3.58%*	*10.72%*	*17.69%*	*26.16%*	*37.94%*	*40.98%*	*43.20%*	*44.35%*	*44.39%*	*44.76%*	*46.56%*	*46.50%*	*46.44%*	*46.65%*	*46.36%*	*46.21%*	*46.12%*	*46.02%*	*45.87%*	*45.75%*	*45.55%*	*45.72%*	*45.92%*	*46.06%*	*45.96%*	*45.87%*	*45.69%*
Operating Costs Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Fuel	$000		**84,035**	**92,067**	**97,380**	**73,027**	**68,509**	**62,895**	**52,327**	**50,658**	**49,523**	**48,307**	**48,039**	**48,326**	**46,822**	**47,383**	**47,974**	**48,620**	**48,870**	**49,486**	**49,953**	**50,549**	**50,795**	**51,579**	**52,592**	**53,312**	**53,588**	**54,038**	**54,697**	**55,627**	**56,300**
Existing	*$000*		84,035	92,067	97,380	73,027	68,509	62,895	36,753	35,158	34,205	21,040	9,822	10,386	4,545	4,885	5,226	5,838	2,395	3,457	1,298	1,589	505	568	638	678	243	-	-	-	-
New	*$000*		-	-	-	-	-	-	15,574	15,499	15,318	27,267	38,218	37,940	42,276	42,499	42,748	42,782	46,475	46,029	48,655	48,960	50,291	51,011	51,953	52,634	53,345	54,038	54,697	55,627	56,300
Fixed Costs	$000		**7,189**	**7,189**	**7,189**	**9,421**	**9,776**	**9,555**	**11,042**	**11,459**	**11,356**	**11,523**	**11,917**	**11,742**	**12,576**	**12,576**	**12,576**	**12,241**	**12,710**	**12,291**	**12,799**	**12,645**	**13,228**	**13,228**	**13,228**	**13,364**	**13,338**	**13,363**	**13,363**	**13,400**	**13,363**
Existing Units	*$000*		7,189	7,189	7,189	7,209	7,189	6,487	6,207	6,224	5,749	4,919	4,331	4,039	3,710	3,710	3,710	3,171	2,861	2,443	2,147	1,964	1,772	1,772	1,772	1,777	879	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	804	806	804	1,607	2,589	2,596	3,393	3,393	3,393	3,581	4,375	4,375	5,178	5,192	5,982	5,982	5,982	5,998	6,785	7,589	7,589	7,610	7,589
DG Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	*$000*		-	-	-	-	381	862	1,343	1,346	1,343	1,343	1,343	1,346	1,723	1,723	1,723	1,728	1,723	1,723	1,723	1,728	1,723	1,723	1,723	1,829	1,924	2,024	2,024	2,030	2,024
Utility Wind	*$000*		-	-	-	-	-	-	483	871	1,255	1,448	1,448	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544
Waste to Energy	*$000*		-	-	-	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025
Landfill Gas	*$000*		-	-	-	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181
Variable O&M	$000		**1,779**	**1,783**	**1,795**	**2,075**	**1,951**	**1,805**	**1,585**	**1,539**	**1,498**	**1,483**	**1,491**	**1,498**	**1,465**	**1,475**	**1,484**	**1,495**	**1,505**	**1,518**	**1,531**	**1,544**	**1,553**	**1,565**	**1,581**	**1,593**	**1,594**	**1,599**	**1,611**	**1,628**	**1,639**
Existing Units	*$000*		1,779	1,783	1,795	1,679	1,557	1,410	826	785	755	464	217	229	100	108	115	127	52	75	28	34	11	12	14	14	5	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	370	366	359	635	891	885	985	988	991	988	1,073	1,064	1,123	1,129	1,163	1,173	1,188	1,198	1,210	1,221	1,233	1,249	1,260
DG Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Wind	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	*$000*		-	-	-	336	335	335	330	329	327	326	325	326	322	322	322	323	322	322	322	323	322	322	322	323	322	321	321	322	321
Landfill Gas	*$000*		-	-	-	60	60	60	59	59	58	58	58	58	57	57	57	58	57	57	57	58	57	57	57	57	57	57	57	57	57
CAPEX (Ammortized)			**14,315**	**15,666**	**16,746**	**23,054**	**27,361**	**28,657**	**36,399**	**38,584**	**39,594**	**40,691**	**41,730**	**41,752**	**45,412**	**45,451**	**45,503**	**45,023**	**46,042**	**45,251**	**46,409**	**46,201**	**47,429**	**47,482**	**47,521**	**48,285**	**48,628**	**49,122**	**49,122**	**49,257**	**49,122**
CAPEX (Total Spend)			**25,950**	**13,348**	**14,386**	**174,578**	**55,037**	**61,486**	**113,302**	**35,924**	**35,430**	**46,686**	**42,157**	**13,857**	**63,188**	**7,329**	**7,329**	**14,786**	**30,536**	**5,653**	**29,025**	**4,242**	**28,186**	**3,501**	**3,501**	**10,224**	**34,638**	**31,020**	**-**	**-**	**-**
Existing Units	*$000*		12,958	13,348	14,386	14,699	15,629	14,204	12,264	12,264	12,264	10,103	9,441	8,409	7,329	7,329	7,329	7,329	5,653	5,653	4,242	4,242	3,501	3,501	3,501	3,501	3,501	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	25,386	-	-	25,234	32,716	-	25,083	-	-	7,457	24,883	-	24,783	-	24,684	-	-	-	24,487	24,438	-	-	-
DG Solar	*$000*																														
PV Solar	*$000*		12,993	-	-	-	39,408	47,282	45,424	-	-	-	-	-	30,776	-	-	-	-	-	-	-	-	-	-	6,723	6,650	6,582	-	-	-
Utility Wind	*$000*		-	-	-	-	-	-	30,228	23,661	23,167	11,350	-	5,448	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	*$000*		-	-	-	73,820	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Landfill Gas	*$000*		-	-	-	2,659	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conversion Costs	*$000*					83,400																									
TOTAL COST	**$000**		**107,318**	**116,704**	**123,110**	**107,577**	**107,597**	**102,911**	**101,353**	**102,240**	**101,971**	**102,003**	**103,177**	**103,317**	**106,274**	**106,885**	**107,537**	**107,380**	**109,126**	**108,546**	**110,692**	**110,940**	**113,006**	**113,853**	**114,921**	**116,554**	**117,148**	**118,122**	**118,794**	**119,912**	**120,424**
Gross Energy Generation	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Thermal Generation	MWh		**656,322**	**657,877**	**662,364**	**619,600**	**574,416**	**520,338**	**441,312**	**424,684**	**410,822**	**405,806**	**408,836**	**410,992**	**400,604**	**404,432**	**407,866**	**411,385**	**415,230**	**419,977**	**424,671**	**429,382**	**433,028**	**437,469**	**443,311**	**447,301**	**448,318**	**450,518**	**454,852**	**460,741**	**465,064**
Existing	*MWh*		656,322	657,877	662,364	619,600	574,416	520,338	304,829	289,730	278,505	171,322	80,133	84,518	37,072	39,734	42,333	46,719	19,246	27,507	10,367	12,721	3,989	4,473	5,015	5,303	1,882	-	-	-	-
New	*MWh*		-	-	-	-	-	-	136,484	134,955	132,316	234,484	328,703	326,475	363,532	364,699	365,533	364,666	395,984	392,470	414,304	416,661	429,039	432,996	438,296	441,999	446,436	450,518	454,852	460,741	465,064
Renewable	MWh		**15,074**	**21,739**	**24,612**	**74,401**	**123,413**	**184,344**	**269,832**	**294,904**	**312,516**	**323,463**	**326,340**	**333,036**	**349,071**	**351,469**	**353,599**	**358,231**	**358,930**	**360,850**	**363,488**	**366,088**	**366,896**	**368,917**	**370,780**	**376,778**	**380,682**	**384,684**	**386,856**	**390,432**	**391,227**
DG Solar	*MWh*		8,718	10,394	13,289	18,271	22,058	26,373	31,484	37,406	43,676	50,357	54,262	58,122	61,468	64,748	67,656	70,511	72,654	74,822	76,724	78,682	80,350	82,173	84,247	86,572	88,520	90,761	93,043	95,643	97,817
PV Solar	*MWh*		6,356	11,345	11,322	11,332	56,687	113,322	165,899	164,822	162,012	160,071	162,229	161,808	185,201	184,406	183,549	183,891	183,804	183,457	184,119	184,253	183,611	183,571	183,308	187,940	191,689	194,661	194,513	195,020	193,954
Mastic Wind	*MWh*		-	-	-	-	-	-	28,418	44,743	43,708	42,855	41,214	40,978	35,084	35,037	35,019	35,771	35,046	35,099	35,112	35,356	35,251	35,403	35,418	34,836	33,859	33,145	33,166	33,373	33,198
Quarry Wind	*MWh*		-	-	-	-	-	-	-	4,022	19,557	26,767	25,235	28,650	24,413	24,370	24,464	24,971	24,452	24,497	24,547	24,694	24,696	24,776	24,809	24,359	23,735	23,305	23,313	23,447	23,419
Waste to Energy	*MWh*		-	-	-	37,331	37,223	37,207	36,689	36,591	36,299	36,175	36,163	36,230	35,752	35,754	35,757	35,898	35,805	35,806	35,815	35,914	35,818	35,823	35,827	35,886	35,729	35,675	35,681	35,788	35,697
Landfill Gas	*MWh*		-	-	-	7,466	7,445	7,442	7,342	7,321	7,264	7,238	7,237	7,249	7,153	7,154	7,154	7,188	7,169	7,168	7,171	7,189	7,170	7,171	7,172	7,185	7,150	7,138	7,139	7,160	7,142
Total	**MWh**		**671,397**	**679,616**	**686,976**	**694,000**	**697,829**	**704,682**	**711,145**	**719,589**	**723,338**	**729,269**	**735,177**	**744,029**	**749,675**	**755,901**	**761,465**	**769,615**	**774,160**	**780,828**	**788,159**	**795,469**	**799,924**	**806,386**	**814,091**	**824,080**	**829,000**	**835,203**	**841,708**	**851,172**	**856,291**
OPERATIONS																54%															
Renewable Curtailment	*percent*		1.72	2.48	2.81	3.37	8.99	15.96	26.58	29.91	32.77	34.59	35.00	35.95	41.49	41.83	42.12	42.40	42.61	42.81	42.99	43.17	43.33	43.50	43.70	45.21	46.70	48.21	48.43	48.69	48.94
Renewable Curtailed Energy	*MWh*		-	-	-	-	27	106	7,007	11,703	18,113	22,959	23,700	26,192	57,298	57,863	58,257	57,107	57,292	57,163	56,063	56,067	55,633	55,110	55,017	63,245	71,253	80,439	80,238	80,014	80,295
Spinning Requirement	*MW*		*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*
Regulation Requirements	*MW*		*0.48*	*0.83*	*0.84*	*0.86*	*4.03*	*8.00*	*13.63*	*14.91*	*15.78*	*16.11*	*16.05*	*16.22*	*17.17*	*17.11*	*17.07*	*17.13*	*17.11*	*17.10*	*17.14*	*17.14*	*17.14*	*17.16*	*17.17*	*17.38*	*17.57*	*17.71*	*17.71*	*17.74*	*17.71*
Reserve Margin	*percent*		*55.65*	*52.31*	*51.02*	*54.76*	*53.76*	*49.09*	*50.03*	*50.59*	*51.14*	*45.12*	*46.72*	*46.19*	*50.37*	*49.47*	*48.59*	*48.60*	*49.47*	*48.61*	*49.46*	*48.62*	*55.84*	*54.90*	*53.97*	*53.06*	*66.94*	*48.27*	*47.41*	*46.58*	*45.73*
Fuel Consumption Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Diesel	MMBtu		5,540,456	5,554,734	5,593,414	8,546	7,205	12,623	182	219	4,701	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	MMBtu		-	-	-	5,216,065	4,831,769	4,384,085	3,643,240	3,504,771	3,396,930	3,302,124	3,277,635	3,298,852	3,193,951	3,225,266	3,253,449	3,280,548	3,294,783	3,339,365	3,364,940	3,403,617	3,427,575	3,463,128	3,509,684	3,541,729	3,549,925	3,567,490	3,601,872	3,648,751	3,683,252

Portfolio 3 Base		Fiscal Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
COST	**Unit**																														
Total Costs	***$000***		**107,318**	**116,704**	**123,111**	**107,578**	**107,214**	**106,433**	**103,624**	**101,679**	**99,120**	**98,667**	**100,076**	**100,278**	**103,215**	**103,839**	**104,733**	**104,198**	**105,869**	**105,296**	**108,622**	**108,839**	**108,544**	**109,350**	**110,368**	**111,566**	**111,722**	**112,268**	**113,493**	**115,783**	**116,292**
Fuel Costs	*$000*		84,035	92,066	97,381	73,028	66,217	62,033	54,845	48,585	44,308	41,468	39,739	39,515	38,475	39,048	39,131	40,002	40,191	40,813	39,771	40,314	40,567	41,308	42,271	43,215	43,735	44,418	45,020	45,903	46,587
Fixed Costs	*$000*		7,189	7,189	7,189	9,421	10,065	9,944	10,335	10,845	10,738	11,098	11,782	11,703	13,557	13,557	13,657	13,146	13,612	13,194	14,082	13,932	13,308	13,308	13,308	13,344	13,218	13,142	13,321	14,564	14,524
Variable Costs	*$000*		1,779	1,783	1,795	2,075	1,900	1,787	1,618	1,473	1,363	1,314	1,291	1,286	1,269	1,280	1,277	1,291	1,301	1,315	1,291	1,304	1,313	1,325	1,341	1,360	1,368	1,379	1,392	1,408	1,420
CAPEX (New & Existing Units)	*$000*		14,315	15,666	16,746	23,054	29,032	32,669	36,826	40,776	42,711	44,787	47,264	47,773	49,915	49,954	50,668	49,759	50,764	49,974	53,478	53,290	53,357	53,409	53,448	53,647	53,402	53,329	53,761	53,908	53,761
$/kWh Costs			0.16	0.17	0.18	0.16	0.15	0.15	0.15	0.14	0.14	0.13	0.14	0.13	0.14	0.14	0.14	0.13	0.14	0.13	0.14	0.14	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.14
NPV ($1000), Discount Rate 5.5%	***$1,539,694***																														
ENVIRONMENTAL COMPLIANCE																															
Emissions Amounts (CO2 Tons)	*Tons*		*443,237*	*444,378*	*447,477*	*311,041*	*278,531*	*258,308*	*227,284*	*199,982*	*181,108*	*168,682*	*161,348*	*160,520*	*156,203*	*158,177*	*157,927*	*160,613*	*161,246*	*163,891*	*159,429*	*161,528*	*162,900*	*165,050*	*167,871*	*170,838*	*172,405*	*174,497*	*176,413*	*179,172*	*181,364*
Emission Compliance Target (CO2 Tons) Only for 4-6	*Tons*		*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Renewable Penetration (generation basis)	*percent*		*2.25%*	*3.20%*	*3.58%*	*10.72%*	*20.38%*	*27.19%*	*36.63%*	*44.88%*	*50.60%*	*53.37%*	*54.83%*	*55.60%*	*56.62%*	*56.46%*	*56.86%*	*56.69%*	*56.40%*	*56.17%*	*57.55%*	*57.38%*	*57.15%*	*56.94%*	*56.63%*	*56.38%*	*56.23%*	*56.05%*	*55.86%*	*55.68%*	*55.40%*
Operating Costs Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Fuel	$000		**84,035**	**92,066**	**97,381**	**73,028**	**66,217**	**62,033**	**54,845**	**48,585**	**44,308**	**41,468**	**39,739**	**39,515**	**38,475**	**39,048**	**39,131**	**40,002**	**40,191**	**40,813**	**39,771**	**40,314**	**40,567**	**41,308**	**42,271**	**43,215**	**43,735**	**44,418**	**45,020**	**45,903**	**46,587**
Existing	*$000*		84,035	92,066	97,381	73,028	66,217	62,033	54,845	48,585	44,308	30,425	15,976	15,846	6,933	7,500	7,636	8,595	3,363	4,013	1,227	1,572	265	363	500	508	65	-	-	-	-
New	*$000*		-	-	-	-	-	-	-	-	-	11,044	23,763	23,670	31,542	31,548	31,495	31,408	36,827	36,800	38,544	38,742	40,302	40,944	41,771	42,708	43,670	44,418	45,020	45,903	46,587
Fixed Costs	$000		**7,189**	**7,189**	**7,189**	**9,421**	**10,065**	**9,944**	**10,335**	**10,845**	**10,738**	**11,098**	**11,782**	**11,703**	**13,557**	**13,557**	**13,657**	**13,146**	**13,612**	**13,194**	**14,082**	**13,932**	**13,308**	**13,308**	**13,308**	**13,344**	**13,218**	**13,142**	**13,321**	**14,564**	**14,524**
Existing Units	*$000*		7,189	7,189	7,189	7,209	7,189	6,487	6,207	6,224	5,749	4,919	4,331	4,039	3,710	3,710	3,710	3,171	2,861	2,443	2,147	1,964	1,772	1,772	1,772	1,777	879	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	-	-	-	804	1,786	1,790	2,589	2,589	2,589	2,596	3,393	3,393	4,196	4,208	5,000	5,000	5,000	5,013	5,803	6,607	6,785	6,804	6,785
DG Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	*$000*		-	-	-	-	381	761	1,142	1,627	2,004	2,004	2,004	2,009	2,104	2,104	2,204	2,210	2,204	2,204	2,585	2,592	2,585	2,585	2,585	2,592	2,585	2,585	2,585	2,592	2,585
Utility Wind	*$000*		-	-	-	-	290	290	579	581	579	965	1,255	1,452	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544	1,544	1,544	1,548	1,544
Waste to Energy	*$000*		-	-	-	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025
Landfill Gas	*$000*		-	-	-	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181
Battery	*$000*		-	-	-	-	-	201	201	201	201	201	201	201	1,404	1,404	1,404	1,408	1,404	1,404	1,404	1,408	201	201	201	201	201	201	201	1,408	1,404
Variable O&M	$000		**1,779**	**1,783**	**1,795**	**2,075**	**1,900**	**1,787**	**1,618**	**1,473**	**1,363**	**1,314**	**1,291**	**1,286**	**1,269**	**1,280**	**1,277**	**1,291**	**1,301**	**1,315**	**1,291**	**1,304**	**1,313**	**1,325**	**1,341**	**1,360**	**1,368**	**1,379**	**1,392**	**1,408**	**1,420**
Existing Units	*$000*		1,779	1,783	1,795	1,679	1,506	1,392	1,224	1,078	973	670	352	349	152	164	166	185	73	85	26	34	6	8	11	11	1	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	-	-	-	256	553	551	734	733	729	723	847	848	886	890	929	939	952	969	988	1,001	1,013	1,028	1,041
DG Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Wind	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	*$000*		-	-	-	336	335	335	335	335	331	329	328	328	325	325	324	325	324	324	321	322	321	321	322	323	322	322	322	323	322
Landfill Gas	*$000*		-	-	-	60	60	60	60	60	59	59	58	58	58	58	58	58	58	58	57	57	57	57	57	57	57	57	57	57	57
Battery	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPEX (Ammortized)			**14,315**	**15,666**	**16,746**	**23,054**	**29,032**	**32,669**	**36,826**	**40,776**	**42,711**	**44,787**	**47,264**	**47,773**	**49,915**	**49,954**	**50,668**	**49,759**	**50,764**	**49,974**	**53,478**	**53,290**	**53,357**	**53,409**	**53,448**	**53,647**	**53,402**	**53,329**	**53,761**	**53,908**	**53,761**
CAPEX (Total Spend)			**25,950**	**13,348**	**14,386**	**174,578**	**74,410**	**81,672**	**66,432**	**56,316**	**46,230**	**58,036**	**58,838**	**19,305**	**45,771**	**7,329**	**15,007**	**7,329**	**30,536**	**5,653**	**56,235**	**4,242**	**28,186**	**3,501**	**3,501**	**3,501**	**27,989**	**24,438**	**7,295**	**-**	**-**
Existing Units	*$000*		12,958	13,348	14,386	14,699	15,629	14,204	12,264	12,264	12,264	10,103	9,441	8,409	7,329	7,329	7,329	7,329	5,653	5,653	4,242	4,242	3,501	3,501	3,501	3,501	3,501	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	-	-	-	25,234	32,716	-	25,083	-	-	-	24,883	-	24,783	-	24,684	-	-	-	24,487	24,438	7,295	-	-
DG Solar	*$000*																														
PV Solar	*$000*		12,993	-	-	-	39,408	37,506	36,032	44,052	33,966	-	-	-	8,022	-	7,678	-	-	-	27,210	-	-	-	-	-	-	-	-	-	-
Utility Wind	*$000*		-	-	-	-	19,373	-	18,137	-	-	22,700	16,681	10,896	5,337	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	*$000*		-	-	-	73,820	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Landfill Gas	*$000*		-	-	-	2,659	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery	*$000*		-	-	-	-	-	29,962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conversion Costs	*$000*					83,400																									
TOTAL COST	**$000**		**107,318**	**116,704**	**123,111**	**107,578**	**107,214**	**106,433**	**103,624**	**101,679**	**99,120**	**98,667**	**100,076**	**100,278**	**103,215**	**103,839**	**104,733**	**104,198**	**105,869**	**105,296**	**108,622**	**108,839**	**108,544**	**109,350**	**110,368**	**111,566**	**111,722**	**112,268**	**113,493**	**115,783**	**116,292**
Gross Energy Generation	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Thermal Generation	MWh		**656,322**	**657,877**	**662,364**	**619,600**	**555,620**	**513,812**	**451,592**	**397,777**	**359,112**	**341,851**	**333,861**	**332,148**	**327,065**	**330,983**	**330,437**	**335,260**	**339,448**	**344,215**	**336,623**	**341,056**	**344,776**	**349,307**	**355,123**	**361,540**	**364,912**	**369,199**	**373,636**	**379,383**	**384,041**
Existing	*MWh*		656,322	657,877	662,364	619,600	555,620	513,812	451,592	397,777	359,112	247,278	129,864	128,753	56,033	60,560	61,391	68,314	26,775	31,435	9,524	12,483	2,120	2,913	3,994	4,029	507	-	-	-	-
New	*MWh*		-	-	-	-	-	-	-	-	-	94,573	203,997	203,396	271,032	270,423	269,046	266,946	312,673	312,780	327,100	328,574	342,656	346,394	351,129	357,510	364,405	369,199	373,636	379,383	384,041
Renewable	MWh		**15,074**	**21,739**	**24,612**	**74,401**	**142,209**	**191,858**	**261,034**	**323,910**	**367,859**	**391,201**	**405,190**	**415,911**	**426,870**	**429,191**	**435,481**	**438,833**	**439,179**	**441,050**	**456,304**	**459,203**	**459,801**	**461,851**	**463,746**	**467,294**	**468,842**	**470,763**	**472,816**	**476,554**	**476,985**
DG Solar	*MWh*		8,718	10,394	13,289	18,271	22,058	26,373	31,484	37,406	43,676	50,357	54,262	58,122	61,468	64,748	67,656	70,511	72,654	74,822	76,724	78,682	80,350	82,173	84,247	86,572	88,520	90,761	93,043	95,643	97,817
PV Solar	*MWh*		6,356	11,345	11,322	11,332	56,714	102,072	147,338	204,255	244,846	242,565	240,976	239,895	247,041	246,541	252,892	252,922	252,308	251,594	273,838	274,568	274,209	274,192	273,781	274,554	273,397	273,550	273,196	273,927	272,662
Mastic Wind	*MWh*		-	-	-	-	18,767	18,771	37,541	37,522	35,251	45,954	45,522	45,392	43,666	43,464	41,833	42,019	41,342	41,566	36,586	36,679	36,231	36,378	36,507	36,667	37,282	37,100	37,174	37,354	37,133
Quarry Wind	*MWh*		-	-	-	-	-	-	-	-	-	8,460	20,718	28,780	31,326	31,082	29,950	30,074	29,677	29,863	26,320	26,313	26,154	26,240	26,339	26,490	26,750	26,454	26,489	26,591	26,431
Waste to Energy	*MWh*		-	-	-	37,331	37,225	37,199	37,225	37,271	36,735	36,550	36,424	36,433	36,138	36,126	35,979	36,085	35,995	36,009	35,694	35,798	35,711	35,721	35,725	35,839	35,741	35,746	35,759	35,863	35,782
Landfill Gas	*MWh*		-	-	-	7,466	7,445	7,444	7,446	7,457	7,351	7,314	7,288	7,290	7,232	7,230	7,202	7,222	7,204	7,207	7,142	7,163	7,145	7,147	7,148	7,171	7,151	7,152	7,155	7,177	7,159
Total	**MWh**		**671,397**	**679,616**	**686,976**	**694,000**	**697,829**	**705,670**	**712,625**	**721,687**	**726,971**	**733,053**	**739,052**	**748,059**	**753,935**	**760,174**	**765,919**	**774,093**	**778,627**	**785,266**	**792,927**	**800,260**	**804,577**	**811,158**	**818,870**	**828,834**	**833,754**	**839,962**	**846,452**	**855,937**	**861,026**
OPERATIONS																0.43540444															
Renewable Curtailment	*percent*		1.72	2.48	2.81	3.37	11.14	16.81	24.70	31.83	37.70	40.93	42.96	44.44	46.62	46.94	48.52	48.80	48.99	49.19	54.54	54.70	54.84	54.99	55.17	55.37	55.54	55.75	55.95	56.20	56.43
Renewable Curtailed Energy	*MWh*		-	-	-	-	4	0	1	398	6,444	11,211	14,849	18,153	24,899	25,389	32,766	33,006	33,159	33,041	64,291	64,069	63,425	62,719	62,447	61,923	60,617	60,476	60,242	59,961	60,270
Spinning Requirement	*MW*		*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*
Regulation Requirements	*MW*		*0.48*	*0.83*	*0.84*	*0.86*	*5.32*	*8.50*	*12.96*	*16.88*	*19.62*	*20.81*	*21.51*	*21.96*	*22.54*	*22.48*	*22.74*	*22.70*	*22.68*	*22.66*	*23.61*	*23.60*	*23.61*	*23.63*	*23.65*	*23.66*	*23.70*	*23.68*	*23.68*	*23.71*	*23.67*
Reserve Margin	*percent*		*55.65*	*52.31*	*51.02*	*54.76*	*54.90*	*68.62*	*52.24*	*51.28*	*50.34*	*45.06*	*47.77*	*47.60*	*52.13*	*51.22*	*50.33*	*46.87*	*47.75*	*46.90*	*47.76*	*46.93*	*54.16*	*53.23*	*52.31*	*51.41*	*65.30*	*46.63*	*49.03*	*48.19*	*47.34*
Fuel Consumption Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Diesel	MMBtu		5,540,465	5,554,725	5,593,456	8,546	6,013	1,660	1,640	1,254	5,628	780	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	MMBtu		-	-	-	5,216,090	4,673,104	4,339,080	3,817,687	3,359,349	3,036,262	2,833,942	2,711,737	2,697,815	2,625,261	2,658,444	2,654,234	2,699,387	2,710,016	2,754,463	2,679,487	2,714,748	2,737,810	2,773,956	2,821,365	2,871,224	2,897,562	2,932,722	2,964,929	3,011,286	3,048,138

Portfolio 4 Base		Fiscal Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
COST	**Unit**																														
Total Costs	**$000**		**107,339**	**116,709**	**123,116**	**123,481**	**120,257**	**116,580**	**113,183**	**113,892**	**112,756**	**110,814**	**109,862**	**109,890**	**187,761**	**113,641**	**115,930**	**120,817**	**122,166**	**124,721**	**124,495**	**125,127**	**123,847**	**125,527**	**124,261**	**125,779**	**127,684**	**126,032**	**127,095**	**130,097**	**130,707**
Fuel Costs	*$000*		84,056	92,072	97,386	83,960	73,346	61,423	54,554	47,114	44,250	40,505	41,258	35,889	36,714	36,147	36,871	37,655	38,572	39,602	36,044	36,948	37,839	38,184	39,351	40,046	40,863	41,820	42,872	44,122	44,317
Fixed Costs	*$000*		7,189	7,189	7,189	9,903	10,647	11,159	11,360	12,125	12,014	11,535	10,948	11,306	12,461	12,712	14,216	15,318	16,479	16,864	18,453	18,315	18,078	18,353	16,849	16,992	16,334	15,455	15,455	17,006	17,059
Variable Costs	*$000*		1,779	1,783	1,795	1,921	1,717	1,489	1,357	1,221	1,159	1,093	1,102	1,005	1,014	1,003	1,012	1,024	1,035	1,048	978	991	1,002	1,006	1,021	1,030	1,039	1,050	1,062	1,077	1,074
CAPEX (New & Existing Units)	*$000*		14,315	15,666	16,746	27,697	34,548	42,509	45,911	53,432	55,333	57,681	56,555	61,689	137,571	63,779	63,831	66,819	66,080	67,206	69,020	68,873	66,928	67,983	67,040	67,711	69,448	67,707	67,707	67,893	68,257
$/KWh Costs			0.16	0.17	0.18	0.18	0.17	0.17	0.16	0.16	0.15	0.15	0.15	0.14	0.25	0.15	0.15	0.15	0.15	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
NPV ($1000), Discount Rate 5.5%	***$1,729,592***																														
ENVIRONMENTAL COMPLIANCE																															
Emissions Amounts (CO2 Tons)	*Tons*		*443,350*	*444,405*	*447,500*	*379,161*	*328,777*	*273,360*	*241,322*	*207,078*	*193,397*	*175,848*	*177,993*	*153,799*	*156,344*	*152,931*	*155,022*	*157,310*	*160,093*	*163,331*	*147,714*	*150,489*	*153,192*	*153,733*	*157,589*	*159,507*	*161,569*	*164,172*	*167,078*	*170,682*	*170,233*
Emission Compliance Target (CO2 Tons) Only for 4-6	*Tons*		*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*
Renewable Penetration (generation basis)	*percent*		*2.25%*	*3.20%*	*3.58%*	*18.92%*	*30.06%*	*42.80%*	*49.98%*	*57.74%*	*60.71%*	*64.70%*	*64.55%*	*69.83%*	*69.57%*	*70.64%*	*70.44%*	*70.22%*	*69.85%*	*69.49%*	*72.74%*	*72.47%*	*72.12%*	*72.16%*	*71.73%*	*71.73%*	*71.45%*	*71.20%*	*70.92%*	*70.61%*	*70.86%*
Opeating Costs Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Fuel	$000		**84,056**	**92,072**	**97,386**	**83,960**	**73,346**	**61,423**	**54,554**	**47,114**	**44,250**	**40,505**	**41,258**	**35,889**	**36,714**	**36,147**	**36,871**	**37,655**	**38,572**	**39,602**	**36,044**	**36,948**	**37,839**	**38,184**	**39,351**	**40,046**	**40,863**	**41,820**	**42,872**	**44,122**	**44,317**
Existing	$000		84,056	92,072	97,386	83,960	73,346	61,423	54,554	47,114	44,250	40,505	41,258	35,889	36,714	36,147	36,871	31,307	29,138	21,733	23,008	22,314	21,950	19,317	18,485	18,874	2,151	-	-	-	-
New	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,348	9,434	17,869	13,036	14,633	15,890	18,868	20,866	21,172	38,712	41,820	42,872	44,122	44,317
Fixed Costs	$000		**7,189**	**7,189**	**7,189**	**9,903**	**10,647**	**11,159**	**11,360**	**12,125**	**12,014**	**11,535**	**10,948**	**11,306**	**12,461**	**12,712**	**14,216**	**15,318**	**16,479**	**16,864**	**18,453**	**18,315**	**18,078**	**18,353**	**16,849**	**16,992**	**16,334**	**15,455**	**15,455**	**17,006**	**17,059**
Existing Units	$000		7,189	7,189	7,189	7,209	7,189	6,487	6,207	6,224	5,749	4,919	4,331	4,039	3,710	3,710	3,710	3,171	2,861	2,443	2,147	1,964	1,772	1,772	1,772	1,777	879	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,611	1,607	2,411	2,411	2,417	2,411	2,589	2,589	2,596	4,375	4,375	4,375	4,387	4,375
DG Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	$000		-	-	-	482	962	1,443	1,924	2,412	2,786	2,886	2,886	3,276	3,267	3,267	3,267	3,276	3,267	3,267	3,647	3,657	3,647	3,647	3,647	3,657	3,647	3,647	3,647	3,657	3,748
Utility Wind	$000		-	-	-	-	290	772	772	774	772	772	772	774	772	772	772	774	772	772	772	774	772	869	869	968	965	965	965	968	965
Waste to Energy	$000		-	-	-	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025
Landfill Gas	$000		-	-	-	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181
Battery	$000		-	-	-	-	-	251	251	503	501	752	752	1,005	2,507	2,758	4,262	4,273	5,766	5,766	7,270	7,290	7,270	7,270	5,766	5,782	4,262	4,262	4,262	5,782	5,766
Variable O&M	$000		**1,779**	**1,783**	**1,795**	**1,921**	**1,717**	**1,489**	**1,357**	**1,221**	**1,159**	**1,093**	**1,102**	**1,005**	**1,014**	**1,003**	**1,012**	**1,024**	**1,035**	**1,048**	**978**	**991**	**1,002**	**1,006**	**1,021**	**1,030**	**1,039**	**1,050**	**1,062**	**1,077**	**1,074**
Existing Units	$000		1,779	1,783	1,795	1,525	1,323	1,095	968	832	779	708	717	620	631	615	623	527	487	361	380	366	358	313	298	303	35	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107	159	298	216	241	261	309	340	343	621	666	678	692	691
DG Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Wind	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	$000		-	-	-	336	334	335	331	330	323	327	327	327	326	330	330	331	330	330	324	326	325	325	325	326	326	326	326	327	325
Landfill Gas	$000		-	-	-	60	59	60	59	59	57	58	58	58	58	59	59	59	59	59	58	58	58	58	58	58	58	58	58	58	58
Battery	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPEX (Ammortized)			**14,315**	**15,666**	**16,746**	**27,697**	**34,548**	**42,509**	**45,911**	**53,432**	**55,333**	**57,681**	**56,555**	**61,689**	**137,571**	**63,779**	**63,831**	**66,819**	**66,080**	**67,206**	**69,020**	**68,873**	**66,928**	**67,983**	**67,040**	**67,711**	**69,448**	**67,707**	**67,707**	**67,893**	**68,257**
CAPEX (Total Spend)			**25,950**	**13,348**	**14,386**	**144,864**	**84,681**	**130,068**	**57,688**	**89,585**	**46,230**	**48,910**	**9,441**	**67,869**	**83,971**	**33,774**	**7,329**	**57,194**	**5,653**	**30,486**	**31,452**	**4,242**	**3,501**	**15,909**	**3,501**	**8,532**	**59,800**	**-**	**-**	**-**	**6,378**
Existing Units	$000		12,958	13,348	14,386	14,699	15,629	14,204	12,264	12,264	12,264	10,103	9,441	8,409	7,329	7,329	7,329	7,329	5,653	5,653	4,242	4,242	3,501	3,501	3,501	3,501	3,501	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	-	-	-	-	-	-	76,642	-	-	49,865	-	24,833	-	-	-	7,368	-	-	56,299	-	-	-	-
DG Solar	$000																														
PV Solar	$000		12,993	-	-	53,686	49,680	47,282	45,424	44,052	33,966	8,624	-	31,498	-	-	-	-	-	-	27,210	-	-	-	-	-	-	-	-	-	6,378
Utility Wind	$000		-	-	-	-	19,373	31,129	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,039	-	5,031	-	-	-	-	-
Waste to Energy	$000		-	-	-	73,820	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Landfill Gas	$000		-	-	-	2,659	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery	$000		-	-	-	-	-	37,453	-	33,269	-	30,184	-	27,962	-	26,445	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conversion Costs	$000																														
TOTAL COST	**$000**		**107,339**	**116,709**	**123,116**	**123,481**	**120,257**	**116,580**	**113,183**	**113,892**	**112,756**	**110,814**	**109,862**	**109,890**	**187,761**	**113,641**	**115,930**	**120,817**	**122,166**	**124,721**	**124,495**	**125,127**	**123,847**	**125,527**	**124,261**	**125,779**	**127,684**	**126,032**	**127,095**	**130,097**	**130,707**
Gross Energy Generation	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Thermal Generation	MWh		**656,322**	**657,877**	**662,364**	**562,698**	**488,048**	**403,968**	**357,124**	**306,890**	**287,336**	**261,303**	**264,508**	**228,951**	**232,692**	**226,753**	**229,970**	**234,092**	**238,331**	**243,247**	**219,964**	**224,159**	**228,275**	**229,710**	**235,436**	**238,292**	**242,007**	**245,901**	**250,182**	**255,534**	**254,981**
Existing	*MWh*		656,322	657,877	662,364	562,698	488,048	403,968	357,124	306,890	287,336	261,303	264,508	228,951	232,692	226,753	229,970	194,466	179,772	133,132	140,313	135,060	132,069	115,616	110,003	111,725	12,872	-	-	-	-
New	*MWh*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39,626	58,559	110,115	79,651	89,099	96,207	114,094	125,432	126,567	229,135	245,901	250,182	255,534	254,981
Renewable	MWh		**15,074**	**21,739**	**24,612**	**131,302**	**209,782**	**302,256**	**356,844**	**419,301**	**443,910**	**478,934**	**481,690**	**529,881**	**531,873**	**545,630**	**548,032**	**552,058**	**552,256**	**554,011**	**587,020**	**590,159**	**590,395**	**595,429**	**597,367**	**604,611**	**605,699**	**607,887**	**610,014**	**614,059**	**619,986**
DG Solar	*MWh*		8,718	10,394	13,289	18,271	22,058	26,373	31,484	37,406	43,676	50,357	54,262	58,122	61,468	64,748	67,656	70,511	72,654	74,822	76,724	78,682	80,350	82,173	84,247	86,572	88,520	90,761	93,043	95,643	97,817
PV Solar	*MWh*		6,356	11,345	11,322	68,245	124,613	181,305	233,886	289,640	314,773	338,733	337,782	362,157	381,026	388,783	388,158	388,952	387,167	386,671	421,486	422,397	421,125	420,117	419,630	420,273	418,892	418,814	418,708	419,453	425,418
Mastic Wind	*MWh*		-	-	-	-	18,513	49,946	47,390	48,184	42,415	46,277	46,096	46,024	45,924	48,149	48,240	48,439	48,375	48,459	45,542	45,650	45,565	45,530	45,826	45,770	46,246	46,271	46,206	46,721	45,068
Quarry Wind	*MWh*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,243	4,278	8,502	8,631	8,622	8,619	8,689	8,370
Waste to Energy	*MWh*		-	-	-	37,322	37,162	37,193	36,735	36,719	35,867	36,300	36,288	36,310	36,204	36,613	36,642	36,788	36,711	36,705	36,047	36,184	36,124	36,134	36,150	36,237	36,170	36,177	36,195	36,292	36,089
Landfill Gas	*MWh*		-	-	-	7,464	7,436	7,439	7,350	7,352	7,180	7,266	7,263	7,269	7,252	7,338	7,338	7,367	7,349	7,354	7,220	7,246	7,232	7,233	7,236	7,256	7,241	7,243	7,243	7,263	7,224
Total	**MWh**		**671,397**	**679,616**	**686,976**	**694,000**	**697,829**	**706,225**	**713,967**	**726,191**	**731,246**	**740,236**	**746,198**	**758,833**	**764,565**	**772,383**	**778,002**	**786,149**	**790,587**	**797,258**	**806,985**	**814,318**	**818,670**	**825,139**	**832,803**	**842,903**	**847,706**	**853,788**	**860,196**	**869,593**	**874,967**
OPERATIONS																59%															
Renewable Curtailment	*percent*		1.72	2.48	2.81	9.85	18.91	29.43	36.46	43.58	49.43	51.42	51.80	57.36	57.67	57.96	58.22	58.47	58.64	58.81	64.14	64.28	64.40	65.07	65.23	65.95	66.10	66.29	66.49	66.72	68.24
Renewable Curtailed Energy	*MWh*		-	-	-	34	442	189	6,639	7,569	32,104	15,056	15,618	17,459	16,729	6,087	5,936	5,640	5,480	5,220	18,155	17,844	17,068	17,957	17,417	18,124	16,753	16,211	15,860	15,516	21,152
Spinning Requirement	*MW*		*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*
Regulation Requirements	*MW*		*0.48*	*0.83*	*0.84*	*4.81*	*10.03*	*16.16*	*19.66*	*23.53*	*24.97*	*26.93*	*26.86*	*29.92*	*29.87*	*30.56*	*30.53*	*30.52*	*30.52*	*30.49*	*32.69*	*32.67*	*32.68*	*32.91*	*32.94*	*33.17*	*33.19*	*33.20*	*33.20*	*33.23*	*33.62*
Reserve Margin	*percent*		*55.65*	*52.31*	*51.02*	*54.76*	*54.90*	*75.11*	*57.56*	*79.27*	*78.16*	*77.50*	*59.30*	*80.47*	*68.59*	*89.46*	*88.34*	*115.81*	*100.81*	*115.05*	*100.22*	*99.09*	*90.89*	*93.43*	*92.27*	*91.47*	*123.18*	*89.49*	*88.40*	*87.34*	*86.26*
Fuel Consumption Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Diesel	MMBtu		5,541,870	5,555,066	5,593,750	4,739,515	4,109,708	3,417,005	3,016,519	2,588,474	2,417,467	2,198,106	2,224,909	1,922,493	1,954,305	1,911,642	1,937,770	1,966,374	2,001,157	2,041,642	1,846,429	1,881,117	1,914,904	1,921,665	1,969,860	1,993,835	2,019,614	2,052,153	2,088,479	2,133,528	2,127,914
Natural Gas	MMBtu		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Portfolio 5 Base		Fiscal Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
COST	**Unit**																														
Total Costs	*$000*		**107,336**	**116,710**	**123,113**	**107,577**	**107,189**	**105,900**	**102,919**	**101,595**	**100,652**	**100,234**	**101,021**	**100,949**	**104,209**	**104,890**	**105,492**	**104,874**	**104,385**	**103,780**	**103,836**	**104,047**	**106,024**	**106,842**	**107,852**	**182,593**	**111,643**	**109,915**	**110,582**	**112,852**	**113,473**
Fuel Costs	*$000*		84,052	92,072	97,384	73,027	67,146	61,540	54,504	47,940	44,947	44,434	43,840	44,467	41,538	34,460	35,000	35,774	36,319	36,910	36,732	37,274	37,387	38,141	39,095	40,071	40,519	40,359	41,014	41,873	42,153
Fixed Costs	*$000*		7,189	7,189	7,189	9,421	9,876	9,856	10,153	10,853	11,026	11,000	11,312	11,039	13,175	13,956	13,956	13,446	13,108	12,689	12,587	12,432	14,219	14,219	14,219	14,258	14,932	14,247	14,247	15,492	15,546
Variable Costs	*$000*		1,779	1,783	1,795	2,075	1,920	1,776	1,611	1,454	1,382	1,384	1,381	1,396	1,336	1,181	1,190	1,204	1,215	1,228	1,222	1,235	1,245	1,258	1,274	1,293	1,302	1,295	1,307	1,323	1,326
CAPEX (New & Existing Units)	*$000*		14,315	15,666	16,746	23,054	28,247	32,727	36,651	41,347	43,298	43,415	44,488	44,046	48,161	55,293	55,345	54,449	53,743	52,953	53,295	53,106	53,173	53,225	53,264	126,972	54,890	54,015	54,015	54,163	54,447
$/KWh Costs			0.16	0.17	0.18	0.16	0.15	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.22	0.13	0.13	0.13	0.13	0.13
NPV ($1000), Discount Rate 5.5%	***$1,553,365***																														
ENVIRONMENTAL COMPLIANCE																															
Emissions Amounts (CO2 Tons)	*Tons*		*443,328*	*444,408*	*447,488*	*311,040*	*282,336*	*256,176*	*225,712*	*197,284*	*183,766*	*180,721*	*177,955*	*180,582*	*168,587*	*139,564*	*141,227*	*143,613*	*145,693*	*148,191*	*147,231*	*149,327*	*150,119*	*152,383*	*155,242*	*158,394*	*159,709*	*158,547*	*160,710*	*163,437*	*164,102*
Emission Compliance Target (CO2 Tons) Only for 4-6	*Tons*		*441,463*	*455,903*	*464,271*	*471,235*	*440,709*	*410,183*	*379,657*	*349,131*	*318,605*	*288,868*	*259,132*	*229,395*	*199,659*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*
Renewable Penetration (generation basis)	*percent*		*2.25%*	*3.20%*	*3.58%*	*10.72%*	*19.31%*	*27.75%*	*37.01%*	*45.66%*	*49.48%*	*49.74%*	*50.27%*	*50.15%*	*53.19%*	*61.55%*	*61.38%*	*61.17%*	*60.85%*	*60.57%*	*61.20%*	*61.01%*	*60.72%*	*60.46%*	*60.10%*	*59.78%*	*59.60%*	*60.19%*	*59.96%*	*59.74%*	*59.80%*
Operating Costs Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Fuel	$000		**84,052**	**92,072**	**97,384**	**73,027**	**67,146**	**61,540**	**54,504**	**47,940**	**44,947**	**44,434**	**43,840**	**44,467**	**41,538**	**34,460**	**35,000**	**35,774**	**36,319**	**36,910**	**36,732**	**37,274**	**37,387**	**38,141**	**39,095**	**40,071**	**40,519**	**40,359**	**41,014**	**41,873**	**42,153**
Existing	*$000*		84,052	92,072	97,384	73,027	67,146	61,540	54,504	47,940	42,641	30,345	19,621	19,845	9,137	3,820	4,077	4,512	5,151	5,753	6,085	6,565	1,360	1,583	1,807	2,041	52	-	-	-	-
New	*$000*		-	-	-	-	-	-	-	-	2,306	14,090	24,220	24,622	32,401	30,640	30,923	31,262	31,168	31,156	30,647	30,709	36,027	36,558	37,288	38,030	40,467	40,359	41,014	41,873	42,153
Fixed Costs	$000		**7,189**	**7,189**	**7,189**	**9,421**	**9,876**	**9,856**	**10,153**	**10,853**	**11,026**	**11,000**	**11,312**	**11,039**	**13,175**	**13,956**	**13,956**	**13,446**	**13,108**	**12,689**	**12,587**	**12,432**	**14,219**	**14,219**	**14,219**	**14,258**	**14,932**	**14,247**	**14,247**	**15,492**	**15,546**
Existing Units	*$000*		7,189	7,189	7,189	7,209	7,189	6,487	6,207	6,224	5,749	4,919	4,331	4,039	3,710	3,710	3,710	3,171	2,861	2,443	2,147	1,964	1,772	1,772	1,772	1,777	879	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	-	-	179	982	1,786	1,790	2,589	2,589	2,589	2,596	2,589	2,589	2,589	2,596	3,393	3,393	3,393	3,402	5,000	5,000	5,000	5,013	5,000
DG Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	*$000*		-	-	-	-	481	962	1,443	1,829	1,824	1,824	1,824	1,829	2,204	2,585	2,585	2,592	2,585	2,585	2,585	2,592	2,585	2,585	2,585	2,592	2,585	2,585	2,585	2,592	2,585
Utility Wind	*$000*		-	-	-	-	-	-	97	387	869	869	965	968	1,062	1,062	1,062	1,065	1,062	1,062	1,255	1,258	1,255	1,255	1,255	1,258	1,255	1,448	1,448	1,452	1,544
Waste to Energy	*$000*		-	-	-	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025
Landfill Gas	*$000*		-	-	-	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181
Battery	*$000*		-	-	-	-	-	201	201	201	201	201	201	201	1,404	1,805	1,805	1,810	1,805	1,805	1,805	1,810	3,008	3,008	3,008	3,016	3,008	3,008	3,008	4,223	4,212
Variable O&M	$000		**1,779**	**1,783**	**1,795**	**2,075**	**1,920**	**1,776**	**1,611**	**1,454**	**1,382**	**1,384**	**1,381**	**1,396**	**1,336**	**1,181**	**1,190**	**1,204**	**1,215**	**1,228**	**1,222**	**1,235**	**1,245**	**1,258**	**1,274**	**1,293**	**1,302**	**1,295**	**1,307**	**1,323**	**1,326**
Existing Units	*$000*		1,779	1,783	1,795	1,679	1,526	1,382	1,216	1,063	939	668	432	436	201	84	89	98	112	125	132	143	30	34	39	44	1	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	-	-	54	328	562	573	754	713	717	721	718	719	706	707	831	839	851	864	916	910	923	938	942
DG Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Wind	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	*$000*		-	-	-	336	335	335	335	332	330	329	329	330	324	326	326	327	326	326	326	327	326	326	326	327	327	326	326	327	326
Landfill Gas	*$000*		-	-	-	60	60	60	60	59	59	59	58	59	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
Battery	*$000*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPEX (Ammortized)			**14,315**	**15,666**	**16,746**	**23,054**	**28,247**	**32,727**	**36,651**	**41,347**	**43,298**	**43,415**	**44,488**	**44,046**	**48,161**	**55,293**	**55,345**	**54,449**	**53,743**	**52,953**	**53,295**	**53,106**	**53,173**	**53,225**	**53,264**	**126,972**	**54,890**	**54,015**	**54,015**	**54,163**	**54,447**
CAPEX (Total Spend)			**25,950**	**13,348**	**14,386**	**174,578**	**65,308**	**91,448**	**63,733**	**64,953**	**48,784**	**44,066**	**40,185**	**8,409**	**68,525**	**79,739**	**7,329**	**7,329**	**5,653**	**5,653**	**14,396**	**4,242**	**28,186**	**3,501**	**3,501**	**86,653**	**52,476**	**10,049**	**-**	**-**	**5,006**
Existing Units	*$000*		12,958	13,348	14,386	14,699	15,629	14,204	12,264	12,264	12,264	10,103	9,441	8,409	7,329	7,329	7,329	7,329	5,653	5,653	4,242	4,242	3,501	3,501	3,501	3,501	3,501	-	-	-	-
New Diesel Units	*$000*		-	-	-	-	-	-	-	-	7,562	33,963	25,183	-	25,083	-	-	-	-	-	-	-	24,684	-	-	83,151	48,975	-	-	-	-
DG Solar	*$000*																														
PV Solar	*$000*		12,993	-	-	-	49,680	47,282	45,424	34,944	-	-	-	-	30,776	30,098	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Wind	*$000*		-	-	-	-	-	-	6,046	17,745	28,958	-	5,560	-	5,337	-	-	-	-	-	10,153	-	-	-	-	-	-	10,049	-	-	5,006
Waste to Energy	*$000*		-	-	-	73,820	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Landfill Gas	*$000*		-	-	-	2,659	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery	*$000*		-	-	-	-	-	29,962	-	-	-	-	-	-	-	42,312	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conversion Costs	*$000*					83,400																									
TOTAL COST	**$000**		**107,336**	**116,710**	**123,113**	**107,577**	**107,189**	**105,900**	**102,919**	**101,595**	**100,652**	**100,234**	**101,021**	**100,949**	**104,209**	**104,890**	**105,492**	**104,874**	**104,385**	**103,780**	**103,836**	**104,047**	**106,024**	**106,842**	**107,852**	**182,593**	**111,643**	**109,915**	**110,582**	**112,852**	**113,473**
Gross Energy Generation	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Thermal Generation	MWh		**656,322**	**657,877**	**662,364**	**619,600**	**563,089**	**509,913**	**448,821**	**392,167**	**366,723**	**367,775**	**366,692**	**372,033**	**352,216**	**293,995**	**297,444**	**302,234**	**306,478**	**311,340**	**309,213**	**313,580**	**317,638**	**322,310**	**328,291**	**334,890**	**338,399**	**335,955**	**340,495**	**346,209**	**347,755**
Existing	*MWh*		656,322	657,877	662,364	619,600	563,089	509,913	448,821	392,167	346,655	246,606	159,228	160,711	74,028	30,869	32,850	36,144	41,349	46,074	48,754	52,693	10,946	12,683	14,403	16,168	404	-	-	-	-
New	*MWh*		-	-	-	-	-	-	-	-	20,067	121,169	207,463	211,322	278,188	263,127	264,594	266,090	265,129	265,266	260,459	260,886	306,692	309,626	313,888	318,722	337,995	335,955	340,495	346,209	347,755
Renewable	MWh		**15,074**	**21,739**	**24,612**	**74,401**	**134,740**	**195,808**	**263,657**	**329,514**	**359,125**	**363,932**	**370,687**	**374,312**	**400,262**	**470,618**	**472,757**	**476,141**	**476,425**	**478,207**	**487,798**	**490,733**	**491,031**	**492,768**	**494,488**	**497,855**	**499,269**	**508,010**	**509,983**	**513,755**	**517,347**
DG Solar	*MWh*		8,718	10,394	13,289	18,271	22,058	26,373	31,484	37,406	43,676	50,357	54,262	58,122	61,468	64,748	67,656	70,511	72,654	74,822	76,724	78,682	80,350	82,173	84,247	86,572	88,520	90,761	93,043	95,643	97,817
PV Solar	*MWh*		6,356	11,345	11,322	11,332	68,021	124,773	181,295	223,907	220,800	219,771	218,748	218,308	245,822	303,891	303,296	303,474	301,832	301,275	300,591	301,083	300,090	300,003	299,635	300,160	299,614	298,439	298,354	298,807	297,248
Mastic Wind	*MWh*		-	-	-	-	-	-	6,247	23,875	46,398	45,703	45,534	45,625	39,227	45,748	45,612	45,846	45,715	45,889	45,859	46,063	45,888	45,856	45,921	46,131	46,184	45,837	45,656	46,031	45,505
Quarry Wind	*MWh*		-	-	-	-	-	-	-	-	4,290	4,197	8,297	8,312	10,569	12,714	12,697	12,692	12,726	12,703	21,162	21,313	21,219	21,231	21,168	21,336	21,395	29,489	29,436	29,660	33,301
Waste to Energy	*MWh*		-	-	-	37,331	37,218	37,217	37,189	36,934	36,632	36,584	36,536	36,618	35,978	36,261	36,243	36,345	36,246	36,261	36,212	36,325	36,235	36,251	36,259	36,376	36,293	36,234	36,242	36,340	36,227
Landfill Gas	*MWh*		-	-	-	7,466	7,444	7,446	7,441	7,392	7,329	7,320	7,311	7,327	7,198	7,256	7,253	7,273	7,253	7,256	7,249	7,267	7,249	7,254	7,259	7,279	7,263	7,251	7,252	7,274	7,249
Total	**MWh**		**671,397**	**679,616**	**686,976**	**694,000**	**697,829**	**705,721**	**712,478**	**721,681**	**725,847**	**731,708**	**737,378**	**746,345**	**752,478**	**764,613**	**770,201**	**778,375**	**782,903**	**789,547**	**797,011**	**804,313**	**808,669**	**815,078**	**822,779**	**832,745**	**837,668**	**843,965**	**850,478**	**859,964**	**865,102**
OPERATIONS																															
Renewable Curtailment	*percent*		1.72	2.48	2.81	3.37	10.29	17.25	25.01	32.98	37.06	37.78	38.72	39.12	45.19	50.70	50.98	51.23	51.42	51.61	52.85	53.02	53.16	53.31	53.49	53.69	53.86	55.15	55.36	55.61	56.39
Renewable Curtailed Energy	*MWh*		-	-	-	-	50	1	76	4,489	9,479	10,896	12,375	13,222	38,781	17,040	17,297	17,451	17,523	17,449	18,669	18,501	18,127	17,709	17,608	17,346	16,112	18,574	18,494	18,327	20,135
Spinning Requirement	*MW*		*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*
Regulation Requirements	*MW*		*0.48*	*0.83*	*0.84*	*0.86*	*4.82*	*8.79*	*13.18*	*17.31*	*19.01*	*18.91*	*19.12*	*19.08*	*20.73*	*25.37*	*25.32*	*25.28*	*25.27*	*25.25*	*25.76*	*25.75*	*25.75*	*25.75*	*25.75*	*25.75*	*25.78*	*26.23*	*26.22*	*26.25*	*26.44*
Reserve Margin	*percent*		*55.65*	*52.31*	*51.02*	*54.76*	*53.76*	*67.48*	*50.35*	*50.54*	*55.07*	*48.28*	*46.67*	*45.77*	*50.31*	*84.42*	*83.33*	*79.69*	*64.89*	*63.95*	*50.11*	*49.26*	*56.48*	*55.54*	*54.61*	*53.69*	*82.34*	*49.56*	*48.70*	*47.86*	*47.34*
Fuel Consumption Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Diesel	MMBtu		5,541,602	5,555,095	5,593,596	8,504	7,087	1,543	1,094	1,350	3,733	607	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	MMBtu		-	-	-	5,216,121	4,735,623	4,303,398	3,792,007	3,313,876	3,083,486	3,036,513	2,990,842	3,034,998	2,833,393	2,345,617	2,373,570	2,413,661	2,448,624	2,490,609	2,474,463	2,509,698	2,523,014	2,561,054	2,609,104	2,662,082	2,684,183	2,664,661	2,701,008	2,746,840	2,758,023

Portfolio 6 Base		Fiscal Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
COST	**Unit**																														
Total Costs	*$000*		**107,340**	**116,708**	**123,113**	**107,577**	**109,421**	**108,522**	**105,636**	**104,514**	**105,128**	**108,429**	**108,981**	**109,535**	**112,003**	**112,619**	**113,239**	**112,667**	**114,332**	**113,733**	**116,500**	**116,760**	**116,513**	**117,299**	**118,302**	**119,551**	**117,251**	**120,240**	**120,911**	**123,811**	**124,501**
Fuel Costs	*$000*		84,057	92,070	97,383	73,027	64,523	58,339	51,999	47,402	39,823	38,817	37,417	37,479	35,693	36,259	36,817	37,622	37,835	38,431	36,895	37,451	37,781	38,502	39,450	40,415	40,982	41,637	42,295	43,149	43,006
Fixed Costs	*$000*		7,189	7,189	7,189	9,421	15,675	16,637	16,839	17,266	24,125	27,768	29,146	30,086	31,982	31,982	31,982	31,521	31,937	31,519	32,509	32,409	31,734	31,734	31,734	31,821	30,841	31,569	31,569	33,041	33,144
Variable Costs	*$000*		1,779	1,783	1,795	2,075	1,862	1,703	1,554	1,443	1,267	1,259	1,240	1,242	1,210	1,221	1,230	1,244	1,254	1,267	1,233	1,247	1,256	1,269	1,285	1,304	1,313	1,325	1,337	1,354	1,347
CAPEX (New & Existing Units)	*$000*		14,315	15,666	16,746	23,054	27,361	31,842	35,244	38,402	39,912	40,586	41,179	40,728	43,118	43,157	43,210	42,280	43,306	42,516	45,863	45,653	45,741	45,793	45,832	46,010	44,115	45,709	45,709	46,267	47,004
$/KWh Costs			0.16	0.17	0.18	0.16	0.16	0.15	0.15	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
NPV ($1000), Discount Rate 5.5%	***$1,611,784***																														
ENVIRONMENTAL COMPLIANCE																															
Emissions Amounts (CO2 Tons)	*Tons*		*443,354*	*444,397*	*447,486*	*311,039*	*271,289*	*242,850*	*215,306*	*194,988*	*162,753*	*157,830*	*151,841*	*152,177*	*144,874*	*146,852*	*148,562*	*151,038*	*151,773*	*154,303*	*147,903*	*150,065*	*151,715*	*153,844*	*156,674*	*159,782*	*161,560*	*163,578*	*165,744*	*168,427*	*167,441*
Emission Compliance Target (CO2 Tons) Only for 4-6	*Tons*		*441,463*	*455,903*	*464,271*	*471,235*	*440,709*	*410,183*	*379,657*	*349,131*	*318,605*	*288,868*	*259,132*	*229,395*	*199,659*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*	*169,922*
Renewable Penetration (generation basis)	*percent*		*2.25%*	*3.20%*	*3.58%*	*10.72%*	*22.39%*	*31.57%*	*39.94%*	*46.29%*	*55.33%*	*56.06%*	*57.30%*	*57.74%*	*59.50%*	*59.32%*	*59.16%*	*58.97%*	*58.69%*	*58.43%*	*60.33%*	*60.13%*	*59.85%*	*59.61%*	*59.27%*	*58.96%*	*58.77%*	*58.56%*	*58.35%*	*58.14%*	*58.61%*
Operating Costs Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Fuel	$000		**84,057**	**92,070**	**97,383**	**73,027**	**64,523**	**58,339**	**51,999**	**47,402**	**39,823**	**38,817**	**37,417**	**37,479**	**35,693**	**36,259**	**36,817**	**37,622**	**37,835**	**38,431**	**36,895**	**37,451**	**37,781**	**38,502**	**39,450**	**40,415**	**40,982**	**41,637**	**42,295**	**43,149**	**43,006**
Existing	$000		84,057	92,070	97,383	73,027	64,523	58,339	51,999	47,402	39,823	28,787	16,303	16,378	6,508	6,963	7,402	8,105	2,767	3,264	637	871	125	146	183	239	153	-	-	-	-
New	$000		-	-	-	-	-	-	-	-	-	10,030	21,114	21,101	29,185	29,296	29,415	29,517	35,067	35,167	36,258	36,580	37,657	38,357	39,268	40,176	40,829	41,637	42,295	43,149	43,006
Fixed Costs	$000		**7,189**	**7,189**	**7,189**	**9,421**	**15,675**	**16,637**	**16,839**	**17,266**	**24,125**	**27,768**	**29,146**	**30,086**	**31,982**	**31,982**	**31,982**	**31,521**	**31,937**	**31,519**	**32,509**	**32,409**	**31,734**	**31,734**	**31,734**	**31,821**	**30,841**	**31,569**	**31,569**	**33,041**	**33,144**
Existing Units	$000		7,189	7,189	7,189	7,209	7,189	6,487	6,207	6,224	5,749	4,919	4,331	4,039	3,710	3,710	3,710	3,171	2,861	2,443	2,147	1,964	1,772	1,772	1,772	1,777	879	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	-	-	-	714	1,518	1,522	2,321	2,321	2,321	2,328	3,125	3,125	3,928	3,939	4,732	4,732	4,732	4,745	4,732	6,339	6,339	6,535	6,517
DG Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	$000		-	-	-	-	381	862	1,343	1,728	1,723	1,723	1,723	1,728	1,723	1,723	1,723	1,728	1,723	1,723	1,723	1,728	1,723	1,723	1,723	1,728	1,723	1,723	1,723	1,728	1,723
Utility Wind	$000		-	-	-	-	-	-	-	-	483	579	579	581	869	869	869	871	869	869	1,351	1,355	1,351	1,351	1,351	1,355	1,351	1,351	1,351	1,355	1,544
Waste to Energy	$000		-	-	-	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025	2,025	2,025	2,031	2,025
Landfill Gas	$000		-	-	-	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181	181
Battery	$000		-	-	-	-	-	201	201	201	201	201	201	201	1,404	1,404	1,404	1,408	1,404	1,404	1,404	1,408	201	201	201	201	201	201	201	1,408	1,404
OTEC	$000		-	-	-	-	5,899	6,882	6,882	6,901	13,764	17,426	18,588	19,803	19,749	19,749	19,749	19,803	19,749	19,749	19,749	19,803	19,749	19,749	19,749	19,803	19,749	19,749	19,749	19,803	19,749
Variable O&M	$000		**1,779**	**1,783**	**1,795**	**2,075**	**1,862**	**1,703**	**1,554**	**1,443**	**1,267**	**1,259**	**1,240**	**1,242**	**1,210**	**1,221**	**1,230**	**1,244**	**1,254**	**1,267**	**1,233**	**1,247**	**1,256**	**1,269**	**1,285**	**1,304**	**1,313**	**1,325**	**1,337**	**1,354**	**1,347**
Existing Units	$000		1,779	1,783	1,795	1,679	1,468	1,309	1,160	1,050	879	635	359	360	143	152	162	176	60	70	13	18	3	3	4	5	3	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	-	-	-	237	495	495	683	684	684	683	810	813	837	844	871	883	898	914	926	941	953	969	964
DG Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PV Solar	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Wind	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Waste to Energy	$000		-	-	-	336	335	335	335	334	329	329	328	328	326	326	326	327	326	326	325	326	325	325	326	327	326	326	326	327	326
Landfill Gas	$000		-	-	-	60	60	60	60	59	59	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58	58
Battery	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OTEC	$000		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CAPEX (Ammortized)			**14,315**	**15,666**	**16,746**	**23,054**	**27,361**	**31,842**	**35,244**	**38,402**	**39,912**	**40,586**	**41,179**	**40,728**	**43,118**	**43,157**	**43,210**	**42,280**	**43,306**	**42,516**	**45,863**	**45,653**	**45,741**	**45,793**	**45,832**	**46,010**	**44,115**	**45,709**	**45,709**	**46,267**	**47,004**
CAPEX (Total Spend)			**25,950**	**13,348**	**14,386**	**174,578**	**55,037**	**91,448**	**57,688**	**47,208**	**41,222**	**45,967**	**34,625**	**8,409**	**48,424**	**7,329**	**7,329**	**7,329**	**30,536**	**5,653**	**54,409**	**4,242**	**28,186**	**3,501**	**3,501**	**3,501**	**3,501**	**48,877**	**-**	**7,280**	**10,012**
Existing Units	$000		12,958	13,348	14,386	14,699	15,629	14,204	12,264	12,264	12,264	10,103	9,441	8,409	7,329	7,329	7,329	7,329	5,653	5,653	4,242	4,242	3,501	3,501	3,501	3,501	3,501	-	-	-	-
New Diesel Units	$000		-	-	-	-	-	-	-	-	-	30,189	25,183	-	25,083	-	-	-	24,883	-	24,783	-	24,684	-	-	-	-	48,877	-	7,280	-
DG Solar	$000																														
PV Solar	$000		12,993	-	-	-	39,408	47,282	45,424	34,944	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utility Wind	$000		-	-	-	-	-	-	-	-	28,958	5,675	-	-	16,012	-	-	-	-	-	25,383	-	-	-	-	-	-	-	-	-	10,012
Waste to Energy	$000		-	-	-	73,820	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Landfill Gas	$000		-	-	-	2,659	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery	$000		-	-	-	-	-	29,962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Conversion Costs	$000					83,400																									
TOTAL COST	**$000**		**107,340**	**116,708**	**123,113**	**107,577**	**109,421**	**108,522**	**105,636**	**104,514**	**105,128**	**108,429**	**108,981**	**109,535**	**112,003**	**112,619**	**113,239**	**112,667**	**114,332**	**113,733**	**116,500**	**116,760**	**116,513**	**117,299**	**118,302**	**119,551**	**117,251**	**120,240**	**120,911**	**123,811**	**124,501**
Gross Energy Generation	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Thermal Generation	MWh		**656,322**	**657,877**	**662,364**	**619,600**	**541,574**	**482,987**	**427,938**	**387,534**	**324,270**	**321,575**	**315,046**	**315,523**	**304,705**	**308,602**	**312,105**	**316,855**	**320,905**	**325,688**	**313,762**	**318,284**	**322,263**	**326,816**	**332,714**	**339,324**	**342,910**	**347,292**	**351,738**	**357,418**	**355,603**
Existing	MWh		656,322	657,877	662,364	619,600	541,574	482,987	427,938	387,534	324,270	234,228	132,547	132,962	52,733	56,233	59,659	64,849	22,005	25,743	4,776	6,826	985	1,148	1,438	1,879	1,215	-	-	-	-
New	MWh		-	-	-	-	-	-	-	-	-	87,347	182,500	182,560	251,972	252,369	252,446	252,006	298,900	299,945	308,986	311,458	321,278	325,668	331,276	337,445	341,695	347,292	351,738	357,418	355,603
Renewable	MWh		**15,074**	**21,739**	**24,612**	**74,401**	**156,255**	**222,854**	**284,539**	**334,003**	**401,692**	**410,199**	**422,688**	**431,091**	**447,630**	**449,992**	**452,063**	**455,448**	**455,927**	**457,755**	**477,206**	**479,975**	**480,444**	**482,357**	**484,135**	**487,487**	**488,833**	**490,690**	**492,724**	**496,478**	**503,482**
DG Solar	MWh		8,718	10,394	13,289	18,271	22,058	26,373	31,484	37,406	43,676	50,357	54,262	58,122	61,468	64,748	67,656	70,511	72,654	74,822	76,724	78,682	80,350	82,173	84,247	86,572	88,520	90,761	93,043	95,643	97,817
PV Solar	MWh		6,356	11,345	11,322	11,332	56,625	113,428	170,011	213,606	208,744	206,921	205,220	204,293	202,598	201,954	201,266	201,215	200,111	199,781	198,973	199,191	199,572	199,109	198,874	199,233	197,958	197,157	196,906	197,350	195,897
Mastic Wind	MWh		-	-	-	-	-	-	-	-	28,536	28,126	27,605	27,406	42,896	42,663	42,517	42,767	42,519	42,491	42,263	42,455	41,637	41,933	41,770	41,992	42,640	42,971	42,945	43,199	42,514
Quarry Wind	MWh		-	-	-	-	-	-	-	-	-	4,166	4,081	4,019	3,876	3,852	3,857	3,886	3,870	3,878	22,626	22,712	22,245	22,464	22,554	22,686	23,002	23,071	23,102	23,213	30,574
OTEC	MWh		-	-	-	-	32,913	38,398	38,401	38,480	76,808	76,808	87,791	93,463	93,275	93,275	93,275	93,463	93,275	93,275	93,275	93,463	93,275	93,275	93,275	93,463	93,275	93,275	93,275	93,463	93,275
Waste to Energy	MWh		-	-	-	37,331	37,216	37,209	37,201	37,090	36,603	36,515	36,439	36,487	36,261	36,247	36,240	36,337	36,246	36,253	36,117	36,224	36,135	36,165	36,176	36,282	36,195	36,209	36,208	36,337	36,168
Landfill Gas	MWh		-	-	-	7,466	7,444	7,445	7,443	7,421	7,325	7,305	7,291	7,301	7,255	7,253	7,251	7,271	7,252	7,254	7,227	7,248	7,231	7,237	7,238	7,259	7,242	7,246	7,245	7,273	7,236
Total	**MWh**		**671,397**	**679,616**	**686,976**	**694,001**	**697,829**	**705,841**	**712,477**	**721,537**	**725,962**	**731,774**	**737,735**	**746,613**	**752,335**	**758,594**	**764,168**	**772,303**	**776,832**	**783,443**	**790,967**	**798,258**	**802,708**	**809,173**	**816,848**	**826,812**	**831,744**	**837,982**	**844,463**	**853,895**	**859,085**
OPERATIONS																															
Renewable Curtailment	*percent*		1.72	2.48	2.81	3.37	12.75	20.34	27.39	33.21	41.85	43.12	44.77	45.79	48.28	48.62	48.91	49.18	49.39	49.60	52.50	52.67	52.84	53.01	53.21	53.42	53.63	53.84	54.07	54.33	55.68
Renewable Curtailed Energy	*MWh*		-	-	-	-	96	6	32	2,204	8,854	11,318	13,261	14,839	18,849	19,385	19,872	20,075	20,271	20,290	26,067	26,102	25,826	25,443	25,443	25,237	24,368	24,415	24,400	24,291	27,663
Spinning Requirement	*MW*		*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*	*21*
Regulation Requirements	*MW*		*0.48*	*0.83*	*0.84*	*0.86*	*4.03*	*8.00*	*11.96*	*14.96*	*16.65*	*16.81*	*16.66*	*16.56*	*17.52*	*17.46*	*17.41*	*17.38*	*17.36*	*17.34*	*18.55*	*18.53*	*18.53*	*18.54*	*18.54*	*18.55*	*18.57*	*18.55*	*18.55*	*18.57*	*18.99*
Reserve Margin	*percent*		*55.65*	*52.31*	*51.02*	*54.76*	*59.54*	*73.23*	*55.69*	*54.71*	*59.39*	*50.78*	*48.78*	*47.87*	*52.04*	*51.13*	*50.24*	*46.79*	*47.66*	*46.81*	*47.68*	*46.84*	*54.07*	*53.15*	*52.23*	*51.33*	*50.44*	*46.55*	*45.71*	*48.11*	*47.26*
Fuel Consumption Summary	**Unit**		**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Diesel	MMBtu		5,541,919	5,554,962	5,593,569	8,523	2,989	2,268	1,146	1,130	2,152	186	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	MMBtu		-	-	-	5,216,089	4,555,463	4,078,466	3,617,042	3,275,591	2,732,458	2,652,350	2,551,958	2,557,595	2,434,861	2,468,104	2,496,836	2,538,451	2,550,806	2,593,331	2,485,757	2,522,100	2,549,824	2,585,607	2,633,172	2,685,418	2,715,296	2,749,216	2,785,605	2,830,698	2,814,139