Cayman Islands Value of Solar Study

NOVEMBER 30TH, 2022

Prepared for: The Utility Regulation and Competition Office of the Cayman Islands (OfReg)

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List of Acronyms

ATB	Annual Technology Baseline
BAU	Business-as-usual
BESS	Battery Energy Storage System
BTU	British Thermal Unit
CARILEC	Caribbean Electric Utility Services Corporation
CCA	The Cayman Contractor's Association
CEPA	Cambridge Economic Policy Associates
CF	Capacity Factor
CH4	Methane
CME	Chicago Mercantile Exchange
CO2	Carbon Dioxide
CORE	Consumer Owned Renewable Energy
CPI	Consumer Price Index
CREA	Cayman Renewable Energy Association
CUC	Caribbean Utilities Company
DC	Direct Current
DER	Distributed Energy Resources
DG	Distributed Generation
DOE	Cayman Islands Department of Environment
DOP	Cayman Islands Department of Planning
DSG	Distributed Solar Generation
EIA	Energy Information Administration
EMS	Environmental Management System
EPA	U.S. Environmental Protection Agency
EPC	The Cayman Energy Policy Council
ERA	Electricity Regulatory Authority
FIT	Feed-In Tariff
FOM	Fixed Operations & Maintenance Costs
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GVA	Gross Value Added
GW	Gigawatt
IPP	Independent Power Producer
IREC	Interstate Renewable Energy Council, Inc.
IRP	Integrated Resource Plan
ISO	International Organization for Standardization

KYD	Cayman Islands Dollar
LCOE	Levelized Cost of Energy
LPSC	Louisiana Public Service Commission
MMBtu	Metric Million British Thermal Unit
MVA	Megavolt Ampere
MW	Megawatt
N2O	Nitrous Oxide
NEP	National Energy Policy
NG	Natural Gas
NHDT	National Housing Development Trust Cayman
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
OPEC	Organization of the Petroleum Exporting Countries
PGE	Pacific Gas and Electric
PPA	Power Purchase Agreement
PV	Photovoltaic
RE	Renewable Energy
RMI	Rocky Mountain Institute
SF	Sustainability Factor
UK	United Kingdom
ULSD	Ultra-low-sulfur diesel
UNECE	United Nations Economic Commission for Europe
US	United States
USAID	United States Agency for International Development
USD	United States Dollar
USDA	United States Department of Agriculture
VOLL	Value of Lost Load
VOM	Variable Operations & Maintenance Cost
VOS	Value of Solar
WTE	Waste-to-Energy

1. Executive Summary

The Utility Regulation and Competition Office (OfReg) engaged RMI (formerly Rocky Mountain Institute) in 2022 to conduct a value of solar ("VOS") study for the Cayman Islands' territory served by Caribbean Utilities Company, Ltd (CUC). The increasing demand for distributed solar generation (DSG) is driving a heated debate about how to best facilitate the integration of DSG and what benefits it creates or costs it imposes to stakeholders within the electricity system. The VOS represents the value or net benefit/cost of gross energy produced by solar PV. For this study, RMI reviewed a variety of approaches and quantitative tools used by different parties in different jurisdictions including Hawaii (an island state with high solar penetration values). However, stakeholder interviews and analyses were conducted to identify variables that were not applicable to the Cayman Islands and identify those unique to the Cayman or small island context. The VOS study analyzed various variables that can be categorized by those having utility and grid impact, those which are risk based, and those having an environmental or economic impact. RMI also identified several variables that were not used or were not applicable to the Cayman Islands. The value or cost of each variable was calculated separately using established methodologies. Economic and technical data was provided by OfReg, CUC, and other stakeholders. Given the level of work and stakeholder engagement and alignment taken during the development of the 2017 Cayman Islands Integrated Resource Plan (IRP), RMI adopted the baseline assumptions used in the IRP when applicable. These assumptions were updated for deviations from the plan through 2022 and for any significant adjustments required based upon new information received from stakeholders. Other assumptions outlined in the report are based upon industry best practices, RMI's experience working in the Caribbean region and input from Caymanian stakeholders. Of the twenty two (22) independent variables considered, sixteen (16) were included in the VOS study, are summarized in Exhibit 1, and are segmented into the three impact categories. Variables not considered for the purpose of this report are discussed in section seven (7). Each variable was specifically identified and chosen for this VOS study based on the local context in the Cayman Islands.

Direct Utility Impact (Energy/Grid)		Definition and Cayman Context
1.	Net avoided energy costs	This is the avoided cost that would have otherwise been generated at a centralized fossil fuel power plant. Transitioning to a renewable power system helps the Cayman Islands to reduce dependency on foreign markets and avoid inefficiencies in traditional fossil fuel plants.
2.	System Losses	This represents the value of the additional energy generated by CUC's central plants that would otherwise be lost due to inherent inefficiencies in delivering energy to the customer via the transmission and distribution system.
3.	Net avoided Generation Capacity	This represents the avoided build cost of central generation capacity that can be deferred or avoided due to the addition of distributed or utility scale solar generators. Switching from a centralized system to a distributed generation will require less utility-scale generation capacity investment for the island.
4.	Avoided Transmission Capacity	This represents the avoided cost and amount of transmission infrastructure investments needed for the grid due to distributed solar generation installation. Switching from a centralized system to a distributed generation will entail less transmission system investment for the island.
5.	Avoided Distribution Capacity	This represents the avoided cost and amount of distribution infrastructure investments needed for the grid due to distributed solar generation installation. Switching from a centralized system to a distributed generation will entail less distribution system investment for the island.

6.	Avoided Reserve Capacity	This represents the avoided cost and amount of grid support needed. The addition of utility scaled storage to balance the grid will be necessary when integrating the intermittent solar resource.
7.	Integration Costs	These are the costs incurred by the utility to integrate and manage distributed solar and utility scale solar on the power grid. Investments may be required to support voltage regulation, upgrade transformers, increase available fault duty, and provide anti-islanding protection.
Risk Impact		
8.	Fuel Price Volatility	This reflects the avoided fuel hedging costs to the utility based on the reduced risk and exposure to the volatile fuel prices of conventional generation resources. Fuel prices are very susceptible to local and global events and have been very particularly volatile in recent times with the Ukrainian crisis and COVID shutdowns. These types of incidents will continue to happen moving forward and independency from fuel prices will be strategic.
9.	Reliability and Resiliency	This represents the value of avoided outages based on the total cost of power outages each year, and the perceived ability of distributed and utility scale solar generation to decrease the incidence of outages. Distributed solar generation can add resiliency to the power system during power outages and blackouts. There is an increasing frequency of hurricanes, blackouts, and natural disasters as a result of a changing climate and ensuring power grid resiliency is crucial.
10.	Market Price Response	This reflects the market reaction of reduced prices and subsequent market dynamics in light of higher penetrations of distributed solar generation, which has no variable O&M or fuel costs.
Environmental/Economic Impact		
11.	Net carbon Emissions	This reflects the reduction in carbon emissions resulting from solar or the amount of carbon displaced times the price of reducing a ton of carbon.
12.	Other pollutants	This is the cost of avoided abatement technologies, the market value of pollutant reductions, and/or the cost of human health damages due to the integration of more sustainable solar systems.
13.	Net water Use	This represents the reduced water usage when transitioning to solar power generation. It examines the cost or value of water with competing energy technologies.
14.	Net avoided Land Impact	This represents the offset of ecosystem impacts due to the penetration of distributed solar generation. It includes the reduced pollutants and the avoided spillage during the production process. Distributed solar helps to reduce pollutants on land and in sensitive habitats, adds value through land reclamation and can function as dual use (animal grazing, agricultural production, etc.) which increases land value and increases viable land for use.
15.	Land Use	This represents the value of the required land needed for distributed or utility scale solar generation installations. There is lack of land resource available to small island nations, which results in high land costs.
16.	Economic Development	This encompasses the increase in employment and tax revenue due to additional distributed or utility scale solar generation. Local capacity building and employment in the renewable energy sector will make the island a leader in the region moving forward.

Exhibit 1: The 16 VOS variables used in the study along with their definition and local context

In addition to variable selection, a key part of the VOS study involved understanding the importance of each variable based on stakeholder input and interviews. Representing the opinions and priorities of each stakeholder group in the final value of solar was a key step to ensuring that opinions were considered in the evaluation, which would increase transparency and a better understanding of the results. As part of the stakeholder engagement process, a variable matrix and survey was created for stakeholders and stakeholder groups to indicate the relative importance of each variable in the VOS study. The responses to these surveys were used to provide additional context or identify variables that were most important to stakeholders. The results of this analysis are included as Exhibit 2.

No.	Variable	Weighted Average Variable Score (out of 10)	Variable Percentage Value (%)
1	Net avoided energy value	8.62	7.41%
2	System Losses Value	5.88	5.05%
3	Fuel price volatility value	8.35	7.17%
4	Net generation capacity value	7.50	6.44%
5	Transmission capacity value	5.41	4.65%
6	Distribution capacity value	6.19	5.32%
7	Ancillary services value	8.18	7.03%
8	Reliability and resiliency risk value	7.60	6.53%
9	Market price response value	7.76	6.66%
10	Net carbon emissions value	8.64	7.43%
11	Other air pollutants value	8.58	7.37%
12	Net water impact value	5.98	5.14%
13	Net land impact value 1 (ecosystem impacts)	8.34	7.17%
14	Land impact value 2 (impact on land values)	5.55	4.77%
15	Economic development value	7.01	6.02%
16	Integration Costs	6.82	5.86%
	Total	116.39	100.00%

Exhibit 2: Final stakeholder weightings based on engagements during the VOS study

A key part of the study was to create and forecast the operation of a simulated PV fleet for the VOS analysis period (2022-2052) that reflected the preferred expansion plan in the 2017 IRP and the goals of the National Energy Policy. The RMI team used characteristics of historic Cayman Islands solar systems to create similar systems coming online in future years. The team then used the National Renewable Energy Lab's (NREL's) PV Watts tool to forecast the hourly PV production of the distributed solar and utility scale solar fleets from 2022 until 2052.

This PV production forecast, in addition to a robust demand forecast, formed the starting point of the analysis. Along with other key assumptions and inputs, this allowed the team to begin calculating the respective value of solar for each variable. Methodologies for determining the VOS for each variable were heavily researched, analyzed against previous VOS reports, regional renewable energy and energy data, information gleaned or collected from key stakeholders and stakeholder groups, and educated assumptions based on accepted standards in the Caribbean region and power sector. Each methodology determined a unique manner to capture the variable in a numerical manner of avoided costs [$] or additional costs [$] per kWh of the theoretical solar generated from the simulated PV fleets.

The final results from the analysis are shown in Exhibit 3, and are broken down by impact category.

Direct Utility Impact (Energy/Grid)		Distributed VOS [USD/kWh]	Percentage of Total VOS	Utility VOS [USD/kWh]	Percentage of Total VOS
1.	Net avoided energy costs	0.171	59%	0.157	61%
2.	System Losses	0.005	2%	0.000	0%
3.	Net avoided Generation Capacity	0.027	9%	0.042	16%
4.	Avoided Transmission Capacity	0.001	0%	0.000	0%
5.	Avoided Distribution Capacity	0.008	3%	0.000	0%
6.	Avoided Reserve Capacity	0.009	3%	0.015	6%
7.	Integration Costs	-0.0023	-1%	-0.033	-13%
	VOS Subtotal – Direct Utility Impact:	0.219		0.182	
Risk Impact					
8.	Fuel Price Volatility	0.004	1%	0.002	1%
9.	Reliability and Resiliency	0.008	3%	0.003	1%
10.	Market Price Response	0.000	0%	0.019	7%
	VOS Subtotal – Risk Impact	0.012		0.024	
Environmental/Economic Impact					
11.	Net carbon Emissions	0.028	9%	0.026	10%
12.	Other pollutants	0.000	0%	0.000	0%
13.	Net water Use	0.007	2%	0.005	2%
14.	Net avoided Land Impact	0.000	0%	0.000	0%
15.	Land Use	-0.001	0%	-0.017	-7%
16.	Net economic Development	0.026	9%	0.038	15%
	VOS Subtotal – Environmental/ Economic Impact	0.06		0.052	
	TOTAL:	**0.291**		**0.257**	

Exhibit 3: The 16 VOS results and the percentage of the total VOS value for distributed and utility scale solar

The overall VOS value for distributed solar generation (DSG) in the Cayman Islands was calculated at USD 0.291/kWh. While the VOS value for utility-scale solar was USD 0.257/kWh. For both VOS values, the direct utility impact, which includes net avoided energy costs, and grid, transmission, distribution, and generation impacts, accounted for the majority of the VOS value: 75.3% of the distributed VOS and 70.8% of the utility VOS. Risk impact accounts for 4.1% of the distributed VOS and 9.3% of the utility VOS. While the environmental/economic impact makes up 20.6% and 20.2% of the distributed and utility VOS values respectively.

The most significant driver of the value of solar in the Cayman Islands is the avoided cost of fuel, included among the net avoided energy costs variable, which is also comprised of avoided fixed operations & maintenance (O&M) costs, and avoided variable O&M costs. Avoided fuel costs account for USD 0.171 per kWh of the distributed VOS value, while the utility-scale VOS value is USD 0.157 per kWh. This reflects the avoided cost that would have otherwise been generated at a centralized fossil fuel power plant. The current electricity system is heavily reliant on generation from fossil fuels (diesel), accounting for 87% of installed capacity, and more than 90% of electricity generation. This brings with it high fuel costs, that are partially mitigated through hedging, but still passed on to customers. High fuel prices and increased volatility of these prices illustrate the potential avoided costs the Cayman Islands could benefit from electricity generated from distributed and utility-scale solar, which are not dependent on fuel..

Another notable driver of the value of solar in the Cayman Islands is the impact of land use, which has a negative impact on the distributed and especially the utility VOS. Utility-scale solar has much greater local land requirements than distributed solar, and this is reflected in the Land Use variable, which accounts for the acquisition of land for developing utility-scale solar farms. For distributed solar, the assumption is that the systems will be rooftop mounted, therefore requiring no additional land on the Cayman Islands. However, utility-scale solar farms, with land requirements of around 3.5 acres per MW, require extensive amounts of land for development. High costs of limited land in the Cayman Islands, and the opportunity costs of competing land use interests result in a negative Land Use value of USD -0.017/kWh for the Utility VOS. This accounts for the roughly 190 acres of Crownland and 200 acres of waterways that could be used for floating solar farms, and which could be offered at a reduced rate. Given the challenges of land availability and high land costs in the Cayman Islands, the value of solar for land use can be lowered if innovative methods for developing utility-scale solar are deployed in the Cayman Islands. This would require the use of previously developed land, or deploying utility-scale systems on canopies, carports, or other facilities that would not require the use of additional land.

Overall, the Value of Solar (VOS) Study provides integral insight on the value and opportunity for developing solar power in the Cayman Islands, which can elevate the country towards achieving its envisioned clean goals future outlined in the National Energy Policy. The sixteen variables considered in the VOS study provide a comprehensive assessment of the overall value of distributed and utility-scale solar for the Cayman Islands. This study highlights clear opportunities for the country to harness its local resources to develop an electricity system that offers greater reliability, lower costs, and society-wide environmental and economic benefits for the country.

2. Value of Solar Study Overview

2.1. Background of Cayman Islands Power and Solar Sector

The Cayman Islands is a British overseas territory that encompasses three islands in the western Caribbean Sea, with a total area of nearly 102 square miles and a population of roughly 68,000 people. The country is comprised of three islands: Grand Cayman, Cayman Brac, and Little Cayman, and across most of the territory, electricity is provided by the electric utility, Caribbean Utilities Company, Ltd. (CUC). The company is primarily owned by the electric utility, Fortis Inc., through its wholly owned subsidiary, Fortis Energy (Bermuda) Ltd., with approximately 60 percent of shares, while private Cayman residents own about 15% of CUC's registered shares.[1] CUC is vertically integrated and responsible for the generation, transmission, distribution of electricity in Grand Cayman and sale of electricity to customers. Overall, the grid is highly reliable and well maintained, and CUC customers can expect rapid restoration of power in the event of an outage.

CUC provides power to its nearly 33,000 customers spread across residential, commercial and large commercial customer segments primarily with the deployment of diesel generators. The total installed capacity by resource type for 2022 is shown in Exhibit 4.

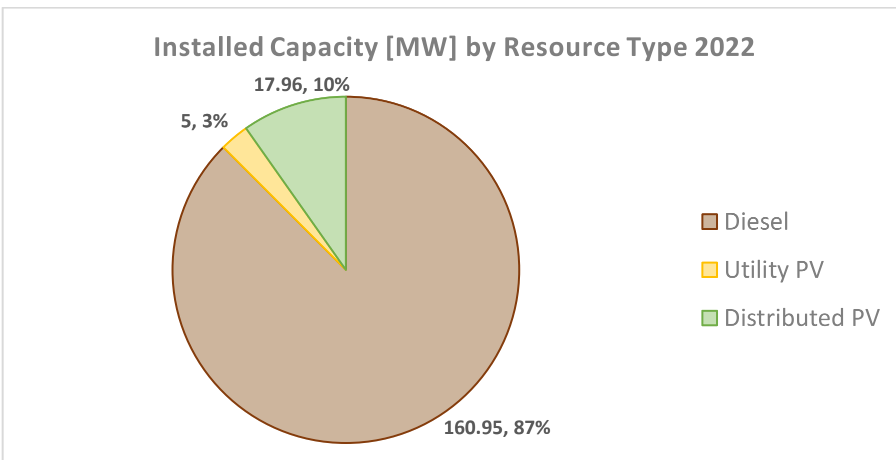

Exhibit 4: Installed Capacity by Resource Type for Cayman Islands in 2022.

As of 2022, 160.95 MW of the total 184 MW, or nearly 87%, of installed generation capacity are diesel generation assets. The only current utility-scale renewable generation asset in the Cayman Islands is a 5 MW solar farm in Bodden Town on Grand Cayman that began operation in 2017 and is owned and operated by BMR Energy. Construction is ongoing for the development of two 10 MW/10 MWh utility scale battery energy storage units which are expected to become operational in 2023. In addition to the utility-scale solar farm, there are also nearly 18 MW of distributed solar assets, contributing 33 GWh or 5% of the total island-wide electricity demand.

Since nearly all the electricity generated on the islands comes from diesel assets, the electricity system is vulnerable to the volatility of fuel prices, and overall, impacted by global events that directly affect the

[1] Caribbean Utilities Company, Ltd (CUC). 2021. "Shareholder and Corporate Information." https://www.cuc-cayman.com/investor-relations/shareholder-and-corporate-information/

supply chain of fuel. This in turn hinders energy security and resiliency in the nation and drives up electricity prices. The average electricity tariff from January 2014 to October 2022 in the Cayman Islands was US $0.307/kWh based on CUC data (see Exhibit 47), which falls only slightly below the Caribbean average of $0.33/kWh and includes fuel costs, duties, energy charges, etc.[2] The most recent Cayman residential rate as of October 2022 is US $0.447/kWh (see Exhibit 47). This higher rate is due to the ongoing Russia-Ukraine conflict and Organization of the Petroleum Exporting Countries (OPEC) supply curtailment that have led to higher fossil fuel prices. However, a 2021 anonymous survey undergone by CARILEC (Caribbean Electric Utility Services Corporation), revealed that Cayman prices remained competitive in the region. The results, displayed in Exhibit 5, show that the average monthly bill for a CUC customer consuming 800 kWh is US $251.33, which is 30% less than the average monthly bill for customers in similar sized jurisdictions. A comparative analysis of CUC cost against others in the region show that the lower CUC tariff is due to several factors including the successful fuel hedging practices at CUC and higher generation and transmission and distribution efficiencies.

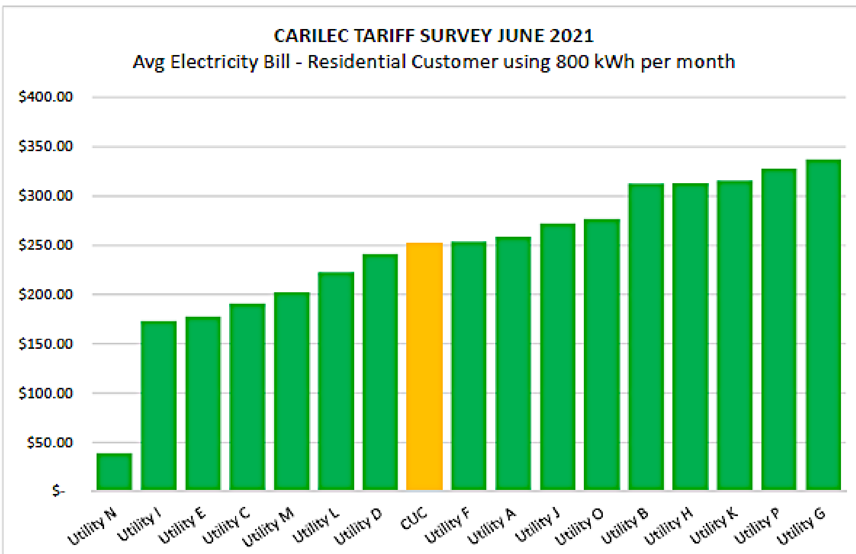

Exhibit 4: CARILEC tariff survey June 2021 for residential customer using 800 kWh/month in various locations. Source.[3]

Despite the Cayman Islands accounting for much less than 0.01% of global emissions, the high reliance on diesel fuel in the electricity sector leads to high local carbon emissions. Exhibit 6 shows the GHG emissions by sector in the Cayman Islands from 1990-2014, which has remained relatively constant since 2007 at around 720,000 tons of carbon dioxide equivalents. The results also show that the largest contributor to emissions is the energy sector, which is responsible for 65% of the total CO_2 emissions on average since 2007. The emissions from the energy sector are more than twice that of the transport sector, which is typically one of the highest emitting sectors in a country. This is very common in the region as most Caribbean nations are highly dependent on fossil fuel for electricity generation, with the energy sector on average responsible for 67% of total emissions among Caribbean islands in 2018.[4]

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[2] CUC billing rates shown in Exhibit 47: https://www.cuc-cayman.com/customer-service/billing-rates/; https://www.cuc-cayman.com/customer-service/fuel-cost/ and NREL's Energy Transition Initiative: https://www.energy.gov/eere/island-energy-snapshots; https://www.nrel.gov/docs/fy20osti/76662.pdf

[3] Cayman Islands Chamber of Commerce. 2021. "CUC's rates compare well with other utilities in the Caribbean". https://www.caymanchamber.ky/cucs-rates-compare-well-with-other-utilities-in-the-caribbean/

[4] USAID Data Services. 2021. "Greenhouse Gas Emissions in the Eastern and Southern Caribbean Region" Link

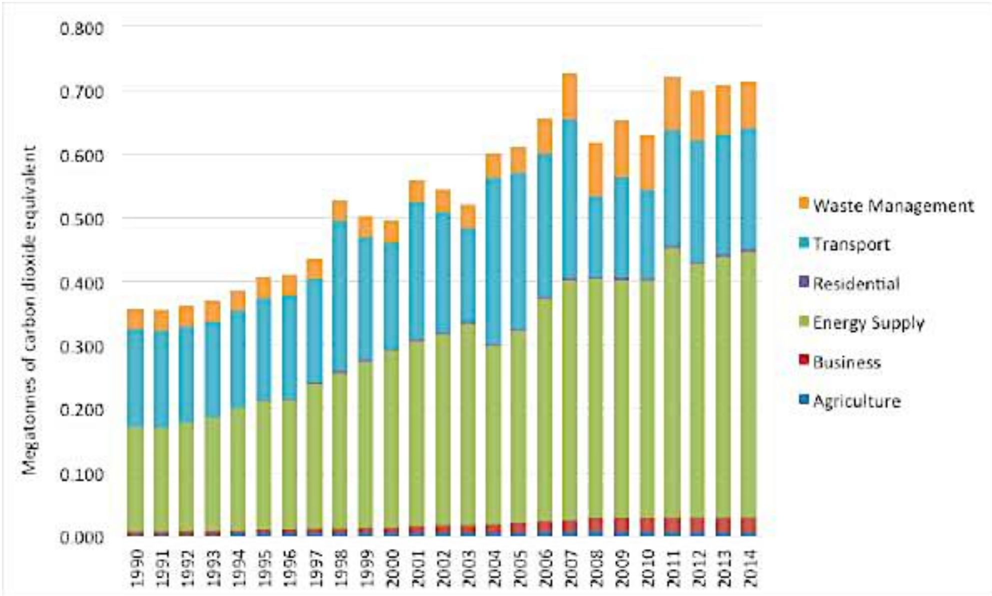

Exhibit 5: Cayman Greenhouse Gas emissions by sector (1990-2014). [Source](https://doe.ky/sustainable-development/carbon-footprint/).[5]

Although the nation is still entirely dependent on diesel generators for the majority of electricity generation today, the 2017-2037 National Energy Policy (NEP) and the 2017 Integrated Resource Plan (IRP) have set ambitious sustainability targets for the Cayman Islands. The long-term goal is to retire all diesel generators or convert them to dual-fuel use, thus transforming their power sector to a renewable and natural gas dominated grid in the next 10-15 years. CUC's aim is to have 25% of renewable energy on the grid by 2025 and 70% renewable energy electricity generation by 2037, in addition to meeting the objectives and targets of the Integrated Resource Plan and the National Energy Policy over the longer term. Some of the specific targets relating to the power sector and increasing renewable penetration are found in Exhibit 7.

[5] Cayman Island Government, Department of Environment. "Carbon Footprint." https://doe.ky/sustainable-development/carbon-footprint/

Overall Objective	Specific Objective	Progress
3.3.1. Ensure that the legal and regulatory framework promotes renewable energy development in pursuit of the NEP's renewable energy target and supports the longer-term goal to reach 100% renewable energy.	• Ensure that the benefits of renewable energy take into account the cost of energy to the jurisdiction	• 2017 IRP • VOS study
	• Ensure that the natural environment is protected	• Land assessment conducted by DOE, DOP, the energy policy coordinator and OfReg
	• Ensure fair competition for procuring utility scale sustainable generation	• OfReg approving renewable energy auction scheme • Utility-scale storage coming online by end of 2023 • OfReg confirmed allocation of 3MW of distributed generation to the CORE and DER programs
	• Increase penetration of renewable energy generation on the grid	• Battery will enable an additional 12 MW of distributed generation
3.3.2 Ensure that regulatory frameworks balance the interests of consumers in price, affordability and quality of service while facilitating investments, through competition, that optimize efficiency, reliability, safety, environmental performance and the security of the public electricity supply	• Ensure that investments in electricity infrastructure are supported by rigorous analysis on a basis of sound planning procedures	• CUC's Transmission & Distribution Licence • Cayman Brac Power and Lights Transmission & Distribution Licence • OfReg (ERA) Capital Investment Plan Rules, 2012
	• Lead a tariff setting process	• VOS study
	• Implement advanced metering	• Installed smart meters
3.3.3 Promote the utilization of brownfield sites such as marl-pits in the build-out of renewable energy facilities.	n/a	• 190 acres of man-modified Crown land have been identified as potentially suitable for utility scale solar, without the need for an Environmental Impact Assessment (EIA).

Exhibit 6: Selected NEP Objectives. Source.[6]

[6] Cayman Islands Government, Energy Policy Unit. "Energy Security – Electricity." https://www.energy.gov.ky/energy-security

2.2. Framing the need for the Value of Solar study

Consumers in the Cayman Islands have multiple energy programs to interconnect renewable energy systems to the utility grid. The Consumer Owned Renewable Energy (CORE) program was officially approved and established in 2009 and allows CUC to purchase electricity produced via customer-owned solar energy assets from approved customer applicants. The program operates under a net-billing arrangement in which customers sell all the excess CORE generated power to CUC at a contracted feed-in-tariff (FIT) rate for credit to their CUC account and purchase all the electricity they consume at their usual retail rates from CUC.[7] This enables consumers to reduce their electricity bills. The Distributed Energy Resource (DER) Program is another program to interconnect renewable energy systems to the utility grid, and it has been available to customers since 2018. In this program, participating customers self-consume energy they produce from their renewable energy systems, and in doing so avoid costs related to consumption and demand from the grid.[8] If there is excess renewable energy produced, DER customers can sell it to CUC at a rate equivalent to the avoided cost of generation. DER customers pay monthly fees to CUC based on demand charges, based on the customer's monthly peak demand and additional capacity, which is the highest peak demand recorded from the previous 24 months.

Despite efforts to employ renewable sources and the popularity of the CORE and DER programs, there have been many challenges regarding the uptake of distributed solar in the Cayman Islands. On the utility and regulation side, the challenge is mainly centered around grid capacity. Participation in consumer-owned, interconnected renewable energy system programs is dependent upon available hosting capacity on the grid. The Utility Regulation and Competition Office (OfReg) is responsible for approving any additional capacity for all renewable programs in the Cayman Islands. The capacity that was allocated to the CORE and DER Programs has been fully subscribed since January 2020, when the grid reached its projected variable renewable energy capacity. Additional capacity has been delayed pending the implementation of CUC's previously approved 20-megawatt (MW) Battery Energy Storage System (BESS). In September of 2022, CUC announced the signing of an agreement with Wärtsilä to procure a 20 MW/20 MWh Battery Storage Project.[9] CUC believes that this energy storage project will facilitate up to 29 MW of distributed customer-sited renewable energy resources without detrimental effects to its grid. This system is expected to provide power system optimization capabilities - from spinning reserve capacity to improved frequency response, to enhanced grid stability. OfReg states that it is currently considering allocating more capacity to accommodate more customer-owned distributed generation systems following the commissioning of the battery storage projects, but requires a more comprehensive understanding of the value of solar.

In addition to utility challenges, customers wanting to participate in the CORE and DER programs also face concerns. Many customer concerns originate from system costs, rate structures and perceived lack of necessity for the systems. Due to the high upfront investment required for a distributed solar system, certain socioeconomic groups are often excluded from participating in renewable energy programs. Some customers are concerned about the long payback period given the upfront costs to acquire the system, combined with declining FIT rates. From the customer perspective, the declining FIT rate associated with

[7] CUC. "Distributed Energy Resources (DER) Programme." https://www.cuc-cayman.com/renewables/core-programme/
[8] CUC. "Renewable Energy." https://www.cuc-cayman.com/renewable-energy/renewables/
[9] CUC. 2022. "CUC and Wärtsilä sign agreement for a 20 MW/20 MWh Battery Storage Project." https://www.cuc-cayman.com/fronthome/download_pdf?file=1664397056cuc_signs_agreement_for_battery_storage_project_280922.pdf

the CORE program, which was initially set at 37.0[10] KYD cents/kWh and now stands at 17.5 KYD cents/kWh, as well as an overall lack of clarity in the program rate structures, have decreased the incentive for the uptake of distributed solar. Additionally, with CUC maintaining a highly reliable grid, there is no real urgency from a consumer perspective to counteract power outages with a distributed solar PV and BESS system. Residential solar also raises questions of equity given that middle-upper income households have the least financial incentive to lower their electricity bills, but can afford to install residential solar systems and participate in CORE and DER programs. Contrarily, consumers from lower-middle income families have the largest incentive to lower their electricity bills but often cannot afford solar systems to participate in CORE and DER programs.

This Value of Solar (VOS) Study is a critical step towards helping the Cayman Islands attain the clean energy future envisioned in its National Energy Policy goals and to transition the power sector to a solar-dominated grid in an equitable and rapid manner. Current FIT rates may not be capturing the true value and costs that solar entails for the utility, economy, and society at large. Therefore, as part of developing a fair rate of compensation for this exported electricity, OfReg must determine an accurate and comprehensive reflection of the value of that exported energy. The VOS study will ensure that participants in the Cayman Islands renewable energy programs are compensated fairly for their investments without compromising the financial health of the utility and without unfairly affecting the electricity costs of non-participant ratepayers.

2.3. Defining the Value of Solar

A Value of Solar (VOS) Study is an analysis to quantify the net benefits of solar energy provided to the grid by utility customers (known as prosumers) or third parties who own solar PV systems. The implementation of distributed solar energy affects a wide variety of technical, economical, and societal factors such as utility fuel costs, job creation, and air quality due to reduced emissions. The methodology begins with quantifying the value of solar with respect to each of these factors using technical specifications, equipment lifetime costs, and other relevant data to calculate value of solar (VOS) variables. If the implementation of solar impacts a given factor in a positive way, the VOS variable for that factor will be positive (i.e., a net benefit). Conversely, if the implementation of solar affects the factor negatively, the VOS variable for that factor will be negative (i.e., a net cost). The overall sum of the VOS variables for each of the technical, economical, and societal factors considered gives the final Value of Solar. The output of this study is a monetary value per kWh of electricity provided to the grid by an interconnected solar system.

The outputs of the VOS Study will assist OfReg in developing a fair FIT rate of compensation for this exported electricity. The FIT refers to the rate at which CORE and DER participants in the renewable energy programs are compensated for the electricity they export to the grid. The VOS will be one component of a future Feed-in Tariff.

[10] CUC. 2010. "Caribbean Utilities Company, Ltd. 2010 Annual Report." https://www.cuc-cayman.com/reports/download_pdf?file=1305369078cuc2010ar.pdf

3. Stakeholder Perspectives on Value of Solar in the Cayman Islands

An initial and crucial step for the VOS study was to gain an understanding of various stakeholder opinions and stances regarding the uptake of solar in the Cayman Islands. The aim of the stakeholder engagement was to get insight into the variety of opinions on the impact of solar as related to the following areas:

- Environmental impacts
- Grid impacts
- Impacts on energy costs
- Economic impacts, including job creation

The engagement activities included surveys, discussions, and invitations to complete a matrix ranking the importance of various factors to the Value of Solar. These activities also provided opportunities for stakeholders to share their thoughts on any additional areas which they deemed to be pertinent to the national discussion on solar.

Stakeholder	Perspective	Factors Affecting Value
PV Customers	Want to have a predictable return on their renewable energy investment and be compensated for benefits the system provides.	Benefits include the reduction in the customer's utility bill and any incentive paid by the utility or other third parties. Costs include cost of the equipment and materials purchased (inc. tax & installation), ongoing O&M, removal costs, and the customer's time in arranging the installation.
Other Customers	Want reliable power at lowest cost.	Benefits include reduction in transmission, distribution, and generation, capacity costs, energy costs and grid support services. Costs include administrative costs, rebates/ incentives, and decreased utility revenue that is offset by increased rates.
The Utility	Want to serve customers reliably and safely at the lowest cost, provide shareholder value and meet regulatory requirements.	Benefits include reduction in transmission, distribution, and generation, capacity costs, energy costs and grid support services. Costs include administrative costs, rebates/ incentives, decreased revenue, integration & interconnection costs.
Society	Want improved air/water quality as well as an improved economy.	The sum of the benefits and costs to all stakeholder, plus any additional societal and environmental benefits or costs that accrue to society at large rather than any individual stakeholder.
Government and Policymakers	Want to ensure the objectives of the national energy policy (NEP) are successfully achieved, including developing an effective legal and regulatory framework to stimulate development of renewable energy with consideration for cost of energy, reliability, safety and for the environment.	Benefits include increase in economic growth, job creation, lower cost and improved environment associated with increased renewable energy development. Costs include reduced tax revenue from fuel.

Stakeholder	Perspective	Factors Affecting Value
Developers	Want to develop renewable energy projects in a fair environment, with limited restrictions on installation capacities or taxes/duties on equipment	Benefits include increase in economic output from the renewable energy sector. Costs include cost of labor, equipment, and materials for renewable energy projects (passed on to PV customers).
General Business Community	Want development of renewable energy to have positive run-on impacts in other sectors of the economy.	Benefits include increase in economic output from the renewable energy sector, and the societal and environmental benefits and costs accrued to society at-large

Exhibit 7: General perspectives of major stakeholder groups impacted by the uptake of solar PV

ENVIRONMENTAL IMPACTS

One of the most significant benefits of solar energy is its positive environmental impacts. Solar energy helps individuals and businesses reduce their carbon footprints, while reducing local air pollution. Furthermore, many communities are developing clean energy goals and strategies to meet climate change commitments through increased renewable energy use. Solar energy is one of the primary and most effective solutions to meet these targets. Consideration must also be given to the fact that large-scale solar installations require large areas of land, which is generally difficult to obtain in the island context, especially where there is a large dependency on land for tourism and biodiversity. End-of-life management of solar panels and associated equipment such as batteries is also an area for discussion.

GRID IMPACTS

A frequent concern about solar energy is the impact it may have on grid stability. New solar installations provide several benefits to the grid. They provide a new source of electricity that helps reduce the need for more capacity investment. With the right equipment, distributed solar can provide electricity to customers during grid outages caused by extreme weather events and other emergencies. On the other hand, without the implementation of support strategies (e.g., changes in generator dispatch or investment in storage) to smooth the intermittent electricity production, integration of solar can lead to voltage and frequency fluctuations and consequently, interruptions in the grid supply. In addition, siting new transmission lines, if necessary, can lead to complex regulatory hurdles and added costs, such as voltage regulation and grid edge management.

IMPACTS ON ENERGY COSTS

Solar energy adoption frequently leads to substantially lower energy costs for homes and businesses. However, some stakeholders perceive solar as an expensive energy option due to its relatively high upfront costs. Conversely, other stakeholders believe that counteracting the high fuel costs for the country make solar a very appealing energy resource. The cost advantages of solar will vary depending on local policies and economic conditions. Solar energy is more competitive in territories with higher energy costs, and where policy incentives have been adopted that encourage solar development. Nevertheless, solar energy is dramatically less expensive than even a few years ago. Governments can take many effective steps to make solar more competitive in their jurisdictions.

ECONOMIC IMPACTS

Economic impact mostly assesses the impact from employment and additional tax revenue generated from investing in solar, and the benefits it has to the local economy. Solar energy generates economic activity by attracting new businesses to a community and creating jobs. Solar energy development creates new jobs in installation, maintenance, project development, finance, and engineering, to name a few, as well as indirect jobs resulting from local economic stimulation. Some communities may also benefit from increased property tax revenue as a result of new solar installations, though the extent of these benefits will vary by location.[11]

3.1. Discussions with stakeholder groups

Discussions were held with the following Cayman stakeholders as part of the engagement activities:

- The Caribbean Utilities Company, Ltd. (CUC)
- The Cayman Contractors Association (CCA)
- The Cayman Energy Policy Council (EPC)
- The Cayman Islands Chamber of Commerce
- The Cayman Islands Department of the Environment, Environmental Unit (DOE)
- The Cayman Renewable Energy Association (CREA)
- The Department of Planning (DOP)
- The Ministry of Sustainability and Climate Resiliency (SCR)

Land availability featured prominently in the discussions as it is a limited resource in the territory and using it for solar farms incurs an opportunity cost as that land also has biodiversity and commercial value. It was noted that as land is increasingly used up for solar installations, land costs would also increase. Many stakeholders acknowledged that rooftops and carparks provide viable alternatives for solar installations and studies have been performed to determine the resource potential of such spaces in Grand Cayman.

In terms of environmental impacts, most stakeholders acknowledged that solar energy has the potential to avoid emissions and improve air quality. However, these factors did not seem to be very prominent in the discussions of the value of solar, possibly due to the already widespread knowledge of these benefits as well as the relatively low emissions produced by the Cayman Islands on the global scale. There was also some doubt as to whether these environmental impacts had a significant influence on the wider public's decision to invest in their own solar systems. Concern was also expressed for the end-of-life management of batteries used with solar, particularly the disposal, storage and handling of batteries at end-of-life. This concern may have some validity as it was noted that there has been an increase in the uptake of batteries in recent years, as owners of solar systems aim to reduce their electricity bills and increase their resilience in the face of interrupted grid supply.

With regard to reliability and resiliency, the stakeholders noted that the current electricity system is very reliable and hence the wider public probably take grid stability for granted. However, the RMI team was informed that Cayman is a financial services center and is therefore highly dependent on electricity and hence grid reliability, making a stable supply of paramount importance.

[11] Solsmart. "Solar Energy: "Solsmart's toolkit for local governments." https://solsmart.org/solar-energy-a-toolkit-for-local-governments/

Electricity costs were also ranked highly in terms of importance to the uptake of distributed solar. This factor was described as one of the major drivers for the uptake of solar as residents and businesses are interested in reducing their expenditure on electricity. However, this major incentive towards solar is balanced out by the installation costs as well as the connection process for distributed solar PV systems. It was pointed out that although commercial customers find the benefits of solar to be valuable, the bureaucracy of getting connected to the grid is discouraging and many often find it easier to simply pass on high electricity costs to the customer through increased prices for their goods and services.

Upfront costs were generally ranked of high importance in the uptake of solar as the high capital costs of a system pose a significant barrier. Stakeholders noted that financing options were available, however they often were not sufficient to make the investment affordable for residential customers. For commercial customers, however, it was revealed that costs were not as much of a problem affecting solar uptake compared to the limited distributed PV capacity limits on the Cayman electricity system. This issue featured heavily in stakeholder discussions as many cited the inconsistent release of capacity for new solar installations as a major concern affecting solar uptake because this caused uncertainty and volatility in the local solar industry. This volatility was also tied to points made about the impact of solar on the local economy. Many stakeholders acknowledged that the uptake of solar could incur the benefits of economic diversification and job creation while also working towards the National Energy Policy goal of development of a sustainable energy industry. However, the uncertainty around the release of capacity discourages both developers and customers from partaking in the sector, which slows down the industry. One question raised, for instance, was whether it was feasible to train a renewable energy workforce if there was no capacity available for future installations. Another issue with the release of capacity was that higher income residents and large businesses and developers were often the first to claim the capacity, leaving little available for the rest of the population.

This leads to the topic of equity, which was raised often in the discussions. It was recognized that not all residents on Cayman have the same access to solar. An example was provided of a situation where a tenant of an apartment building would need to obtain approval from all of the other tenants if they wanted to install solar. Community solar was hence mentioned as one option for providing equitable access to solar investments. The rate structure in terms of both charges and credits was also brought up as a factor in equity concerns. One suggestion was that solar exported to the grid could be credited at lower rates for larger systems and higher rates for smaller systems, while maintaining the same payback period for both types of systems. Another thought provided on rate structures was that they should consider the difference in value between solar produced and consumed onsite versus solar exported to the grid. Finally, in one instance, it was highlighted that there were residents in Cayman who were hesitant to install solar for fear of burdening other customers who did not have solar due to the current tariff structure. This led to the discussion of a need for greater public education on the utility's rate structures and distributed generation programs.

Other factors discussed included the potential for income generation and the impact of solar uptake on utility cashflows. It was mentioned that lower income owners could probably benefit from income generated from selling solar to the grid, however this was not brought up by many stakeholders. Similarly, not many stakeholders discussed the impact of increased solar uptake affecting utility cashflows, but it was noted that there are some residents who would be happy to no longer have to pay the utility for electricity. On the other hand, the RMI team was informed that it was fairly simple to become a shareholder in the utility company, and therefore those persons would probably have some concerns about a decrease in utility revenue. Another concern raised about the uptake of rooftop solar was the potential for it to displace cheaper forms of solar at higher penetrations which could lead to curtailment of the lower cost energy based on the details of power purchase agreements.

In general, stakeholder discussions and surveys revealed that many consider the positive outcomes of solar uptake to include:

1. Reduced emissions;
2. Value added to the economy;
3. Job creation;
4. Reduced reliance on electricity generated by CUC using fossil fuels/ reduced reliance on imported fuel supply;
5. Diversification of energy sources in the electricity sector;
6. Reduced electricity bills;
7. Better ability to meet long-term energy needs in the Cayman Islands;
8. Less volatility in the energy market.

However, there are also perceived negative outcomes related to:

1. Possibility of grid defection;
2. Impact of solar affecting grid stability, particularly if accompanying battery storage capacity is inadequate;
3. High cost of land and limited land availability for developing solar relative to competing uses for the same land;
4. Higher electricity costs if too many people defect from the grid, or if uptake is not handled in a judicious manner;
5. Job displacement and the need for re-educating the workforce as solar displaces fossil fuels;
6. Possibility of rooftop solar displacing cheaper sources of solar

Other major talking points were focused on equity (in terms of access to solar installations), as well as the limited distributed solar capacity and rate structures. Finally, stakeholders expressed a need for increased public awareness on the relationship between renewable energy and energy efficiency as well as further education on the utility's various distributed energy resource programs.

3.2. Stakeholder Surveys

Surveys were conducted to measure stakeholders' perspectives on the relative importance of VOS variables to the uptake of solar PV in the Cayman Islands. Respondents were asked to highlight their opinions on the positive and negative outcomes on the use of solar PV in the Cayman Islands, and to rank each VOS variable on a scale of 1 – 10, where 10 represented a variable of greatest importance to the Cayman Islands, and 1 related to a variable of least importance. For each VOS variable, a weighted average score was then calculated to determine the average importance of that variable out of 10. These values were then weighted again to provide a percentage score for each variable out of 100%. The results from the survey were then combined with results from the VOS matrix to produce an overall VOS stakeholder score, as shown in Exhibit 9.

A matrix was developed to allow stakeholders to rate the importance of various components of the VOS. The average rating was then used to weight the different variables in the final determination of the value. Overall, survey responses were obtained from OfReg, CUC, and members of the Cayman Contractors Association (CCA). The results from the survey and matrix are highlighted in Exhibit 9.

The variable of greatest importance to stakeholders was the avoided carbon emissions from increased solar uptake in the Cayman Islands, receiving a score of 8.64 out of 10. This was closely followed by the avoided energy and other air pollutants variables, which received scores of 8.62 and 8.58 out of 10.
Overall, six out of the sixteen variables received a score greater than 8 out of 10, indicating that stakeholders consider them to have the greatest impact on the value of solar in the Cayman Islands – Avoided energy, fuel price volatility, ancillary services, carbon emissions, other air pollutants, and ecosystem impacts (land impact variable 1). By contrast, the lowest scoring variables were transmission capacity value (5.41) and land availability (5.55), indicating that stakeholders consider these to have the least impact on the value of solar in the Cayman Islands.

No.	Variable	Weighted Average Variable Score (x out of 10)	Variable Percentage Value (%)
1	Net avoided energy value	8.62	7.41%
2	System Losses Value	5.88	5.05%
3	Fuel price volatility value	8.35	7.17%
4	Net generation capacity value	7.50	6.44%
5	Transmission capacity value	5.41	4.65%
6	Distribution capacity value	6.19	5.32%
7	Ancillary services value	8.18	7.03%
8	Reliability and resiliency risk value	7.60	6.53%
9	Market price response value	7.76	6.66%
10	Net carbon emissions value	8.64	7.43%
11	Other air pollutants value	8.58	7.37%
12	Net water impact value	5.98	5.14%
13	Net land impact value 1 (Ecosystem impacts)	8.34	7.17%
14	Land impact value 2 (impact on land values)	5.55	4.77%
15	Net economic development value	7.01	6.02%
16	Integration Costs	6.82	5.86%
	Total	**116.39**	100.00%

Exhibit 8: Results of stakeholder surveys and VOS matrix

4. VOS Methodology: Forecasts and Inputs

4.1. Forecasts

As part of the VOS study, several forecasts were generated to align on the future evolution of the power sector. Particularly, the RMI team performed a demand forecast to project future electricity generation and peak demand out to 2052 and created a simulated solar PV fleet that determined solar capacities and generation coming online each year. The following two sections review the forecasts in depth.

4.1.1. Simulated Solar PV Fleet

A key first step in calculating the value of solar was to forecast how much solar capacity was going to come online each year for the entire study horizon (2022 – 2052) and how much electricity would be generated from the solar capacity each year, taking into account panel degradation. The team generated these forecasts based on the 2017 IRP preferred plan, presented in Exhibit 10, which developed projections for the period 2017 – 2045. The expansion plan capacity from the 2017 IRP was slightly modified to reflect the current system of 2022.

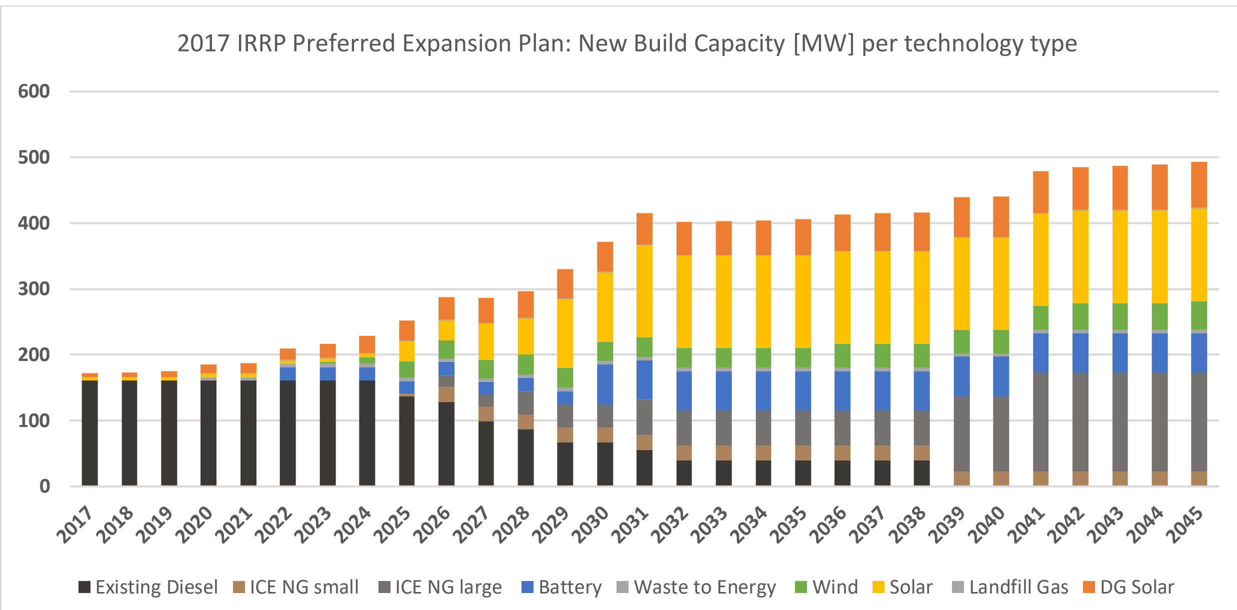

Exhibit 9: Modified preferred expansion plan for the Cayman Islands. Source: 2017 IRP

The overall goal for simulating the solar PV fleet was to stick to this expansion plan. The predicted 2052 installed capacity by resource type is shown in Exhibit 11. Comparing this with the 2022 installed capacity in Exhibit 4, it is clear that the power system in the Cayman Islands is expected to undergo a large transition and that solar and natural gas play key roles in the future electricity sector.

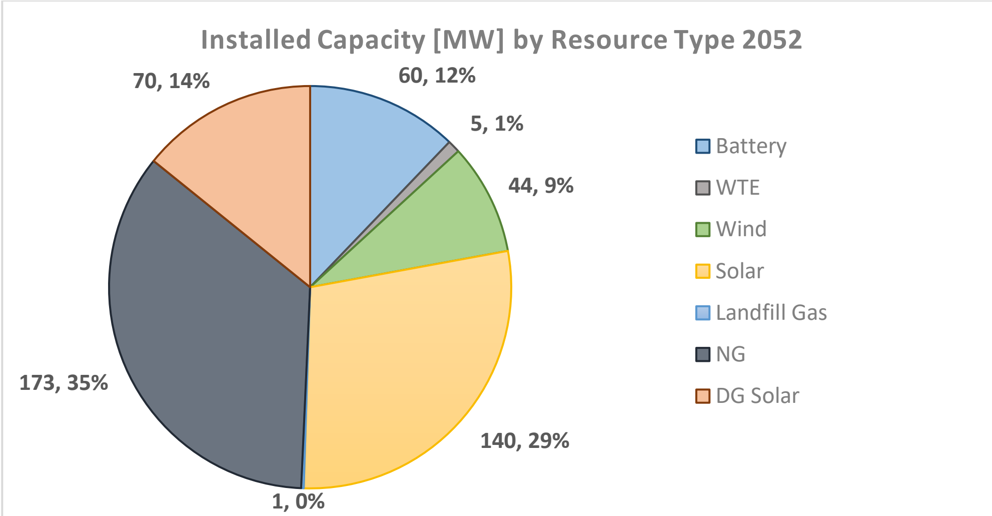

Exhibit 10: Installed Capacity by Resource Type for Cayman Islands in 2052.

According to the preferred expansion plan, distributed solar capacity and utility scale solar capacity reach 70 MW and 140 MW, respectively, by 2052 which account for a combined 43% of installed capacity in 2052. The team used these assumptions to design and simulate a distributed solar fleet and a utility scale solar fleet, which are separated and explained below.

Distributed Fleet:

Current distributed solar capacity was provided by CUC and is estimated to be roughly 17.96 MW. The IRP goal was to reach 70 MW in the next 30 years. Therefore, the RMI team set 70 MW to be the 2052 distributed solar capacity goal. Given that the combined 20 MW/ 20 MWh of battery storage is expected to begin operation by the end of 2023 and increase grid capacity levels, the team assumed that over the next few years there would be a large push for distributed solar. Therefore, roughly 3.8 MW of distributed solar was assumed to come online in 2023, 2024, and 2025, and for each year after, 1.5 MW is assumed to come online annually, in line with the 2017 IRP.

A simulated distributed fleet was generated based on these new annual capacity assumptions wherein new systems of varying sizes were added to the fleet until the total annual capacity was reached for a given year. Each new system was given a random selection of the most important characteristics such as capacity, tilt angle, azimuth, amount of system losses, location, etc. The values for each characteristic were limited within a reasonable range for the Cayman Islands context. The range of available characteristics for each system was as follows:

- Location [latitude, longitude] ~50 various locations around the Cayman Islands
- Fixed roof-mounted
- Capacity [kW] - 1-30 (skewed left- with an average of 6.9 kW, a max of 28.6kW and a min of 1 kW)
- Tilts [degrees] - 15-22 (normal distribution- with an average of 18.9, a max of 24.3 and a min of 15

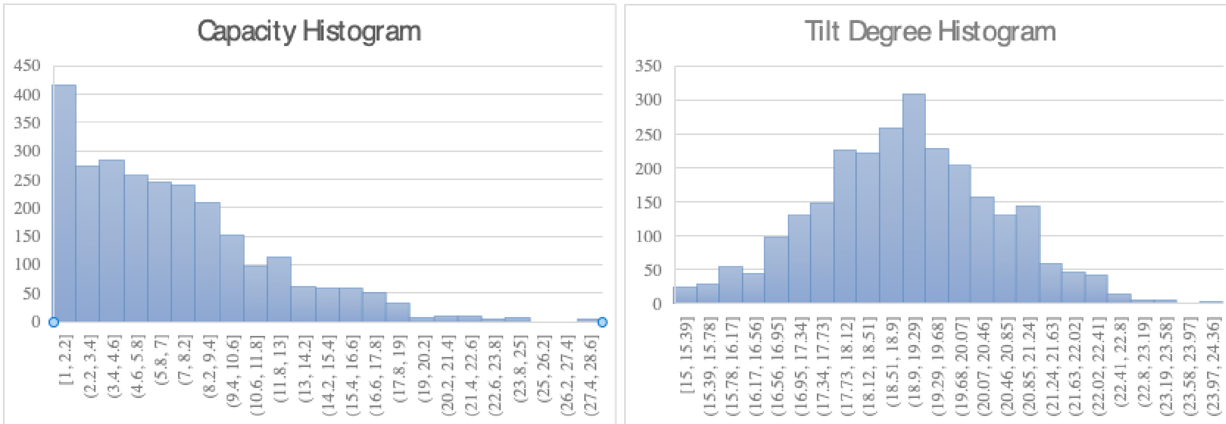

Exhibit 11: Capacity -MW [left] and tilt angle [degrees] [right] histograms for simulated distributed solar fleet.

- Azimuths [degrees] - 90-270 (normal distribution- with an average of 170.1, a max of 268.4 and a min of 94.7)
- Total system losses [%] = 10-20 (normal distribution- with an average of 13.6%, a max of 18% and a min of 10%)

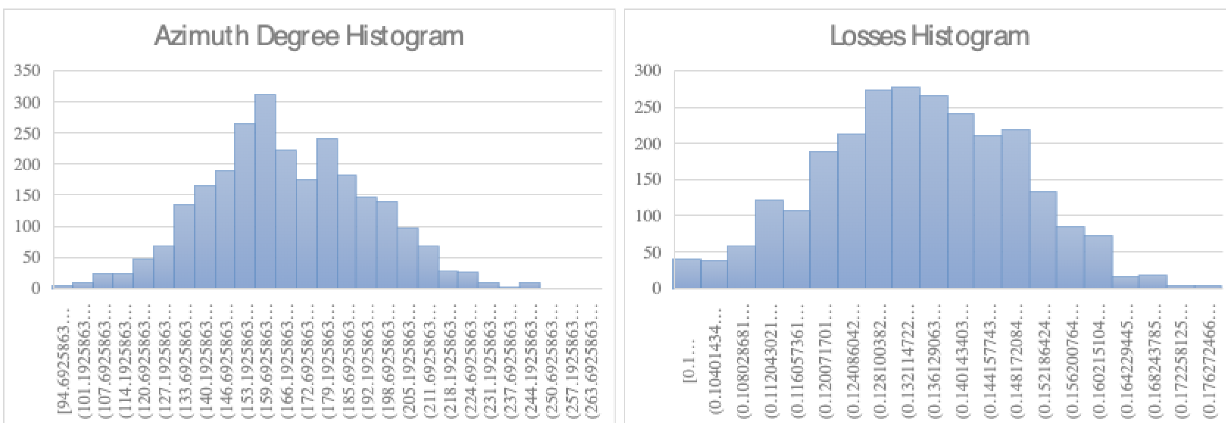

Exhibit 12: Azimuth [degrees] [left] and system losses [%] [right] histograms for simulated distributed solar fleet.

Once the fleet was determined for a year, each system was sent into NREL's PV Watts tool, which determines the hourly PV production for that year for a system of a given size and at a given location. The tool also takes inputs such as the tilt angle, azimuth angle, and total system losses. This methodology allowed the team to generate the hourly solar production for the new systems coming online each year. Additionally, a solar panel degradation factor of 0.5% per year was used for the existing fleet when projecting future production each year. The outputs of the analysis were a yearly distributed solar capacity and electricity production for a 30-year period, and these values were used for the entirety of the VOS study.

Utility Fleet:

The utility fleet was designed and simulated in a similar fashion to the DSG. The largest difference was the annual capacity assumptions, which were aligned with the new build utility scale solar capacity in the preferred expansion plan of the 2017 IRP. The new build annual capacities are as follows:

Year	New-Build Solar Capacity [MW]
2025	25
2027	25
2029	50
2031	35

Exhibit 13: New-build utility scale solar for the Cayman Islands. Source: 2017 IRP

Based on these annual new-build assumptions, the utility scale solar fleet was built but with a slightly different range of values for the important characteristics:

- Locations were based on the Cayman Islands DOE solar array feasibility study.
- Capacity [MW] - 0.5-30 per system
- All else was kept the same

Again, once the utility fleet was determined for a year, each system was sent into NREL's PV Watts tool to determine the hourly PV production for the new utility systems coming online each year. For each subsequent year, a solar panel degradation factor of 0.5% per year was used for the existing fleet when projecting future production. The outputs of the analysis were a yearly distributed utility capacity and electricity production for a 30-year period, and these values were used for the entirety of the VOS study.

4.1.2. Demand and Generation Forecast

An electricity demand forecast was conducted for the Cayman Islands to estimate future electricity customer numbers, electricity consumption in megawatt-hours (MWh), corresponding electricity generation (MWh) and peak demand in megawatts (MW). The electricity demand forecast was developed for the period 2022 to 2052 and estimated the primary requirements (in addition to required spinning and non-spinning reserves) that needed to be met by supply options.

For each customer class, historical consumer and consumption data were collected from CUC, and this data formed the baseline for determining an initial prediction for future demand in the Cayman Islands. In parallel, population and GDP data was collected from databases and the Cayman Islands statistical department, and future values were calculated based on baseline population growth and GDP growth forecasts. The initial demand forecast was then achieved by determining how elastic historical consumer numbers and electricity consumption were to historical growth in population and GDP, respectively. These elasticities were then used with the future forecasted population and GDP numbers to determine future electricity data. The initial projected consumption numbers were adjusted for increasing annual temperatures and seasonal monthly values. This gave an overall monthly modified kWh sales value (i.e. total consumption before accounting for non-technical losses or use of electricity by the utility).

Historical load factors and non-technical losses were calculated from data provided by CUC and applied to the modified consumption to determine the required future electricity generation (MWh) and the peak demand (MW). Load factor and non-technical losses were assumed to follow similar trends in the future. Both pre-COVID 19 consumption data and COVID 19 consumption data were included in the analysis and used to forecast future consumption and demand, meaning that future values take into account major recent events and are not over-estimated. After the analysis, there were two finalized forecasts – a projection for both electricity generation and peak demand. These final projections were used as key inputs for VOS study.

Annual electricity consumption is projected to grow by 60 percent over 30 years, from 765 GWh in 2022 to 1,218 GWh in 2052. Peak demand projections for 2052 are 163 MW, a 48 percent increase relative to the historical peak demand of 110 MW in 2022. Exhibits 15 and 16 show the results of the demand forecast for the Cayman Islands. These values are in line with the projections provided in the 2017 IRP.

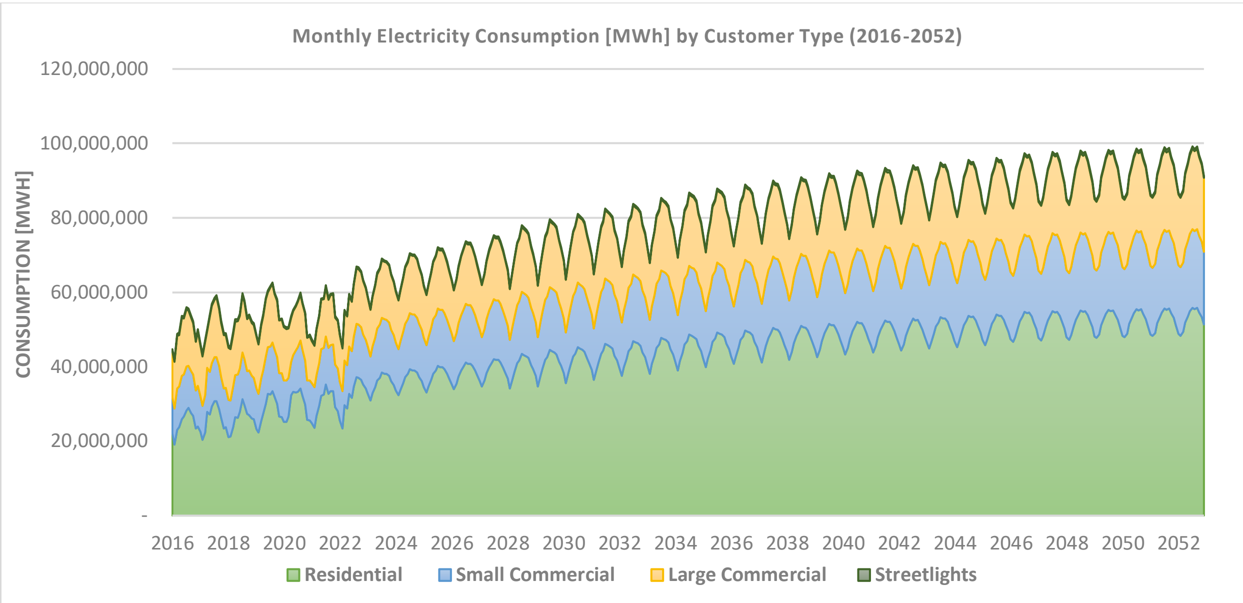

Exhibit 14: Monthly Electricity Consumption by customer type [MWh] from 2016 to 2052

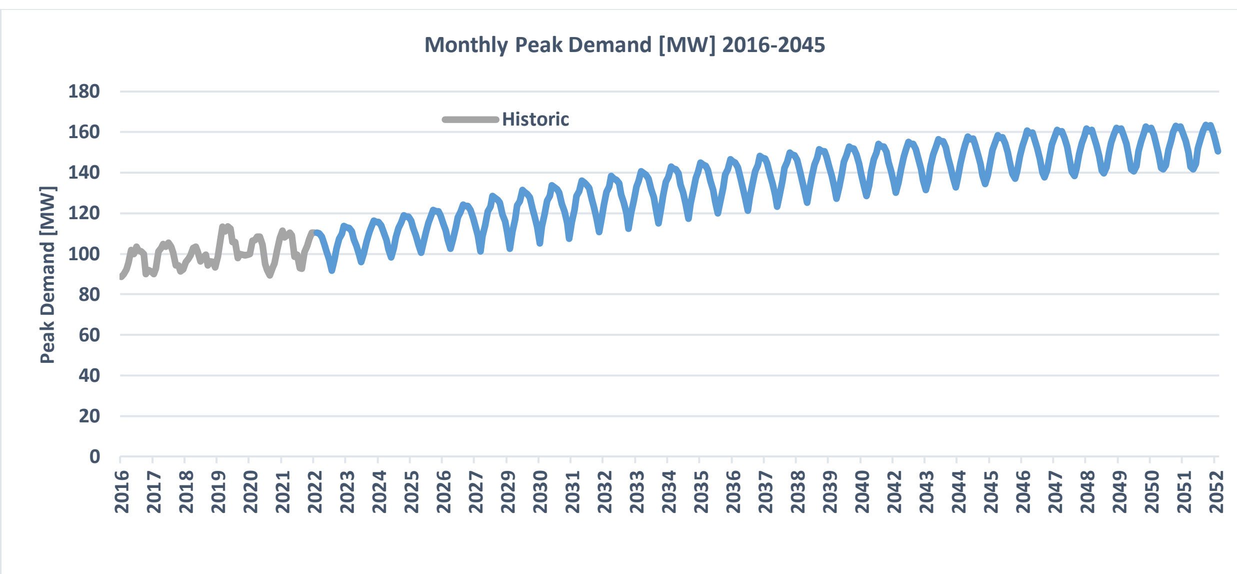

Exhibit 15: Monthly peak demand [MW] from 2016 to 2052

The fluctuating shape of the forecasts in the above projections is a result of the differences in monthly consumption due to seasonal trends. However, Exhibit 17 and 18 have been included to show the smoothed, annual electricity generation and peak demand.

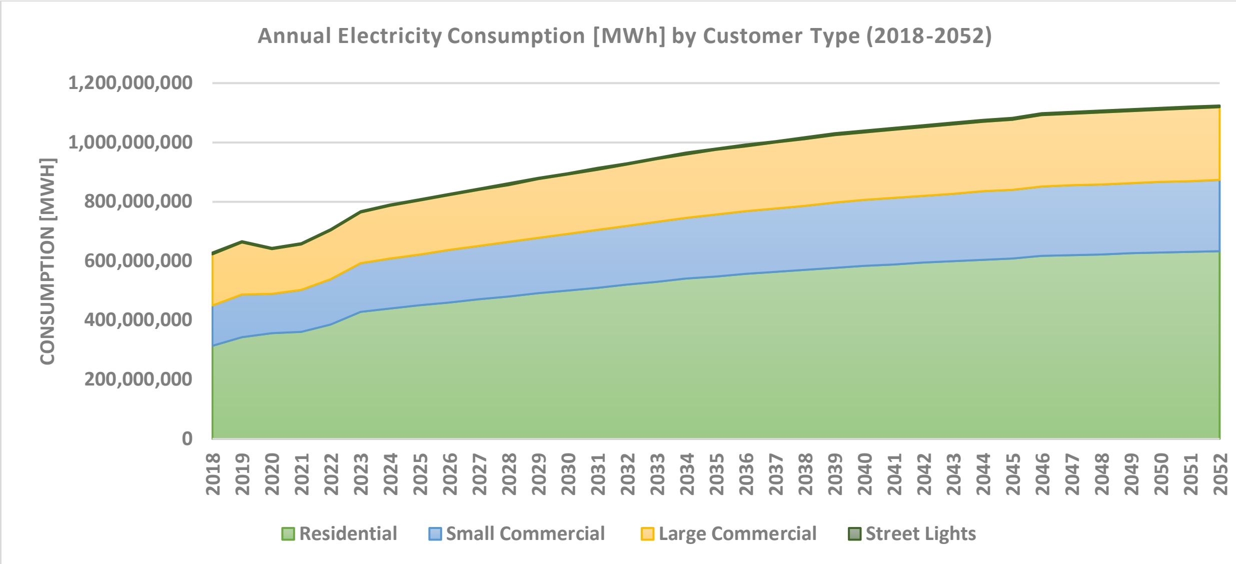

Exhibit 16: Annual Electricity Consumption by customer type [MWh] from 2018 to 2052

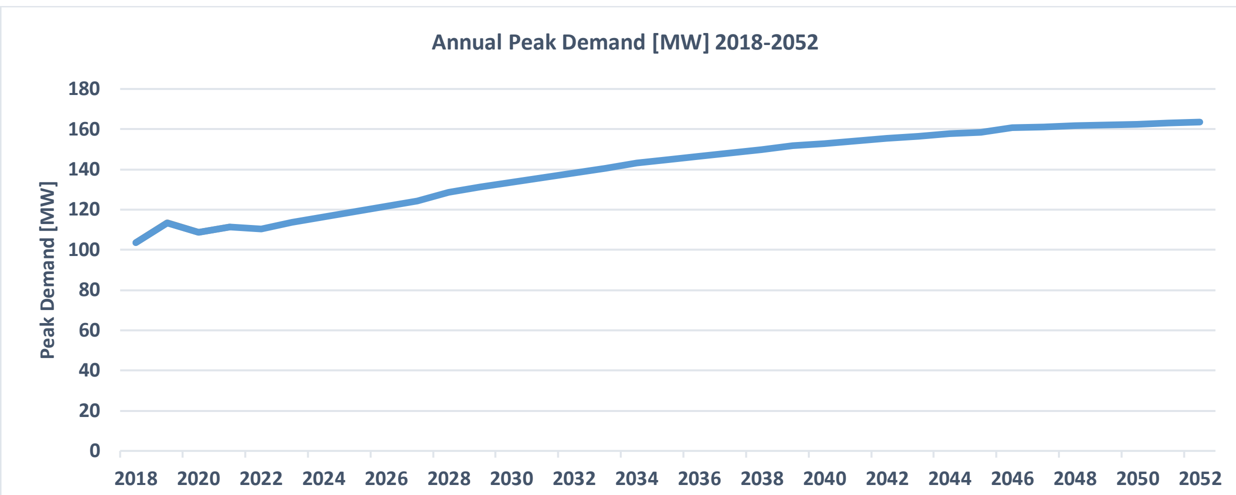

Exhibit 17: Annual Peak Demand by customer type [MW] from 2018 to 2052

4.2. Inputs

In addition to the key forecasts, further inputs were required to perform a robust VOS analysis. Inputs were acquired directly from stakeholders in the form of a data request, from well-trusted databases such as the Energy Information Administration (EIA) and the National Renewable Energy Lab (NREL), or from comprehensive literature reviews. Where specific data was not readily available, the RMI team used educated assumptions or methodologies based on the previous experience of the RMI team in the region. The following sections outline the key inputs that were used for the VOS study, provide the sources that were used and, if applicable, indicate any assumptions that were made.

4.2.1. Major Inputs and Assumptions

Several major inputs and assumptions were used throughout the analysis. They can be categorized into the following sections:

- Economic Inputs
- Tariff Data
- Solar Data
- Grid Data

Economic Inputs

The following parameters were obtained by calculating the historical 5-year average (except where indicated) average in the Cayman Islands:

Weighted Average Cost of Capital (WACC)	7.8 %
Return on Rate Base (RORB)*	6.95 %
Inflation Rate	3.0 %
Discount Rate	3.56 %

** Historical 4-year average used*

Exhibit 18: Economic input assumptions for the VOS study

For environmental and social analyses, a real environmental discount rate of 3.5% was obtained from the UK Green Book data tables. This was adjusted using the Cayman average inflation rate of 3% to give a nominal environmental discount rate of 6.6%, which was used in further calculations. Further, an exchange rate of 1 USD to 1.2 KYD was used in the analysis.

Tariff Data

CUC Tariff Data was taken directly from the CUC website and from data provided in the data request. From this data, residential, commercial, and large commercial base rates of electricity in KYD per kWh were determined and projected into the future for the analysis period. From these forecasts, an average weighted base rate of electricity was determined. In addition to the direct electricity rates, a risk-free bond rate of 3.5% was used and the RMI team calculated an average commercial value added per kWh of 0.0151 USD/kWh and the household electricity-depending leisure value of 0.0158/kWh, described in the Reliability and Resiliency variable methodology.

Solar Data

Apart from the simulated distribution and utility-scale solar fleets (capacities and production) that were used for the analysis, there were several other major assumptions regarding distributed solar. The following table summarizes the key ones:

2022 Installed Cost of Residential Solar [KYD/W]	**$3.25**
2022 Installed Cost of Commercial Solar [KYD/W]	$2.25
Solar PV annual degradation rate [%]	0.5
Inverter Efficiency [%]	95
Design Loss Factor [%]	85
BESS Installed Cost [USD/MW]	$1,934,720
Interconnection Fee [KYD]	$250
CORE FIT 0-5 kW [KYD/kWh]	$0.1750
CORE FIT 5-10 kW [KYD/kWh]	$0.15
CORE FIT 0-100 kW public [KYD/kWh] (NHDT Only)	$0.28 (NHDT Only)
CORE FIT 0-100 kW public [KYD/kWh] (Public Sector Only)	$0.21 (Public Sector Only)
DER RE PPA [KYD/kWh]	$0.15

Exhibit 19: Summary of solar-specific input assumptions for the VOS study

General and Administrative costs were also found in annual CUC reports.

Grid Data

The most important grid inputs were the single line diagrams, CUC generator information, substation information and feeder information provided as part of the data request. How these inputs were used is described later in the methodology. Additionally, a reserve planning margin of 45% was used in the analysis.

4.2.2. System Losses

System loss data was provided by CUC on a monthly basis for three types of losses between January 2018 and July 2022:

1. Plant Use (auxiliary use)
2. Generation (station losses)
3. T&D

For each type of loss and for each month between January 2018 and July 2022, the RMI team calculated the kWh loss percentage in comparison to the total kWh generation for that same month. Then these loss percentages were averaged over the entire period to determine an overall loss percentage for each of the three types of system losses. These three average loss percentages were used for subsequent years to create system loss projections from the generation forecast.

4.2.3. Fuel Price Data

Historical fuel price data in USD per imperial gallon was provided by CUC on a monthly basis between January 2016 and July 2022. Future diesel fuel prices were taken from EIA Annual Energy Outlook and the New York Harbor Ultra-Low Sulfur No 2 Diesel Spot Price in USD per gallon. The projections were made on an annual basis and were compared with historical CUC annual prices. The projected diesel fuel prices aligned with 2017 IRP values.

Future natural gas prices in USD per MMBtu were also taken from the EIA Annual Energy Outlook and compared against the values used in the 2017 IRP. The EIA projected prices were significantly lower than the 2017 values and that is because the Cayman Islands experience several cost adders that would apply to the acquisition of NG, considering that the infrastructure is not currently in place. The adders, taken directly from the 2017 IRP, are estimated as follows:

1. Storage, regasification, and transport = 2.28 USD/MMBtu
2. Shipping = 2.56 USD/MMBtu
3. Liquefication = 3.11 USD/MMBtu
4. Government Duty = 2.17 USD/MMBtu

Thus, the total cost adders when acquiring NG fuel in the Cayman Islands is 10.12 USD/MMBtu. This cost adder was added to the EIA projected natural gas spot price.

4.2.4. Fuel Hedge Data

Inputs related to fuel hedging were provided directly from CUC. Specifically, CUC uses call option premiums to hedge against volatile fuel prices in the future and historical fuel amounts and corresponding premium amounts were provided from June of 2022 to May of 2023. The RMI team calculated the average premium cost to be USD 6,888 during this time. Future fuel hedge prices were assumed to increase at the same rate as future fuel prices.

4.2.5. Capital Expenditures

For the avoided transmission and distribution capacity, the RMI team used the historical capital expenditures from CUC's annual report to determine the spending trends for generation, transmission, and distribution from 2006 through 2021.

The RMI team analyzed historical spending trends to forecast how future spending would be divided among transmission, distribution, and generation. For generation, the average percentage of the total expenditure was around 53% and it oscillated between ~40% and ~70% approximately every 5 years. For transmission, the average percentage of the total expenditure was around 10% and had larger fluctuations from 0.5% to ~30% close to every 10 years. For distribution, the average percentage of the total expenditure was around 37% and there were very consistent but small fluctuations approximately every 6 years between 15% and 55% were observed. These trends were used to predict future percentages for spending amongst the three categories.

In addition to the spending trends between the three categories, total capital expenditure was linearly projected to increase based on data the from 2006 to 2021. An average annual increase of 1,762 thousand dollars was predicted. (A multi-linear regression was attempted based on peak demand and other variables but did not outperform the simple linear regression). Exhibit 21 shows the historical (grey) and projected (orange) total capital expenditure.

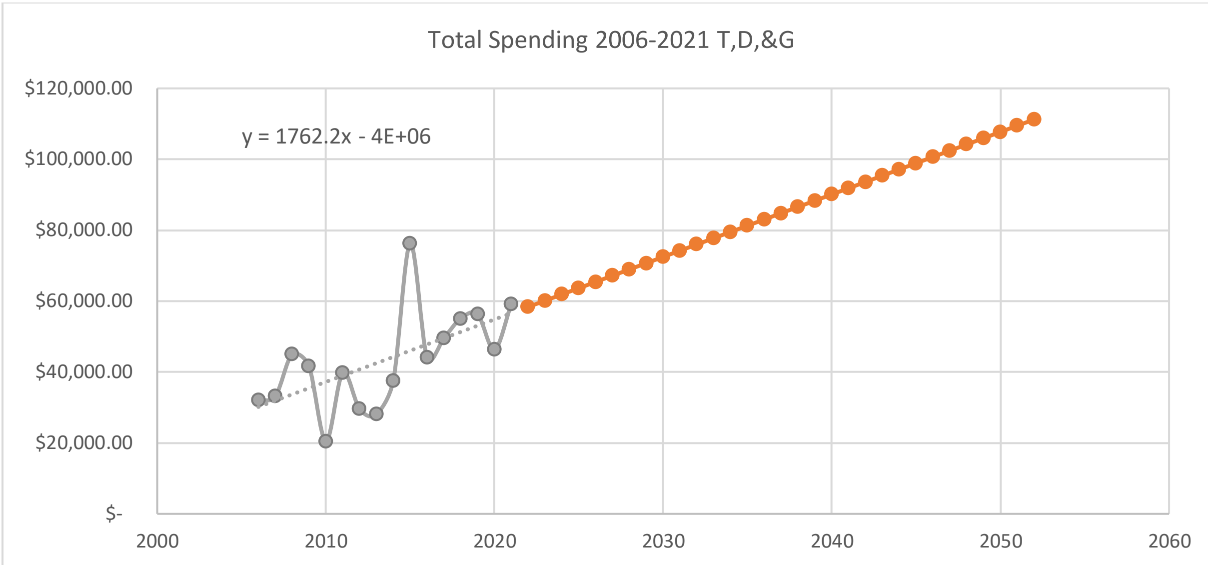

Exhibit 20: Historical (grey) and projected (orange) total capital expenditure.

At this point the team had a 30-year forecast for the overall spending and, the identified trends that needed to be followed in terms of generation versus distribution versus capacity spending. The team created the individual forecasts for the three categories by maintaining the overall trend in fluctuations and ensuring that each category's spending aligned with an individual linear projected spending for that category, separate from the linear projection of the overall spending.

As an example, Exhibit 22 shows the historical (grey) and projected (orange) total distribution expenditure. The grey dashed trend line is the linear projection for future distribution spending based solely on historical distribution spending. The orange projected data was created by applying the distribution spending trends, i.e. fluctuations between 15% to 30% of total expenditure every 6 years, to the linearly projected total capital expenditure in Exhibit 19. The projected data was created to ensure that it aligned with the linear projection for future distribution spending, which can be seen since the orange trendline of the predicted data mimics the grey trendline of historical data.

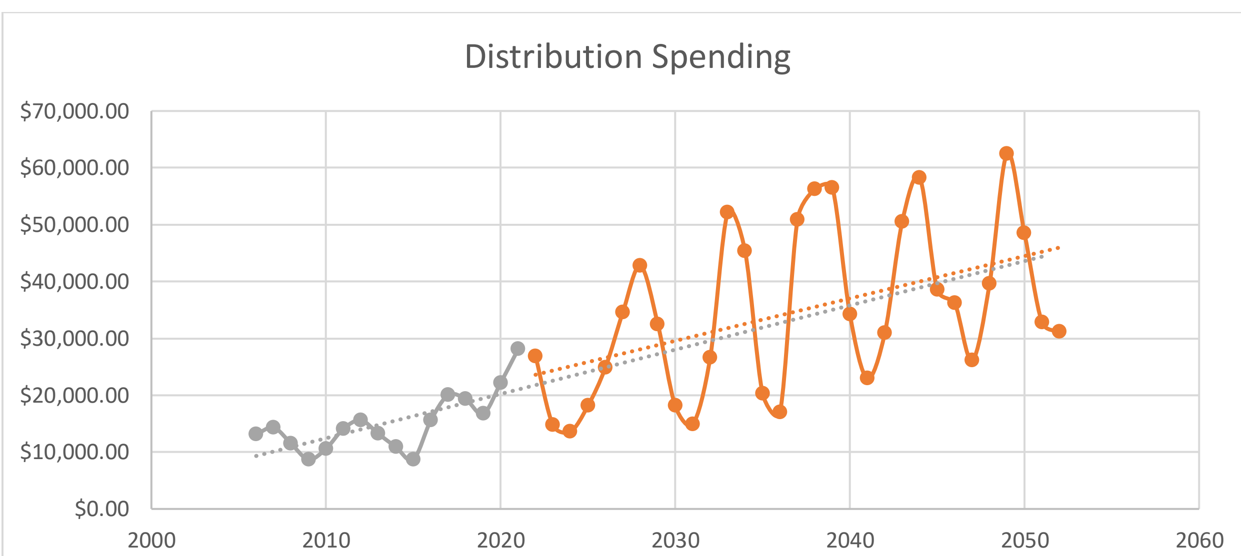

Exhibit 21: historical (grey) and projected (orange) total distribution expenditure.

The same process was applied to the transmission spending, with results shown in Exhibit 23.

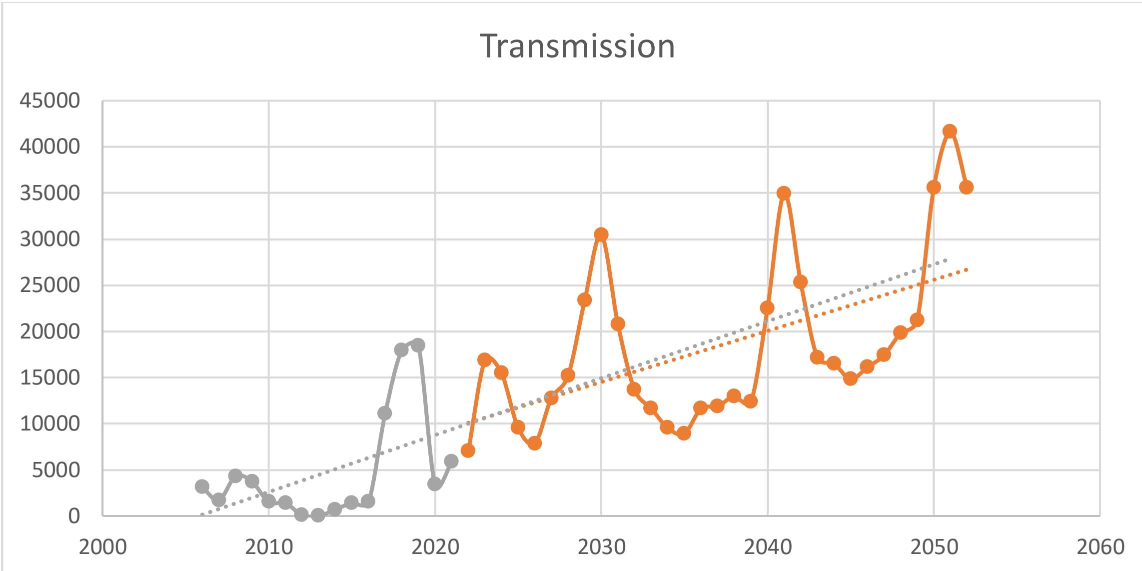

Exhibit 22: Historical (grey) and projected (orange) total transmission expenditure.

Finally, the process was applied to the generation spending, with results shown in Exhibit 24. The graph also shows the added capacity of CUC generator sets (based on commissioning data) to validate the historical peaks in spending and to add a bit more context. For example, the large generation expenditure in 2015 was due to 39.6 MW of capacity coming online in 2016.

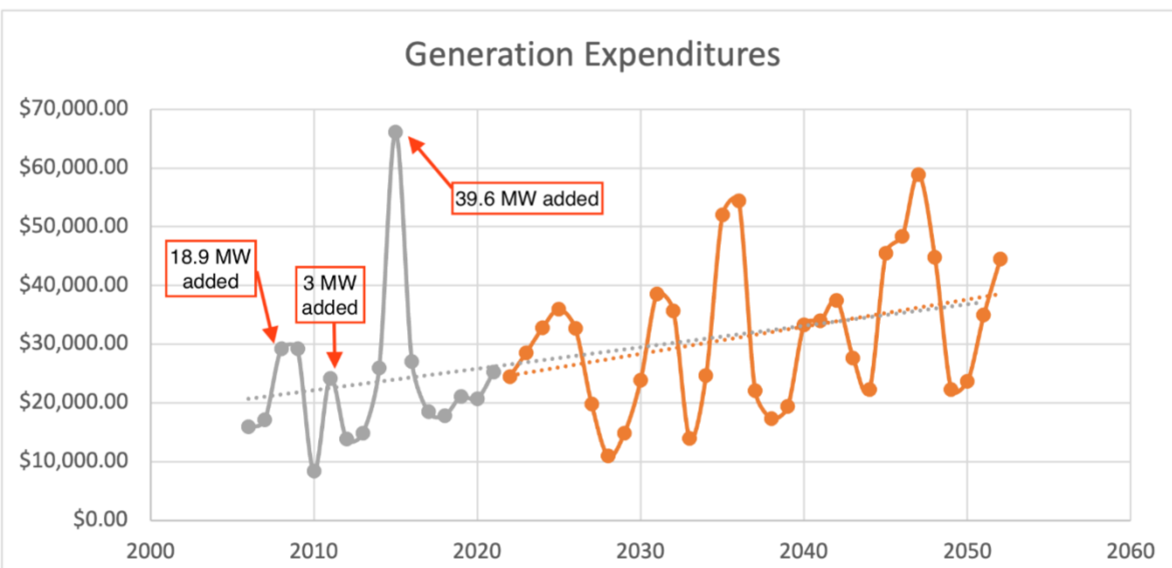

Exhibit 23: Historical (grey) and projected (orange) total generation expenditure

The final results were transmission, generation and distribution spending forecasted out for the next 30 years.

4.2.6. Environmental Data

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions factors for natural gas and diesel were obtained from U.S. Environmental Protection Agency (EPA) data tables for 2022[12]:

	CO_2 (kg/MMBtu)	CH_4 (kgCO_2e/MMBtu)	N_2O (kgCO_2e/MMBtu)
Diesel	73.96	0.075	0.1788
Natural Gas	53.06	0.025	0.0298

Exhibit 24: Carbon Dioxide, Methane, and Nitrous Oxide emissions factors for diesel and natural gas

Additionally, A factor of 46gCO_2e/kWh was obtained from NREL[13] for the estimated lifecycle emissions of solar PV.

Values for the cost of carbon were obtained from the publication "The Social Cost of Carbon And The Shadow Price Of Carbon: What They Are, And How To Use Them In Economic Appraisal In The UK" by Defra[14]. These values were given in 2007 GBP/tonneCO_2e and were then converted to 2020 GBP/tonneCO2e using GDP deflators provided in the UK Green Book data tables. The cost of carbon for 2022 was then obtained in 2022GBP/tonneCO2e using the deflators, and then escalated by 2% for the subsequent years in the analysis period (2023-2052). These values were finally converted to USD/tonneCO_2e using a currency conversion factor of 1.17.

4.2.7. Outage Data

Outage Hours

From data provided by CUC, outages which occurred between the hours of 8:00 am and 6:00 pm were extracted, as this represented daylight hours during which solar PV would be producing electricity and could therefore provide backup power, even without storage. As some outages may have extended beyond the 8 am to 6 pm window, and would have been eliminated from further analysis, this analysis therefore provides a conservative estimate of outage hours that would be mitigated by PV. Increased implementation of smart inverters would allow prosumers to both supply themselves as well as the grid with electricity generated from solar. Thus, for the customer-owned distributed PV scenarios, it was initially assumed that 99% of both scheduled and unscheduled outages could be mitigated, leaving 1% to force majeure occurrences where PV would not be able to supply power. Analysis on outage data provided by the CUC revealed that from the years 2016 to 2021, adverse weather events accounted for 11% of unscheduled outages. Without the use of storage, these adverse weather events could reduce the effectiveness of solar PV production and therefore 11% was subtracted from the initial 99% figure to give a conservative estimate of 88% of unscheduled outages that could be mitigated by PV. For the utility-scale scenarios, it was assumed that 50% of both scheduled and unscheduled outages could be mitigated by the PV. This is because in this scenario, solar farms would be installed on specific feeders so the ability of the PV to mitigate outages would be dependent on the locations of both the PV and the outage on the grid.

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12 U.S. Environmental Protection Agency. 2022. "Emission Factors for Greenhouse Gas Inventories." https://www.epa.gov/system/files/documents/2022-04/ghg_emission_factors_hub.pdf

13 National Renewable Energy Laboratory. 2012. "Life Cycle Greenhouse Gas Emissions from Solar Photovoltaics." https://www.nrel.gov/docs/fy13osti/56487.pdf

14 Richard Price, Simeon Thornton and Stephen Nelson. 2007. "The Social Cost of Carbon And The Shadow Price Of Carbon: What They Are, And How To Use Them In Economic Appraisal In The UK." https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/243825/background.pdf

The durations of the outages specified previously per feeder for each year from 2016 to 2021 were converted to hours, and the annual outage hours were calculated as a percent of the period hours for each corresponding year, which were obtained from CUC data. The average of the annual outage hours percentage was then multiplied by the average annual period hours to give an estimated value for the average outage hours per year.

Outage distribution factors (%) among feeders were also calculated. This was essentially a measure of how much of the total annual outage hours were incurred on each feeder based on the historic data provided.

Projected MWh Lost

For each year from 2016 to 2021, the feeder share of peak capacity was calculated using historical feeder peak data provided for those years. The average feeder share of peak capacity was then calculated.

Feeder peak capacities were then projected from 2023 to 2052 by multiplying the peak capacity of each feeder by its respective growth index and doing this for each successive year in the analysis period.

The average MWh lost for each feeder for each year in the analysis period was determined by calculating the product of the projected feeder peak, the average feeder share of peak capacity, the feeder outage distribution factor, and the average outage hours per year value. The MWh lost were summed across all feeders for each year to give the total projected MWh lost each year and those values were used going forward.

4.2.8. Land Impact Data

Two major inputs were used for land impact analyses. First, the RMI team gathered data on land impact for various technologies in square meters per MWh from the United Nations Economic Commission for Europe (UNECE). Land use was based on life-cycle assessments, meaning that the values not only account for the land of the energy plant itself but also the land used the mining of materials used for its construction, fuel inputs, decommissioning, and handling of the waste. The values are shown in the following table.

Technology	Land Impact Value (Square meter per MWh)
Distributed Solar Land Impact [m^2/MWh]	1.2
Natural Gas Land Impact [m^2/MWh]	1.3
Diesel Land Impact [m^2/MWh]	21

Exhibit 25: Land Impact Value by Technology

The second input for land impact was land cost. The average cost of land needed for mining materials, fuel inputs, decommissioning, and handling of the waste was assumed to be the USDA global average cost of land, which was 3,000 USD per acre. The cost of land in the Cayman Islands, which was relevant for utility scale solar, was calculated based on a review of real estate values in the DOE-prioritized areas for future utility solar farms. Specifically, the 2017 Cayman Property Review performed by Charterland Ltd. provided average land sales prices in KYD per square foot across the islands from 1999 to 2017. The team was able to extract the land sales in particular regions of interest for utility scale solar farms to gather the historical trends and project future trends.

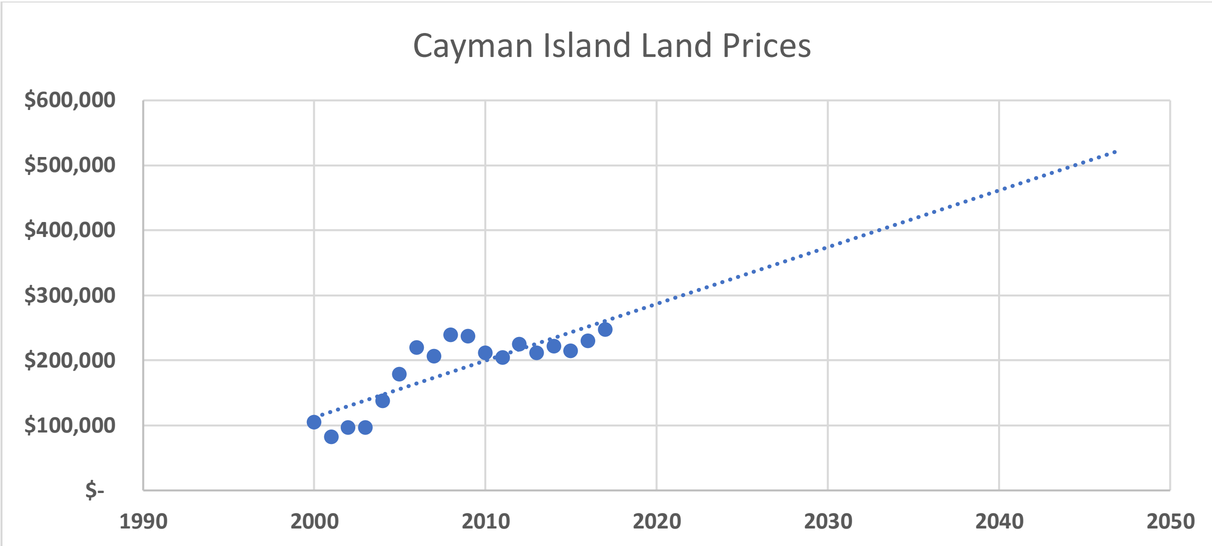

Exhibit 27: Average Land Costs in USD per acres based on Cayman Property Review 2017 future projection (dotted line). [15]

In addition to the assumption that land prices will continue to increase linearly, the team also took into consideration that as land is developed and bought in large swaths, the prices will increase due to demand-supply economics and competition for the remaining space. In general, there is an impact of large-scale land acquisition on land supply and prices.[16] The acquisition of land, especially at large-scale, results in a lower supply of land and thus land price increases. As an example, Tesla bought 2,000 acres of land at 100 million USD for a Gigafactory in Texas and there was a 45% land price increase in the region.[17] In other metrics, for every 100 acres bought, the land prices increase by 2.25%. These spikes were also added into the land cost projections.

Reflecting insight gleaned from various stakeholders, the team assessed the potential of using existing water ways for floating solar installations. Although floating solar is a proven technology on several inland water ways in Europe and Asia, it is still to be proven both as a technically and economically feasible option in the Caribbean. This includes its resiliency to tropical storms and hurricanes. There have been several incidents involving damage to floating PV systems due to flooding, electrical failure, wind events, etc. observed mainly for inland applications of floating PV. As such, floating solar in the Cayman Islands should be further assessed as a resilient option. Should this pathway be considered, there would be an impact on the resiliency score allotted to the value of solar. Given the strong interest expressed in the Cayman Islands exploring this pathway and given the likelihood of this technology to be proven both technically and economically feasible over the next 10-30 years, RMI explored the mitigating impact on land values in this study as a 2035 – 2050 low priority option.

[15] Charterland Ltd. 2017. "Cayman Property Review. An Independent Review by Charterland." https://www.charterland.ky/wp-content/uploads/2018/03/CPR-charterland-2017-ONLINE-version-2.pdf

[16] Bokhari, Sheharyar. 2019. "It's Not All About Demand: Home Prices are Sky-High Where It's Most Difficult and Most Expensive to Acquire and Develop Land https://www.redfin.com/news/value-of-house-vs-land/

[17] Rahman, Tahera. 2021. "House prices around Tesla Gigafactory have increased 45%, experts say it could keep climbing." https://www.kxan.com/news/local/austin/housing-prices-around-tesla-gigafactory-have-already-increased-nearly-45-experts-say-it-could-keep-climbing/

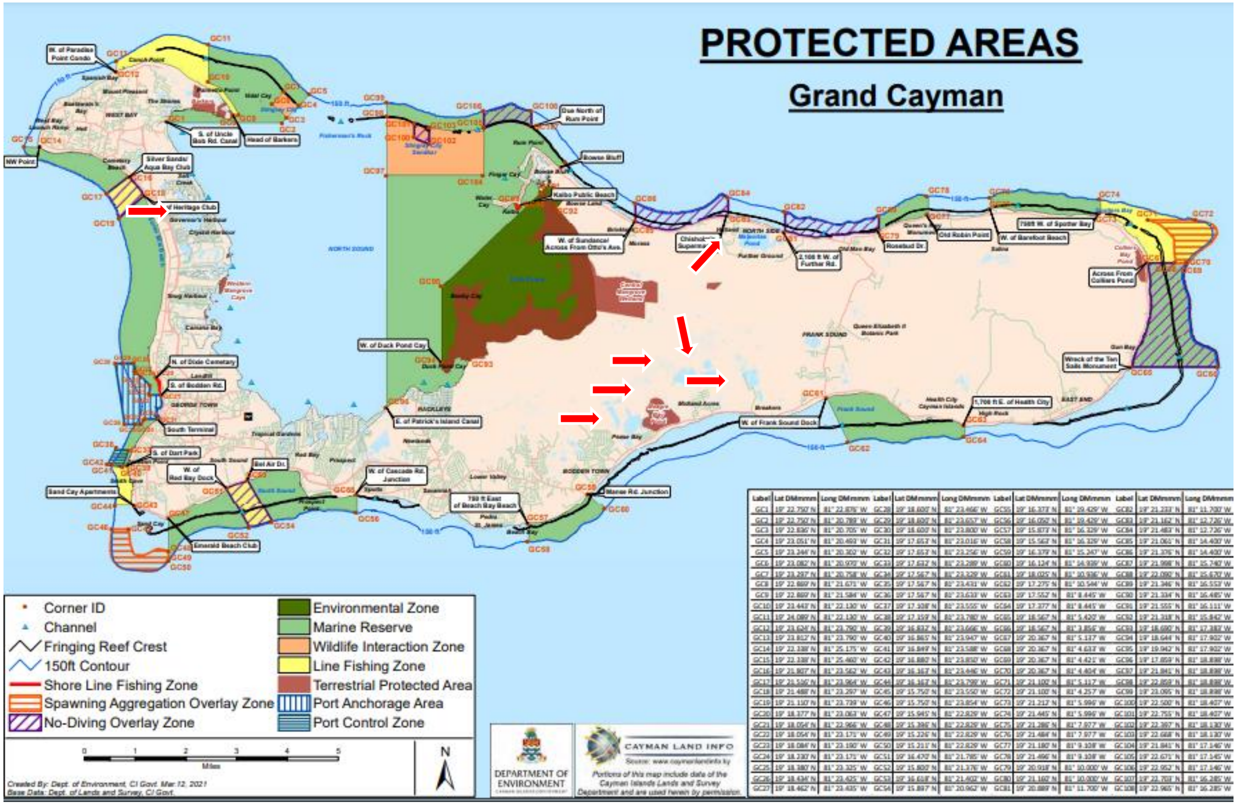

Exhibit 28: [Grand Cayman Department of Environment Marine Parks Boundary Maps](https://doe.ky/wp-content/uploads/2021/04/web3_Grand_Cayman_Boundary_Maps.pdf)[18] with RMI Markings of Identified Sites as red arrows "➡"

Approximately seven (7) sites, comprising 350 acres, were initially identified as inland waterways to be assessed for floating solar. However, of the seven sites identified, two (2) were determined to be protected waterways by the Department of Environment or designated as habitats to be protected by the National Trust. Of the remaining five (5) sites, one (1) was a natural pond with seasonal wet/dry cycles that would create challenges for floating solar. The four (4) remaining sites constitute approximately 200 acres that capable of facilitating roughly 55 MW of floating solar.

Finally, based on the National Energy Policy Unit, there are approximately 190 acres of man-modified Crown land have been identified as potentially suitable for utility scale solar[19]. Both the Crown land and waterways were included in the study at a greatly reduced lease rate of 5,000 USD/acre/year based on relevant crown lease rates in the region.

4.2.9. Economic Impact Data

Economic impact data was needed to determine the effect that the solar industry could have on the local economy, specifically regarding jobs and income from construction and O&M. NREL net solar impact value were used, which included the lost economic development from pursuing natural gas. The total value was USD 1,064,229 per MW in economic added value. This value aligned with inputs from stakeholders on the island, which estimated that there are roughly 20 new direct jobs per MW of solar on the island and 40

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[18] Cayman Islands Government Department of Environment. 2021. "Marine Parks Boundary Maps". https://doe.ky/wp-content/uploads/2021/04/web3_Grand_Cayman_Boundary_Maps.pdf

[19] Cayman Islands Government National Energy Policy Unit. "Electricity". https://www.energy.gov.ky/energy-security/electricity

more indirect jobs added. However, the NREL data was used as it was comprehensive of both the added value from solar and the lost value from not pursuing natural gas.

4.2.10. Recycling Data

End-of-life management of solar and batteries were raised as a point of interest by stakeholders and were therefore analyzed. For the Cayman Islands, recycling of these components entails the shipment of the used equipment to the United States. Quotations from a regional shipping company provided shipping cost estimates of $3000 USD per container. As recycling companies often pay for used equipment, the shipping cost would be offset by the amount received for the goods. For this analysis, it was estimated that the value of solar panels to be recycled would be 50% of the shipping cost, while that of BESS would be 90%. The latter value was selected as a conservative estimate due to upward trends which are projected for the value of used BESS in the coming years, as indicated by a US recycling company. Therefore, the net shipping costs were as follows:

- Solar panels - $1500 USD per container
- Batteries - $300 USD per container

It was estimated that a container would be able to hold 800 panels rated at 400W each. With this rating, 1 MW of solar would equate to 2,500 panels, which translated to 3.13 containers per MW of solar. A factor of 1 container per MW was used for batteries. Multiplying these factors by the net shipping costs gave the following values for shipping:

- Solar panels - $4688 USD per MW
- Batteries - $300 USD per MW

Labor requirements and associated costs were also calculated using the values shown in Exhibit 29 below:

Solar PV			BESS	
No. of panels per 1 MW	2,500		No. of containers per 1 MW	1
No. of minutes per panel	12		No. of minutes per MW	4,800
No. of hours per MW	500		No. of hours per MW	80
Rate $ per hour	$10.00		Rate $ per hour	$10.00
Total labor cost per MW	**$5,000**		**Total labor cost per MW**	**$800**

Exhibit 29: Labor requirements and costs for solar PV and BESS Recycling

4.2.11. NREL ATB

The NREL annual technology baseline was used to gather projections for the following variables for various technologies:

- VO&M costs per technology type
- F O&M costs per technology type
- Capital cost per technology type

4.2.12. IRP Data

The Cayman Islands IRP has the following data that was used for this study:

- The preferred expansion plan of the power sector (what generators are coming online up until 2045). This expansion plan was also used previously to design the future solar fleets.

- VO&M costs for landfill gas and WTE
- F O&M costs for landfill gas and WTE
- Capital cost for landfill gas and WTE

4.2.13. Heat Rates

Monthly Generator Heat Rate

Monthly generator heat rate was calculated using the historic monthly generation data that was provided by CUC for each unit. A weighted average of the heat rate for each unit and the amount of electricity generated by that same unit was calculated to determine a weighted monthly heat rate from Jan 2018 to July 2022.

Two trends were determined using the historical values: an overall annual increase and a seasonal variation. The average annual increase was found to be 0.3%, and this value was used to project future monthly heat rates that fluctuated based on seasonal variations in average heat rates.

Hourly Heat Rate

Once projected monthly heat rates were determined, hourly heat rates were deduced from hourly demand and load profiles provided by CUC for 4 months. During peak demand, which consistently happens between 6:00pm-8:00pm in the Cayman Islands, peak generators begin operation. For CUC, the peak generators are small units with very high heat rates. Additionally, the largest baseload units have the lowest heat rates- and would therefore be operating during the lowest demand periods, 1:00am to 5:00am. The team therefore determined that during peak hours, there would be an increased heat rate compared to the daily average and during valley hours, there would be a decreased heat rate compared to the daily average. In fact, the shift in heat rates over the course of the day would directly correspond to the shift in generation over that day due to the prioritization order in which CUC dispatches its generators.

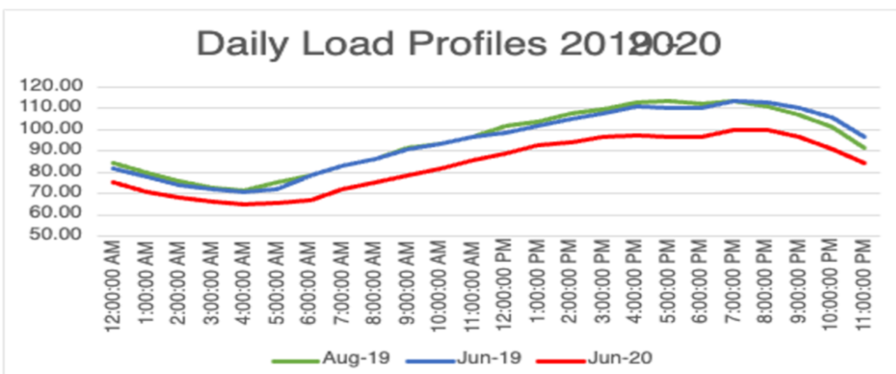

Exhibit 30: Daily CUC load profiles from 2019-2022

Effectively, the team determined the typical percentage change in generation every hour from the daily average. These same percentages were then used to determine the adjusted hourly heat rates from the projected monthly heat rates.

Monthly Solar Weighted Heat Rate

The heat rate of marginal solar can be thought of as the heat rate of a fossil fuel generator that would be required to produce the same kWh generated from the solar plant at the given hour – OR – the avoided heat rate of distributed solar. It was calculated on an hourly basis for the 30-year analysis period. The inputs were the hourly solar PV production, the solar PV capacity, and the hourly weighted utility heat rate (calculation described above). First, the hourly weighted utility heat rate [Btu/kWh] was multiplied by the hourly solar PV production [kWh] to get the total heat in BTU required to generate the electricity in that hour. Then, the monthly heat rate of marginal solar was calculated by summing all the heat required in a month and dividing by the total kWh generated that same month.

5. VOS Methodology: Variables

The bulk of the VOS study involved the assessment of various VOS variables. VOS variables are categories that represent the positive value (avoided cost) or negative value (incremental cost) attributed to the penetration of solar. For example, a common variable in VOS studies is the avoided fuel cost, which is the positive value that solar adds by avoiding fuel that would have otherwise been used to generate electricity at a centralized fossil fuel power plant subject to fuel prices and heat rate. Variables can range from utility/system impacts on the transmission, distribution and generation level to societal impacts related to land impact, air pollution, and water use to risk. Which variables, or value categories, are included and monetized in the study and whether they represent costs or benefits substantially affect the final result. In order to identify the most relevant variables for the Cayman Islands, the team carried out a literature review of VOS studies, which is described in Section 6.

The RMI team identified sixteen variables for this VOS study that were of contextual importance to the Cayman Islands, informed by a literature review of previous VOS studies to determine the variables to be included. Exhibit 31 shows the sixteen variables used for the Cayman VOS study, distinguished as either direct utility impact, risk impact, or environmental/economic impact.

Direct Utility Impact (Energy/Grid)	
1.	Net avoided energy costs
2.	System Losses
3.	Net avoided Generation Capacity
4.	Avoided Transmission Capacity
5.	Avoided Distribution Capacity
6.	Avoided Reserve Capacity
7.	Integration Costs
Risk Impact	
8.	Fuel Price Volatility
9.	Reliability and Resiliency
10.	Market Price Response
Environmental/Economic Impact	
11.	Net carbon Emissions
12.	Other pollutants
13.	Net water Use
14.	Net avoided Land Impact
15.	Land Use
16.	Net economic Development

Exhibit 31: Variables used for the Cayman Islands VOS study, categorized as direct utility impact, risk impact or environmental/economic impact.

In addition to selecting the variables to include in a study, each variable must be specifically defined. The approach to defining the value categories and the methodologies used for quantifying them is crucial to measuring the final value of solar. The perspective from which the value is assessed is also important. Different methodologies or a varying perspective for the same variable can result in widely different monetized values, and therefore a distinct value of solar. Understanding the best methodology for each variable for the local context was an important process in the study. Methodologies were carefully selected for each variable based on data received from stakeholders, data acquired by the RMI team, local considerations, and educated assumptions. This section describes the methodology for each of the sixteen variables in depth.

5.1. Net Avoided Energy Costs

As a whole, this variable represents the cost that would have otherwise been needed to generate the same amount of energy at a centralized fossil fuel power plant to meet customer needs subject to fuel prices, fixed O&M costs, variable O&M costs, heat rate, and capacity factors of solar and utility generators. This variable was split into 3 subcategories to clearly separate and simplify the methodologies and calculations. To find the final value of solar for the net avoided energy costs, all three of the subcategory values were summed as follows:

$$VOS_{energy} = VOS_{FOM} + VOS_{VOM} + VOS_{fuel}$$

where

- VOS_{energy} = value of solar for energy costs, $[\$/kWh]$
- VOS_{FOM} = value of solar for fixed O&M, $[\$/kWh]$
- VOS_{VOM}= value of solar for variable O&M, $[\$/kWh]$
- VOS_{fuel} = value of solar for fuel costs, $[\$/kWh]$

5.1.1. Net Avoided Fixed O&M costs

The use of distributed solar generation results in a displacement of conventional electricity generation plants, and therefore an avoided cost of plant operation and maintenance fixed costs. Fixed costs represent the costs that are incurred irrespective of use and therefore are viewed as long-run maintenance costs. Distributed solar can replace these costs as the need for centralized plants is deferred and avoided. The methodology to calculate the net avoided fixed O&M costs to the utility (utility cost) depends on several inputs:

- Discount factor
- The capacity of the DSG [kW] and production of DSG [kWh]
    - Capacity factor can be calculated from this
- The capacity of utility generation [kW] and production of utility generation [kWh]
    - Capacity factor can be calculated from this
- Utility equivalent capacity of solar (effective capacity)
- Utility fixed O&M cost [USD/kW]

First, the discount factor was calculated by using the Cayman Islands discount rate and year number. It describes the uncertainty and fluctuation of the value of money over time and was found by applying the following formula:

$$D_n = \frac{1}{(1+r)^n}$$

where

- D_n = discount factor for year n
- r = discount rate
- n = year number

The capacity factor for solar was determined by dividing the estimated production of the solar fleet in kWh by the total possible amount of solar production if the solar capacity was operating at 100% during the time period considered. The capacity factor calculation compares the estimated production to the theoretical maximum solar production, and it does not assume solar production operates at the maximum theoretical value.

$$CF_n = \frac{P_{s,n}}{(V_{s,n} \times 8760)}$$

where

- CF_n = capacity factor for year n
- $P_{s,n}$= solar production for year n, $[kWh]$
- $V_{s,n}$ = solar capacity for year n, $[kW]$

The capacity factor for the utility generators was calculated in an identical manner.

The ratio of the solar capacity factor to the utility capacity factor can be multiplied by the total DSG capacity [kW] to determine the “utility equivalent” capacity of the solar fleet. Essentially, this is the adjusted DSG capacity considering that 1 kW of solar capacity will not produce as many kWh’s as 1 kW of utility capacity due to the differences in inefficiencies, which is captured in the capacity factor. The equation for determining the utility equivalent capacity of solar is as follows:

$$V_{ueq,n} = \frac{V_{s,n} \times CF_{s,n}}{CF_{u,n}}$$

where

- $V_{ueq,n}$ = utility equivalent capacity of the solar fleet for year n, $[kW]$
- $V_{s,n}$ = solar capacity for year n, $[kW]$
- $CF_{s,n}$ = solar capacity factor for year n
- $CF_{u,n}$ = utility capacity factor for year n

The fixed O&M cost was estimated for each technology in the 2017 IRP. These values were used for the existing generators, the future landfill gas generator, and the future WTE generator. For the other technologies (NG, utility scale solar, wind, and battery), the NREL Annual Baseline Technology data was used. A weighted fixed O&M cost was calculated by taking the sum product of the capacity of each technology [kW] with the fixed O&M cost [USD/kW] for that technology for each time-period of interest.

$$FOM_n = \underbrace{\frac{\sum_{tech}(V_{u,n} \times FOM_{u,n})}{\sum V_{u,n}}}_{\text{Weighted Utility FO\&M}}$$

where

- FOM_n = fixed O&M cost for year n, $[\$/kW]$
- $V_{u,n}$ = utility capacity for year n for each technology in the utility fleet, $[kW]$
- $FOM_{u,n}$ = utility fixed O&M for year n for corresponding technology, $[\$/kW]$

Once the net avoided fixed O&M costs were determined, the discounted utility cost was calculated by multiplying the discount factor by the utility equivalent solar capacity [kW] and the net avoided fixed O&M cost minus the additional solar fixed O&M cost. The solar fixed O&M costs include routine maintenance and operation costs that add an extra cost to the solar resource.

$$C_{u,n} = D_n \times V_{ueq,n} \;\; [kW] \times (FOM_n \;\; [\$/kW] - FOM_{solar} \;\; [\$/kW])$$

where

- $C_{u,n}$ = discounted avoided utility cost for year n for fixed O&M, $[\$]$
- D_n = discount factor for year n
- $V_{ueq,n}$ = utility equivalent capacity of the solar fleet for year n, $[kW]$
- FOM_n = fixed O&M cost for year n, $[\$/kW]$
- FOM_{solar} = fixed O&M cost of solar for year n, $[\$/kW]$

Finally, to get the value of solar for the net avoided fixed O&M cost, the sum of the discounted avoided utility costs for all years was divided by the sum product of the total solar production over the 30 years and the discount factor. The result was the value of solar for the avoided fixed O&M variable.

$$VOS_{FOM} = \frac{\sum_n C_{u,n} \;\; [\$]}{\sum_n (P_{s,n} \times D_n) \;\; [kWh]}$$

where

- $C_{u,n}$ = discounted avoided utility cost for year n for fixed O&M, $[\$]$
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.1.2. Avoided Variable O&M costs

The use of DSG also results in avoided plant operation and maintenance variable costs [USD/kWh]. The variable O&M costs are linked to maintenance of the capacity that has been used during the year. The value of the variable O&M costs to the utility (utility cost) depends on several inputs:

- Discount factor (calculation explained above)
- Solar system output [kWh] – direct output from PV Watts
- Utility variable O&M cost [USD/kWh]
- Solar O&M cost [USD/kWh]

The variable O&M cost was estimated for each technology in the 2017 IRP. Then, a weighted variable O&M cost was calculated by taking the sum product of the capacity of each technology with the variable O&M cost [USD/kWh] for that technology and dividing it by the total utility capacity for each time period of interest. There were assumed to be no variable O&M costs for solar energy and therefore there was no need to calculate a net avoided variable O&M value.

$$VOM_n = \underbrace{\frac{\sum_{tech}(V_{u,n} \times VOM_{u,n})}{\sum V_{u,n}}}_{\text{Weighted Utility VO\&M}}$$

where

- VOM_n = variable O&M cost for year n, $[\$/kWh]$
- $V_{u,n}$ = utility capacity for year n for each technology in the utility fleet, $[kWh]$
- $VOM_{u,n}$ = utility variable O&M for year n for corresponding technology, $[\$/kWh]$

Then, the utility cost was calculated by multiplying the discount factor, by the solar production [kWh] by the weighted fixed O&M cost [USD/kWh].

$$C_{u,n} = D_n \times P_{s,n} \ \ [kWh] \times VOM_n \ \ [\$/kWh]$$

where

- $C_{u,n}$ = avoided utility cost for year n for variable O&M, $[\$]$
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n
- VOM_n = variable O&M cost for year n, $[\$/kWh]$

Finally, to get the value of solar for the avoided variable O&M cost, the sum of the discounted avoided utility costs for all years was divided by the sum product of the total solar production over the 30 years and the discount factor. The result was the value of solar for the avoided variable O&M variable.

$$VOS_{VOM} = \frac{\sum_n C_{u,n} \ [\$]}{\sum_n (P_{s,n} \times D_n) \ [kWh]}$$

where

- $C_{u,n}$ = discounted avoided utility cost for year n for variable O&M, [$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.1.3. Avoided Fuel Costs

The use of DSG also avoids the need for conventional generators to use fuel, and thus saves the Cayman Islands a large sum of money that would otherwise have gone towards fuel costs. There are two fuels that CUC must consider: diesel and natural gas (NG). To determine the avoided fuel costs, there are several important inputs:

- Discount factor
- Solar production [kWh]
- Heat rate of marginal solar (avoided heat rate if solar production was coming from a conventional generator, calculation described above)
- Generation from Diesel plants
- Generation from NG plants
- Diesel fuel price [USD/MMBtu]
- Natural Gas price [USD/MMBtu]

To calculate the generation from diesel plants and NG plants, the team first looked at the current utility capacity. Assuming that the landfill gas and WTE generators would yield relatively small enough generation, the contributions of these generators to the total generation was assumed to be negligible. The team then assumed that utility scale solar would operate according to the production output of the simulated utility fleet and that utility wind would operate with a 25% capacity factor on average, which was used to calculate the estimated generation from utility wind. The remaining generation, therefore, had to come from fossil fuel. From here, the team assumed that, as diesel is phased out, NG will become the preferred fuel choice for CUC over diesel. Therefore, any NG capacity will be utilized at maximum capacity, which the team assumed to be a 90% capacity factor. This allowed the team to determine the generation coming from NG and thus, from diesel, for the 30-year period.

Fuel prices were taken from the fuel price input section. The team compared the potential solar production with the diesel generation and natural gas generation, to determine how much of that fossil generation could be offset. When making these determinations, the team assumed that diesel was the first fuel offset since it is more expensive and that, only after all diesel generation was offset, additional solar production would begin to offset natural gas generation. The corresponding fuel price for the offset generation was used to determine the utility price. For all years, the fuel price was converted into USD per MMBtu. The net price for fuel in [USD/kWh] is then calculated for each fuel separately by multiplying the fuel price in [USD/MMBtu] by the marginal heat rate of solar [Btu/kWh] and a unit conversion from Btu to MMBtu.

$$Price_{d_{net},n} = Price_{d,n} \ \ [\$/MMBtu] \times HR_{s,n} \ \ [Btu/kWh] \times 10^{-6}$$

where

- $Price_{d_{net},n}$ = utility price of acquiring needed diesel fuel based on heat rate for year n, [\$/kWh]
- $Price_{d,n}$ = fuel price of avoided diesel fuel for year n, $[\$/MMBtu]$
- $HR_{s,n}$ = heat rate of marginal solar for year n, $[Btu/kWh]$

$$Price_{NG_{net},n} = Price_{NG,n} \ \ [\$/MMBtu] \times HR_{s,n} \ \ [Btu/kWh] \times 10^{-6}$$

where

- $Price_{NG_{net},n}$ = utility price of acquiring needed NG fuel based on heat rate for year n, [\$/kWh]
- $Price_{NG,n}$ = fuel price of avoided NG fuel for year n, $[\$/MMBtu]$
- $HR_{s,n}$ = heat rate of marginal solar for year n, $[Btu/kWh]$

Then, the utility prices in USD per kWh from diesel and natural gas were added together to get the total utility price.

$$Price_{total,n} = Price_{NG_{net},n} \ \ [\$/kWh] + Price_{d_{net},n} \ \ [\$/kWh]$$

A check was made to ensure that the total amount of generation coming from solar did not exceed the diesel fuel and NG generation. If solar generation did indeed exceed both diesel and NG generation- then the maximum offset generation was limited by the amount of diesel/NG generation rather than the solar generation. This became relevant when looking at utility scale solar. After the solar production offsetting fossil fuel generation was confirmed, it was multiplied by the discount factor and total solar production for the time period of interest to get the avoided utility cost.

$$C_{u,n} = D_n \times P_{s,n} \ \ [kWh] \times Price_{total,n} \ \ [\$/kWh]$$

where

- $C_{u,n}$ = avoided utility fuel cost for year n, [\$]
- D_n = discount factor for year n
- $P_{s,n}$= solar production for year n, $[kWh]$
- $Price_{total,n}$ = utility price of acquiring needed fuel based on heat rate for year n, [\$/kWh]

Finally, to get the value of solar for the avoided fuel costs, the sum of the discounted avoided utility costs for all years was divided by the sum product of the total solar production over the 30 years and the discount factor. The result was the value of solar for the avoided fuel costs variable.

$$VOS_{fuel} = \frac{\sum_n C_{u,n} \ [\$]}{\sum_n (P_{s,n} \times D_n) \ [kWh]}$$

where

- $C_{u,n}$ = discounted avoided utility cost for year n for fuel costs, [$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.2. System Losses

This variable represents the avoided costs when considering the compounded value of the additional energy generated by CUC's central plants that would otherwise be lost due to inherent inefficiencies (electrical resistance) when delivering energy to the customer via the transmission and distribution system (namely auxiliary losses, station losses, and T&D losses). The necessary inputs for the methodology are:

- Discount factor
- Average % of losses
- Total utility generation [kWh]
- Solar production [kWh]
    - Avoided losses when solar is included
- Avoided fuel cost [USD/MMBtu]

From the system losses input data, the average percentage of plant use losses (auxiliary use), generation losses (station losses), and T&D had been calculated. These percentages were used to determine the expected total losses for each year [kWh] if the solar generation were to experience equivalent losses during the same time period. For distributed solar, station losses and T&D losses could be avoided from the generation, which represented around 4% each year.

The cost that was associated with these losses is the fuel cost and variable O&M cost. Recall that the fixed costs are constant regardless of plant use and the variable costs are relatively small compared to fuel costs. Therefore, the utility cost for these avoided system losses was calculated by multiplying the fuel cost [USD/kWh] by the avoided losses [kWh] by the discount factor.

$$C_{u,n} = D_n \times L_{avoided,n} \ [kWh] \times Price_{net,n} \ [\$/kWh]$$

where

- D_n = discount factor for year n
- $C_{u,n}$ = avoided utility cost for year n for system losses, [$]
- $L_{avoided,n}$ = avoided losses for year n when solar is included $[kWh]$
- $Price_{net,n}$ = utility price of acquiring needed fuel based on heat rate plus variable O&M for year n, [$/kWh]

For the utility scale value of solar analysis, the avoided system losses only included the avoided auxiliary losses. The assumption was that the utility scale solar plants would still be operating widely on the transmission and distribution grid and therefore no T&D or station losses could realistically be avoided.

Finally, to get the value of solar for the avoided system losses, the sum of the discounted avoided utility costs for all years was divided by the sum product of the total solar production over the 30 years and the discount factor. The result was the value of solar for the system losses variable.

$$VOS_{loss} = \frac{\sum_n C_{u,n} \ \ [\$]}{\sum_n (P_{s,n} \times D_n) \ \ [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for system losses, [\$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.3. Net Avoided Generation Capacity

The net avoided generation capacity was calculated in a similar way to the net avoided fixed O&M costs. The logic behind this variable is that the use of DSG results in a displacement of conventional electricity generation plants, and therefore the avoided new build costs of additional plants coming online. However, some of these savings will be later reinvested into new solar modules at the end of the 25 year warranty and new inverters every 10 years. The inputs needed for the methodology are as follows:

- Discount factor
- The capacity of the DSG [kW] and production of DSG [kWh]
  - Capacity factor
- The capacity of utility generation [kW] and production of utility generation
  - Capacity factor
- Utility capital cost [USD/kW]
- Modules costs as part of total build cost [%]
- Inverter costs [USD/kW]

The ratio of the capacity factor of solar to the capacity factor of utility generation was again used to determine what 1 new kW of solar capacity would equate to in utility capacity terms. Therefore, the new build capacity of solar was calculated taking into account the capacity factor ratio, which gave the utility equivalent new build capacity.

The capital cost was estimated for each technology in the 2017 IRP and was used for this analysis. Then, a weighted capital cost was calculated by taking the sum product of the capacity of each technology [kW] with the capital cost [USD/kW] for that technology and dividing by the total capacity for each time period of interest.

$$Build\ \ Cost_n = \underbrace{\frac{\sum_{tech}(V_{u,n} \times Build\ \ Cost_{u,n})}{\sum V_{u,n}}}_{\text{Weighted Utility Build Cost}}$$

where

- $Build\ \ Cost_n$ = build cost for year n, $[\$/kW]$
- $V_{u,n}$ = utility capacity for year n for each technology in the utility fleet, $[kW]$
- $Build\ \ Cost_{u,n}$ = utility build cost for year n for corresponding technology, $[\$/kW]$

Then, the utility cost was calculated by multiplying the discount factor by the utility equivalent new build solar capacity [kW] by the weighted build cost.

$$C_{u,n} = D_n \times V_{ueq,n}\ \ [kW] \times Build\ \ Cost_n\ \ [\$/kW]$$

where

- $C_{u,n}$ = avoided utility cost for year n for new build generation, $[\$]$
- D_n = discount factor for year n
- $V_{ueq,n}$ = utility equivalent capacity of the solar fleet for year n, $[kW]$
- $Build\ \ Cost_n$ = build cost for year n, $[\$/kW]$

Next, the team calculated the amount of this saved money that would be reinvested into solar panel and inverter replacements. Inverter costs used were 15 USD cents per kW (based on responses from experts in the region) and inverters were considered to be replaced every 10 years. Additionally, modules make up 25% of the total capital cost of a new build solar system and are replaced every 25 years. With these inputs and assumptions, the team was able to calculate the amount of savings that would need to be reinvested into replacements associated with the solar system, considering discount factors. These reinvestments had to be subtracted from the avoided utility cost for new build generation in order to find the net avoided generation capacity as follows:

$$C_{u_{tot},n} = C_{u,n}\ \ [\$] - Inverter\ \ Cost_n[\$] - Module\ \ Cost_n[\$]$$

where

- $C_{u_{tot},n}$ = net avoided utility cost for year n for new build generation, $[\$]$
- $C_{u,n}$ = avoided utility cost for year n for new build generation, $[\$]$
- $Inverter\ \ Cost_n$ = reinvested utility cost for year n for solar inverter replacements, $[\$]$
- $Module\ \ Cost_n$ = avoided utility cost for year n for solar module replacements, $[\$]$

Finally, to get the value of solar for the net avoided generation capacity, the sum of the discounted net avoided utility costs for all years was divided by the sum product of the total solar production over the 30 years and the discount factor. The result was the value of solar for the net avoided generation capacity variable.

$$VOS_{gen} = \frac{\sum_n C_{u,n} \;\; [\$]}{\sum_n (P_{s,n} \times D_n) \;\; [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for new build generation, [$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.4. Avoided Transmission Capacity

This variable measures the value of the transmission capacity deferred from DSG. The total utility capacity [kW] was used to determine the annual capacity increase each year. The total transmission cost was taken from the projected capital expenditure input. Next, the deferrable transmission spending was estimated based on the assumption that distributed solar would only defer upgrades, and not impact maintenance or new installation on the transmission system. A conservative estimate of 5% was used as the percentage of total spending that could be deferred for distributed solar.

Then a transmission cost per unit growth of the utility capacity was determined for each year based on the deferrable transmission cost for that year. To calculate this value, the total deferrable transmission costs over the 30-year period was summed and divided by the total new build capacity to obtain an initial cost per unit growth of utility capacity in USD per kWh. For each subsequent year, this cost was multiplied by the discount factor to obtain the net present value.

$$C_{tran,n} = D_n \times \frac{\sum Trans_{deferrable,n} \;\; [\$]}{\sum Cap_{new,n} \;\; [kW]}$$

where

- $C_{tran,n}$ = discounted transmission cost per unit growth of capacity for year n, $[\$/kW]$
- D_n = discount factor for year n
- $Trans_{deferrable,n}$ = deferrable transmission spending for year n, [$]
- $Cap_{new,n}$= new utility capacity for year n, $[kW]$

Next, the discounted transmission cost per unit growth was multiplied by the utility equivalent new build solar capacity (considering capacity factor) to get the utility cost in USD.

$$C_{u,n} = V_{ueq,n} \ \ [kW] \times C_{tran,n} \ \ [\$/kW]$$

where

- $C_{u,n}$ = avoided utility cost for year n for new transmission capacity, [$]
- $V_{ueq,n}$ = utility equivalent capacity of the solar fleet for year n, $[kW]$
- $C_{tran,n}$ = discounted transmission cost per unit growth of capacity for year n, $[\$/kW]$

The reason that solar is expected to defer transmission is based on a working assumption from the team that the 20 MW battery coming online would be up and operational and therefore excess solar generation would be able to shave peak demand. Additionally, necessary BESS would be added as part of the integration costs for distributed solar. For utility scale solar, this avoided capacity cost was assumed to be zero since the utility scale solar system will still be fully connected and operational on the transmission grid.

To get the final value of solar result for the avoided transmission capacity variable, the sum of the discounted avoided utility costs for all years is divided by the sum product of the total solar production over the 30 years and the discount factor.

$$VOS_{trans} = \frac{\sum_n C_{u,n} \ \ [\$]}{\sum_n (P_{s,n} \times D_n) \ \ [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for new transmission capacity, [$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.5. Avoided Distribution Capacity

The avoided distribution capacity is calculated in a similar way to the transmission capacity and represents the value of the distribution capacity deferred from DSG. Again, the assumption was that distributed solar would only defer upgrades, and not impact maintenance or new installation on the transmission system. An estimate of 20% was used as the percentage of total distribution spending that could be deferred for distributed solar. For utility scale solar, this avoided capacity cost was also assumed to be zero since the utility system will still be fully connected and operational on the distribution grid.

A distribution cost per unit growth of the utility capacity was determined for each year based on the deferred distribution expenditure and new build utility capacities for all year. This distribution cost per unit growth was multiplied by the utility equivalent new build solar capacity to get the utility cost in USD. The final value of solar for this variable was determined in the same manner described above:

$$VOS_{dist} = \frac{\sum_n C_{u,n} \ \ [\$]}{\sum_n (P_{s,n} \times D_n) \ \ [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for new distribution capacity, [\$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.6. Avoided Reserve Capacity

The avoided reserve capacity refers to the amount of fossil fuel generation capacity that is no longer required to meet the reserve margin requirement due to solar generation displacing fuel generation. The utility cost for this variable was calculated as the assumed reserve margin percentage, i.e., 45%, of the utility cost for Avoided Generation. The utility cost was then discounted for each year in the time-period of the analysis. The sum of the discounted utility costs gave the utility present value, and this was divided by the sum of the discounted solar PV production throughout the years to give the VOS value for this variable.

$$VOS_{res} = \frac{\sum_n C_{u,n} \ \ [\$]}{\sum_n (P_{s,n} \times D_n) \ \ [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for ancillary services due to avoided reserve capacity, [\$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.7. Integration Costs

As solar penetration on the grid increases, interventions are required to ensure that there is no adverse effect on grid stability due to the intermittent nature of solar production. These interventions can take the form of BESS, feeder upgrades, feeder splitting or even substation upgrades. Calculation of the VOS value for this variable aimed to determine the net the cost of the BESS required to maintain grid stability against the other types of grid upgrades that would have to occur otherwise. The methodologies used to calculate this variable were slightly different for the customer-owned distributed and utility-scale scenarios. The former entailed analysis at the feeder level and contained upgrade costs, while the latter looked at the substation level and upgrade costs were replaced by substation costs. More detail is provided in the following.

5.7.1. Customer-owned Distributed PV Scenarios

For these scenarios, the peak demand expected on each of the 34 feeders in the system was projected for 2023 by multiplying the most recent peak value (MW) obtained from CUC data by the feeder's respective load growth index. For the successive years in the analysis, growth in each feeder's peak demand was obtained by distributing the growth in projected generation demand (modelled in the demand forecast) among the feeders in the same ratio that already existed. This represented natural growth in the loading on the feeder over time. Once the load on the feeder surpassed the feeder's planning capacity (as highlighted in CUC data), this would normally imply a need for upgrades or modifications to either the feeder or substation. This occurrence was observed for 2 feeders which necessitated further analysis as explained in the following sections.

Analysis on All Feeders

BESS for Regulation

BESS can be useful in smoothing intermittent PV production and absorbing excess PV production to mitigate power flow issues which occur as the penetration of solar on a feeder increases. As a result, the VOS analysis adopted the approach to install BESS for regulation at a feeder once the solar penetration exceeded 20% at that feeder. The size of the BESS required for each feeder was assumed to be 20% of the installed solar capacity at the same feeder.

Analysis on Feeders Exceeding Planning Capacity

Distributed Solar Impact on Feeder Upgrade Deferral

Distributed solar uptake by customers on a particular feeder could potentially help to defer and/or reduce the extent of these upgrades by facilitating reduction in the feeder peak and also through the effects of BESS, which would be required for smoothing of intermittent PV generation. However, the inclusion of BESS would incur a cost. Analysis of this variable therefore sought to understand the tradeoff between the benefits of the distributed solar on the distribution system and the costs of maintaining grid stability when the solar is installed.

The hourly generation profile from 19 August 2019, a historical peak day, was scaled in the same proportion to meet the projected peak demand for 2032, which was the year in which the demand on a feeder first exceeded its planning capacity. The hourly generation was adjusted for generation losses of 2.4% to give a profile for the demand across all feeders in the distribution system in 2032. A similar procedure was carried out for other maxed-out feeders, where an hourly generation profile for the year in which they exceed their capacity was developed by scaling the hourly load such that the feeder peak hour coincided with the generation peak hour. This resulted in hourly peak day profiles in the year each feeder maxed out in a business-as-usual case where there was no additional uptake of distributed solar.

It was assumed that the uptake of distributed solar across the feeders would follow the same pattern as currently exists based on CUC data. Therefore, the projected capacity of DG on each feeder for each year in the analysis period (modelled earlier) was distributed across the feeders in the existing ratio for each year. Additionally, hourly solar PV production profiles for the peak day in the year that the respective feeders maxed out were developed based on the distribution of PV production throughout the day (modelled earlier).

The peak day hourly solar production profile for each feeder was added to its BAU peak day profile to investigate the effect of solar on the feeder load throughout the day. It was observed that solar helped to reduce the peak on one of the two aforementioned feeders to such an extent that it was no longer maxed out and therefore any required upgrade would be deferred. The other feeder also experienced a decrease in peak load, however it was still greater than 95% of capacity, indicating the need for an intervention such as a feeder upgrade, feeder splitting or BESS installation.

Inclusion of BESS for Load Reduction and Feeder Upgrade Deferral

Solar PV generation is intermittent and can vary from one moment to another based on atmospheric conditions (e.g. clouds passing overhead). This can lead to voltage fluctuations which reduce the quality of power provided by the grid. Additionally, when the amount of electricity generated by a distributed solar system exceeds the local demand, there is an occurrence of reverse power flow which can cause issues such as voltage irregularities and equipment malfunction. To mitigate these adverse effects, the load on the feeder can be reduced by splitting the feeder, upgrading the feeder, or even constructing a new substation. Another option is to implement a BESS which can potentially mitigate both the intermittency and reverse power flow issues. BESS can also help to reduce the load on feeders by discharging during the evening peak after being charged by excess solar production (thereby mitigating reverse power flow issues) during the day. This load reduction can help to defer upgrades needed for feeders.

For the feeder which remained over 95% capacity, the BESS capacity required was approximated as 3 times the excess solar capacity. This was enough to reduce the load to below 95% of the feeder capacity and could also provide the other functions discussed previously. The BESS was modelled to discharge when the load on the feeder exceeded 95% of its capacity, which happened during the evening peak. The highest capacity discharged at any hourly interval indicated the size of the BESS that would be required. The value was rounded up to the nearest 10 kW and then used for estimates of cost.

BESS for Accelerated Uptake

Whether it is because of natural load growth, uptake of distributed solar, or a combination of both factors, feeders eventually approach their planned capacity. This limits the uptake of additional solar on the feeders which can slow the rate of adoption and can also lead to inequitable opportunities for customers who would like to install solar but are unable to due to the lack of capacity. The two feeders which maxed out during the analysis period therefore needed additional BESS capacity to allow for continued uptake of solar.

In this analysis, the size of BESS that would be required to facilitate further uptake of solar once a feeder's capacity was exceeded was estimated to be equal to the excess capacity of solar on the feeder minus the BESS size calculated for regulation, as discussed earlier. This capacity was subtracted because it was assumed that the BESS installed for regulation would be charged by solar during the day, reducing the load on the feeder while incidentally mitigating power flow issues.

BESS for Spinning Reserve

The analysis also looked at the use of BESS for the provision of 20 MW of spinning reserve capacity for the utility. The value provided by the spinning reserve battery was determined to be equivalent to the value of avoided fuel-use losses for spinning reserve provision. It was assumed that the BESS will meet the majority of the spinning reserve requirement that was currently being met by fossil fuel generation. Such generation from fossil fuels will have losses due to the thermodynamic efficiency of electricity generation using that fuel, meaning that with more fuel burned there is an incremental increase in losses – however these losses are avoided if spinning reserve is provided by batteries and there is reduced spinning reserve from fossil fuel generation.

The losses from fuel use for spinning reserve was determined by calculating the annual n-1 spinning reserve provision in kWh and dividing this by the product of the fuel efficiency in kWh per imperial gallon and the reduction in efficiency from incremental fuel burn. This value was then multiplied by the price of fuel to determine the value of fuel losses in each year, and discounted over the analysis period to provide the avoided losses value from fuel use for the spinning reserve battery.

The cost of the spinning reserve battery was also taken into consideration, with the assumption that the spinning reserve battery will be replaced every 10 years. To determine this cost, the capacity of the spinning reserve battery installed every 10 years was multiplied by the BESS Installed Cost variable (highlighted in 5.7.3. BESS Cost Estimates), and discounted over the analysis period. The net value from the avoided losses from fuel use and the cost of the spinning reserve battery determined the net value provided by the spinning reserve battery.

BESS Costs

For the customer-owned distributed PV scenarios, the VOS value for BESS costs was determined by calculating separate VOS sub-values for the following considerations:

- Cost of capacity required for voltage and frequency regulation (-)
- Cost of capacity required to facilitate uptake of solar (-)
- Cost of capacity required for spinning reserve (-)
- Avoided costs due to reduced fuel losses from genset spinning reserve operation (+)
- Opportunity cost associated with land use for BESS (-)
- Cost of recycling at end-of-life (-)

The unit cost of utility-scale BESS was estimated at $1,934,720 USD/MW based on the pricing for Tesla's Megapack, plus a 20% premium for shipping and installation. The costs of the BESS capacity required for each of the three value streams in each year of the analysis period were calculated based on this figure.

The land use cost for the BESS was calculated by first finding the total acreage required for the total capacity of BESS to be implemented in each year in the analysis period. The BESS footprint was estimated at 0.023 acres/MW. This fell within the range of 0.004 and 0.037 seen in research[20,21] . A 50:50 ratio of the projected market land price to an assumed concessionary land price was then multiplied by the total acreage to give the cost of the land that would be used for BESS. This figure was discounted over the years and divided by the discounted solar production to give the VOS sub-value for land use cost.

Recycling costs for the BESS were calculated by first determining the capacity to be recycled in a given year within the analysis period. This was done by offsetting the capacity implemented in each year by 10 years, which was the estimated lifetime. Once the capacity to be recycled was known for a given year, the cost to recycle it was found by multiplying the capacity by the sum of the shipping and labor costs explained in the Recycling Data subsection of the Inputs section of this report. These costs were then discounted and summed, and the result was divided by the sum of the discounted PV production over the years.

These costs were each discounted over the analysis period and divided by the total discounted solar production to give the respective VOS sub-values. The sub-values were then summed to give a final VOS value for BESS costs.

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[20] Tesla. Accessed 2022. "Select MegaPack." https://www.tesla.com/megapack/design

[21] Mortenson. Accessed 2022. "Building vs Container: Energy Storage." https://www.mortenson.com/energy-storage/building-vs-container#:~:text=Permitting%20and%20site,a%20building%20solution

Upgrade Costs

Analysis of this component looked at VOS sub-values for the cost of upgrading the maxed-out feeder versus the cost of using the BESS to defer the feeder upgrade.

The cost of upgrading the feeder from 8.64 MVA to 10.47 MVA, which was the size required to host the distributed solar capacity projected to be on the feeder by the end of the analysis period, was estimated to be around USD $6.93 million in 2022. This cost was escalated by 2% each year, meaning that in 2034, the year in which the feeder upgrade was scheduled to occur, the cost was around $8.79 million. This cost was discounted and used with the discounted solar production to give a VOS value for the Upgrade Costs component.

Calculation of Integration Costs VOS Value for Customer-owned Distributed PV Scenarios

The VOS value for the Integration Costs variable for these scenarios was calculated by summing the sub-values obtained for the BESS Costs and Upgrade Costs.

5.7.2. Utility-scale Scenarios

For the VOS analysis from the utility-scale perspective, it was assumed that utility-scale solar will be installed near the Bodden Town and Frank Sound substations, as those were located near the sites with the highest potential for solar. The approximate areas available near each substation were as follows:

Bodden Town – 686.8 acres
Frank Sound – 727.2 acres

This represented a ratio of 49% to 51% which was used to determine the distribution of utility scale solar between the two sites. The projected capacity of solar on the grid for each year of the analysis period was distributed between the two substations in this proportion. The point at which the DG capacity at each substation exceeded the total capacity of all the feeders at the substation was noted as the year in which an intervention would be needed for the integration of solar. For both substations, this happened in year 3 of the VOS analysis period (2025).

It was assumed that the intervention of choice would be construction of new 132 kV substations, including feeders, near Bodden Town and Frank Sound. This size substation was expected to host approximately 50 MW-DC of solar capacity, allowing for 100 MW of solar integration into the grid in total. This was scheduled to be implemented in year 3 (2025) in preparation for the addition of the new capacity in year 4. In year 14 (2036) the projected solar capacity on the grid was 140 MW. In order to facilitate the additional 40 MW of solar, it was assumed that two more 132 kV substations would be built, which would provide enough capacity for future expansion past the analysis period.

Other interventions that could be pursued include new feeders or substation upgrades, however those were not considered in this analysis. Additionally, it was assumed that BESS sized at 40% of the installed solar capacity would be required at each substation for smoothing of the solar generation.

BESS Costs

For the utility-scale scenarios, the costs calculated as separated VOS sub-values were:

- Cost of capacity required for voltage and frequency regulation (-)
- Cost of capacity required for spinning reserve (-)
- Avoided costs due to reduced fuel losses from genset spinning reserve operation (+)

- Opportunity cost associated with land use for BESS (-)
- Cost of removal at end-of-life (-)

Calculation of these costs followed the same methods used for the customer owned distributed PV scenarios explained previously.

The VOS for BESS costs were calculated using the same method as that in the customer-owned distributed solar scenario. The discounted costs of the BESS were each divided by the sum of the discounted overall solar production to give VOS sub-values which were then added to give a final VOS value for BESS Costs.

New Substation Costs

The average cost of a new substation, including feeders, was estimated based on CUC's historical capital expenditure on 69 kV substations, as noted in their annual reports. A cost multiplier to estimate the cost of a 132 kV substation was derived from a study done by Mondol and Jacob (2018)[22] which performed case studies on the interconnection costs for solar farms of various capacities to substations of varying sizes. These included a 40 MW farm connected to a 66 kV substation and a 50 MW farm connected to a 132 kV substation. The ratio of the total interconnection costs in these two scenarios was used as the cost multiplier for estimating the build cost of a 132 kV substation in this VOS analysis. The product of the cost multiplier and the average substation cost based on the numbers from CUC was used as an approximation of the cost of constructing a new 132 kV substation in the Cayman Islands. This cost was escalated by 2% each year to account for changes in the market.

The VOS for Substation Costs was calculated by determining the costs associated with each of the three phases of substation construction. The discounted total cost of the substations was then divided by the sum of the discounted solar production to give the VOS Substation component of the Integration Costs variable for the utility-scale scenario.

Calculation of Integration Costs **VOS Value** for Utility Scale Scenarios

Finally, the VOS values obtained for BESS Costs and Substation Costs were summed to give the final VOS value for the Integration Costs variable.

5.8. Fuel Price Volatility

This variable represents the avoided spending that CUC typically incurs to avoid price volatility and the inherent risk that is in the market. To hedge against fuel prices, CUC use a strategy known as a call option. An option is a contract which provides the buyer of the contract the right, but not the obligation, to purchase or sell a particular amount of a specific commodity (or the financial equivalent thereof) on or before a specific date or period of time. Specifically, a call option provides the buyer of a call option with a hedge against rising prices.

As an example, let's say that a utility wants to purchase a September CME/NYMEX ULSD APO call option at a strike of $1.50/gallon and a premium cost of $0.0625/gallon. Let's then say that September arrives and the fuel price for a September CME/NYMEX ULSD swap is approximately $1.46/gallon. In this case, the $1.50 call option is $0.04/gallon out-of-the-money ($1.50-$1.46=$0.04), and the utility did not hedge well. However, let's say that instead, the average fuel price in September was $1.85/gallon. In this case,

[22] Mondol, J. & Jacob, G. 2018. "Commercial Scale Solar Power Generation (5MW to 50 MW) and its Connection to Distribution Power Network in the United Kingdom". https://pure.ulster.ac.uk/ws/portalfiles/portal/76038235/JSERU_V5A4_Mondol.pdf

the call option would provide the utility with a hedging gain \$0.75/gallon (\$1.85-\$1.50= \$0.35). However, given that they paid \$0.0625/gallon for the option premium, the utility's net benefit from the option would be \$0.2875/gallon (\$0.35-\$0.0625=\$0.2875).

From this example, it is reasonable to assume that the price of the call option is essentially the cost that a utility pays to avoid rising prices and price volatility in the market. Additionally, there is a risk factor that could be included in the analysis.

So, to determine the avoided fuel price volatility from DSG, the following inputs are used:

- Discount Rate
- Solar Production [kWh]
- Average utility heat rate [Btu/kWh]
- Fuel price (split for diesel fuel and NG) [USD/MMBtu]
- Electricity generation from diesel fuel [kWh]
- Electricity generation from NG [kWh]
  - Electricity generation offset by solar production
- Heat required [MMBtu]
- Contract details
  - Barrels per contract or MMBtu per contract
  - Call option premium cost per contract [USD/contract]

For the Cayman Islands, the contract details are outlined in the table below and are based on market standards:

Barrels/contract	1,000
MMBtu/contract	5,551.36

Exhibit 32: Cayman Islands Contract Details

The number of contracts was determined by multiplying the average utility heat rate [Btu/kWh] by the solar electricity generation offsetting diesel fuel [kWh], and dividing this value by the contract amount [Btu/contract].

$$\#_{contract,n} = HR_{u,n}\ \ [Btu/kWh] \times P_{avoided\ \ diesel,n}\ \ [\$/kWh] \div 5551.36[MMBtu/contract] \times 10^{-6}$$

where

- $\#_{contract,n}$ = number of contracts for year n for diesel fuel
- $HR_{u,n}$ = average utility heat rate for year n, $[Btu/kWh]$
- $P_{avoided\ \ diesel,n}$ = avoided diesel production based on solar production for year n, [kWh]

Once the number of contracts that would be needed to hedge diesel fuel was determined for each year, the total utility cost was calculated by multiplying the discount factor by the number of contracts by the contract premium price. The contract premium prices were estimated based on historical CUC hedge data and forecasted values that were assumed to change according to diesel fuel prices.

$$C_{u,n} = D_n \times \#_{contract,n} \times Price_{contract,n} \quad [\$/contract]$$

where

- $C_{u,n}$ = avoided utility cost for year n for fuel hedging, [\$]
- D_n = discount factor for year n
- $Price_{contract,n}$ = contract premium price for year n, [\$/contract]

Finally, to get the value of solar for the fuel volatility variable, the sum of the discounted avoided utility costs for all years was divided by the sum product of the total solar production over the 30 years and the discount factor.

$$VOS_{vol} = \frac{\sum_n C_{u,n} \quad [\$]}{\sum_n (P_{s,n} \times D_n) \quad [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for fuel hedging, [\$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.9. Reliability and Resiliency

This VOS variable was calculated as the sum of two components – the avoided revenue loss to the utility and the value of lost load to the economy. For both components the projected MWh lost were calculated as explained in Section 4.2.7. Outage Data.

5.9.1. Avoided Revenue Loss

Average Weighted Tariff

An average weighted tariff was calculated based on rates for each customer class (Residential, Commercial, Large Commercial) and their respective share of historic kWh sales.

VOS Value

The projected MWh lost were multiplied by the average weighted tariff to estimate the revenue loss to the utility due to projected outages from 2022 to 2052. This revenue loss was called the utility cost. The utility cost for each year was discounted, and these discounted values were summed to give a Utility Present Value. Similarly, the PV production for each year was discounted and the values summed. The Utility Present Value was then divided by the sum of the discounted PV production over the years to give the VOS value for avoided revenue loss.

5.9.2. Value of Lost Load (VOLL)

This methodology followed that outlined by Cambridge Economic Policy Associates (CEPA)[23]. The approach considered the value of lost load in two customer classes – residential and commercial. The residential aspect was based on the amount of household expenditure that was dependent on electricity while the commercial aspect looked at the value added to the economy.

Commercial Value

The nominal Gross Value Added (GVA) to the economy over the years 2016 to 2021 were obtained in 2020 KYD from the Cayman Islands National Economic Accounts. The kWh sales to commercial customers for the same years were obtained from CUC data. The GVA per kWh was calculated for each of the 5 years, and the average value determined and used as the commercial VOLL.

Residential Value

Average Leisure Hours per Day

Assumptions were made that 10 out of the 24 hours in 1 day are reserved for personal care activities of sleeping, washing and eating, and that the average working day is 8 hours. This leaves 6 leisure hours per working day, and 14 leisure hours per non-working day.

The number of non-working days in a year were calculated by subtracting the number of working days from the 365 days in the year. Taking into account Cayman's 11 public holidays, and assuming weekends as non-working days, this left a total of 249 working days, and 116 non-working days per year.

A value of 8.54 average leisure hours per day was then calculated from the following expression:

$$\frac{(\text{Avg leisure hours per working day} \times \text{ Working days per yr}) + (\text{Avg leisure hours per nonworking day} \times \text{ Nonworking days per yr})}{365}$$

Average Employed Leisure Value per Day

The yearly median income for 2017 was obtained from the Cayman Islands Occupational Survey and escalated and adjusted for inflation to obtain an estimate for the yearly median income in 2020 KYD. This was then used to calculate the median income per working day and then per hour of each working day. The resulting value was multiplied by the average leisure hours per day to give the average employed leisure value per day.

Electricity-Dependent Leisure Value

It was assumed that 50% of leisure activities were dependent on electricity. This figure was called the substitutability factor (s.f.). Another assumption was that non-employed persons valued 1 hour of leisure 50% less than those who were employed, called the non-employment coefficient. The number of non-employed persons were calculated by subtracting the number of employed persons from the total Cayman population in 2020.

The electricity-dependent leisure value was then calculated using the following expression:

$$(\text{No. employed persons} \times \text{ avg employed leisure value per day} \times \text{s.f.}) + (\text{No. non} - \text{employed persons} \times \text{avg employed leisure value per day} \times \text{s.f.} \times \text{non} - \text{employment coeff.})$$

[23] Heather, Lewis, Michell, Daniel, & Glevey, Will. 2018. "Study on the Value of Lost Load of Electricity Supply in Europe - Acer". https://extranet.acer.europa.eu/Events/Workshop-on-the-estimation-of-the-cost-of-disruption-of-gas-supply-CoDG-and-the-value-of-lost-load-in-power-supply-systems-VoLL-in-Europe/Documents/CEPAPresentation_VoLLWorkshop.pdf

The household electricity-dependent electricity leisure value was then calculated by dividing the electricity-dependent leisure value by the residential electricity sales in 2020.

5.9.3. VOS Value

The commercial VOLL and the household electricity-dependent electricity leisure value were adjusted to 2021 KYD/kWh using Consumer Price Index (CPI) data. These values were then inflated to give 2022 KYD/kWh figures and converted to USD/kWh. They were then multiplied by the projected MWh lost and the products summed to give an Economic Value Lost per kWh for each year of the analysis period. This was the utility cost. The utility costs for each year were discounted and then summed to give a utility present value which was then divided by the sum of the discounted PV production to give the VOS Value for VOLL. As mentioned earlier this VOS value was added to that of the Avoided Revenue Loss to give the VOS value for the Reliability and Resiliency variable.

5.10. Market Price Response

The market price response variables attempt to explore how the addition of distributed solar, especially at higher penetrations, and utility scale solar can affect the market price of electricity. The merit order effect in energy markets describes the lowering of power prices at the electricity exchange due to an increased supply of renewable energies. The logic is that cheaper solar generation will be able to offset more expensive conventional generators that have high fuels cost and variable O&M costs, and therefore lower clearing prices will be achieved in the electricity market. Thus, by increasing the amount of renewables on the grid and offsetting fossil fuel generation, a lower electricity price is set. This is shown clearly in Exhibit 33.

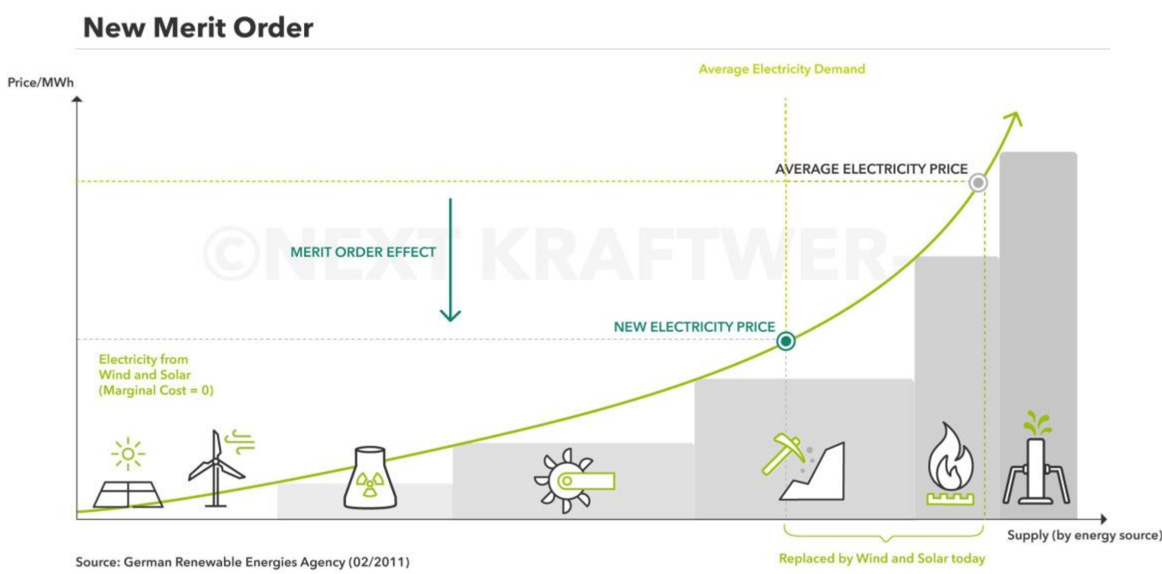

Exhibit 33: Merit order effect in the electricity market

While the Cayman Islands does not have a competitive electricity market with day ahead bidding and a market clearing price, the merit order effect is still relevant. Even with a regulator-set electricity price, the price will reflect the operation costs of the active generators in the grid. Therefore, the more solar, wind and battery generation in the market, the lower the market price will be since the operation and fuel costs are small compared to fossil fuel gensets.

To determine the market price response of solar, a model was developed in PLEXOS. PLEXOS is an energy modeling and forecasting software platform. Its powerful simulation engine can analyze regional and nodal energy models for long term planning. A single-line diagram of the Cayman Islands power system was used as a guideline for modeling a simplified version of the system in PLEXOS. In the simplified model, there are 7 nodes, and all existing generators are integrated into the system at these nodes. The future generation capacity (according to the modified 2017 IRP), and distributed generators are also integrated and defined with relevant properties such as project start date, max capacity, VOM costs, FOM costs, build costs, heat rates (if applicable), etc. Additionally, the forecasted demand profile is included as well as a typical solar and wind profile for the Cayman Islands. Once the system was defined the team created three scenarios to run over a 30-year horizon for comparison:

1. System with DSG and utility scale solar
2. System without DSG but with utility scale solar
3. Base Case- System without DSG and without utility (replaced by equivalent NG capacity)

The model execution provides a range of output variables that can be analyzed. For the market response variable, the team extracted the *Region Price* variable for each scenario. The region price is the simulated electricity market price calculated by the PLEXOS algorithm that considers all system costs and generation during the 30-year period. The difference in region prices was compared between scenario 1 and scenario 2 to understand the impact of DSG and between scenario 2 and the Base scenario (3) to understand the impact of prioritizing utility scale solar over NG. The difference in region price between the scenarios gave a value in USD per kWh that captures the effect that solar on the market price. This price difference was multiplied by the total discounted solar production to get the utility value.

$$C_{u,n} = D_n \times P_{s,n} \ \ [kWh] \times (Price_{base,n} - \ Price_{utility,n}) \ \ [\$/kWh]$$
$$C_{u,n} = D_n \times P_{s,n} \ \ [kWh] \times (Price_{utility,n} - \ Price_{DSG}) \ \ [\$/kWh]$$

where

- $C_{u,n}$ = avoided utility cost for year n for market price changes, [\$]
- D_n = discount factor for year n
- $P_{s,n}$= solar production for year n, $[kWh]$
- $Price_{base,n}$ = electricity market price in system without DSG and without utility for year n, $[\$/kWh]$
- $Price_{DSG,n}$ = electricity market price in system with distributed and utility solar for year n, $[\$/kWh]$
- $Price_{utility,n}$ = electricity market price in system with just utility solar for year n, $[\$/kWh]$

Then to get the value of solar for the market price change, the sum of the discounted avoided utility costs for all years was divided by the sum product of the total solar production over the 30 years and the discount factor.

$$VOS_{mrkt\ \ price} = \frac{\sum_n C_{u,n}\ \ [\$]}{\sum_n (P_{s,n} \times D_n)\ \ [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for market price changes, [\$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.11. Net Carbon Emissions

This variable considered both the avoided cost of carbon emissions from replacement of fossil fuel generation with solar, and the lifecycle emissions associated with solar PV due to manufacturing and end-of-life management processes. Two VOS sub-values were calculated to account for each of these factors and then summed to give the final VOS value.

A weighted carbon dioxide emissions factor (kgCO_2 per MMBTU) was calculated for each year in the analysis period based on the share of generation from natural gas and from diesel. This weighted factor was then multiplied by the cost of carbon obtained from the UK Shadow Pricing of Carbon documentation as explained in the Inputs section ($/tonne$CO_2$) and divided by 1000 to give a CO_2 cost in $/BTU.

The utility cost was then calculated by multiplying the CO_2 cost for each year by the corresponding solar-weighted heat rate. As with the previously discussed methodologies, the utility cost for each year was discounted and then all summed to give a utility present value. The utility present value was then divided by the sum of the discounted solar PV production over the years to give the first VOS sub-value.

The solar PV factor of 46 gCO_2e/kWh was obtained from NREL. To obtain a value that represented only carbon emissions, the average ratio of the weighted carbon dioxide emissions factor to the weighted carbon dioxide equivalent factor for generation throughout the years of the analysis period was calculated. The average ratio was 99% CO_2 to 1% CO_2e. This ratio was applied to the solar PV emissions factor and used to determine the CO_2 emissions factor in gCO_2/kWh. The factor was divided by 1000 and then multiplied by the annual PV production to give the total annual emissions in kgCO_2e. The result was then multiplied by the corresponding cost of carbon ($/tonne$CO_2$) and divided by 1000 to give the utility cost ($) in each year. The utility cost was then discounted and divided by the sum of the discounted solar PV production over the years to give the second VOS sub-value.

5.12. Other Pollutants

This variable was also calculated using two VOS sub-values for avoided pollutants and lifecycle pollutants from solar PV.

The first part of the methodology was identical to that of Carbon Emissions, except that a weighted carbon dioxide equivalent factor (kgCO_2e /MMBTU) was used in place of the carbon dioxide factor to account for methane and nitrous oxide emissions from both natural gas and diesel generation as they occurred during the analysis period. The rest of the analysis was carried out in the same way as described above to give the first sub-value.

The second part of the methodology was also identical to that of Carbon Emissions except that the 1% CO_2e ratio was applied to the lifecycle emissions factor to give the CO_2e emissions factor (gCO_2e/kWh) for solar PV. The rest of the analysis followed the method described for the second sub-value of the Carbon Emissions variable where the utility cost was found by multiplying the CO_2e emissions factor by the kWh produced over the years and the result was discounted and divided by the discounted solar production. The resulting value was added to the value obtained in the first part of this methodology to give the final VOS value for this variable.

5.13. Net Water Use

This variable investigates how solar generation can reduce the overall consumption of water in the power sector. It is calculated by determining the reduced volume of water when offsetting fossil fuel generators. A literature review was conducted to determine the water usage of various technologies. The following values were used for water consumption [L/MWh]:

Generation Technology	Water Usage [L/MWh]
Solar	300
NG	750
Diesel	3,100

Exhibit 34: Water usage values by generation technology

The consumption of water from solar, which included water needed to wash the panels, was subtracted from the consumption of water when using diesel from 2022-2038 and from the consumption of water when using NG from 2039-2052. This resulted in "water consumption avoided" in L/MWh over the 30-year period, which was multiplied by the total solar production [kWh] to get the avoided amount of water.

$$W_{avoided,n} = (WC_u - WC_s)\ [L/MWh] \times P_{s,n}\ \ [kWh] \times 10^{-3}$$

where

- $W_{avoided,n}$ = avoided water for year n, $[Liters]$
- WC_u = utility water consumption for either NG or diesel, $[L/MWh]$
- WC_s = solar water consumption = 300 $[L/MWh]$
- $P_{s,n}$= solar production for year n, $[kWh]$

The price of water was obtained from the Cayman islands water authority for public authorities. The utility price, which represents the societal cost of water acquisition, is then determined by multiplying the water price in [USD/m3] by the avoided volume of water [m^3].

$$C_{u,n} = D_n \times W_{avoided,n} \ \ [L] \times Price_{w,n} \ \ [\$/m^3] \times 10^{-3}$$

where

- $C_{u,n}$ = avoided utility cost for year n for avoided water consumption, [$]
- $W_{avoided,n}$ = avoided water for year n, $[Liters]$
- $Price_{w,n}$ = utility price of water for year n, [$/$m^3$]

The final value of solar for the avoided cost of water is then calculated as follows:

$$VOS_{water} = \frac{\sum_n C_{u,n} \ \ [\$]}{\sum_n (P_{s,n} \times D_n) \ \ [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for avoided water consumption, [$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.14. Avoided Land Impact

This variable explores how solar can avoid the land impacts associated with fossil fuel use. This required the team to understand the land impact of the offset fossil fuels from a life-cycle assessment- meaning that it doesn't just account for the land needed for the energy generation but also the land needed for mining the materials for construction, the fuel inputs, decommissioning and waste handling. Data was taken from United Nations data sources and the land use for relevant technologies is summarized in the table below in m^2/MWh:

Technology	Land Impact Value [m^2/MWh]
DSG Solar	1.2
NG	1.3
Diesel	21

Exhibit 35: Land impact value by generation technology

The cost of land for mining materials was assumed to be the average cost of land globally- which is roughly 3,000 USD per acre. Thus, the land use of NG or diesel [acre per kWh] was multiplied by the offset NG or diesel generation [kWh] and the land cost [USD per acre] to get the utility cost in USD. Finally, the additional land impact from solar for mining the materials needed for the panels and racking systems, the decommissioning and waste handling was subtracted from the utility cost.

$$C_{u,n} = D_n \times [3,000 \ \ \$/acre \times ((OP_{NG,n} \ [kWh] \times 1.3 \ [m^2/MWh])) + ((OP_{d,n} \ [kWh] \times 21 \ [m^2/MWh]))$$

where

- $C_{u,n}$ = avoided cost for year n for avoided land impact, [$]
- D_n = discount factor for year n
- $OP_{NG,n}$ = offset NG production for year n from solar, $[kWh]$
- $OP_{d,n}$ = offset diesel production for year n from solar, $[kWh]$

The process was identical for utility scale solar since this variable is just concerned with the offset land impacts from fossil fuel. The final value of solar was calculated with the following expression:

$$VOS_{land} = \frac{\sum_n C_{u,n} \ \ [\$]}{\sum_n (P_{s,n} \times D_n) \ \ [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for avoided land impact, [$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.15. Land Use

This variable assesses how solar competes for land availability and impacts land, requiring information about the additional land impact of both rooftop and grounded mounted solar. The data was taken from the same source as above (See Exhibit 26). For rooftop solar the land impact is much smaller, since it requires no additional acreage on island- in other words, its only impact is from the land needed to mine and construct the materials needed for the solar system, and the land impact associated with decommissioning and waste disposal of the solar system. With this assumption- the average price of land is used – 3,000 USD/acre. The calculation is as follows:

$$C_{u,n} = D_n \times \underbrace{[3,000 \ \ \$/acre \times (1.2 \ [m^2/MWh]) \times (P_{s,n} \ [kWh])]}_{\text{Cost of land for mining, materials, decommissioning, waste handling}}$$

where

- $C_{u,n}$ = additional cost for year n for land use during generation, [$]
- D_n = discount factor for year n
- $P_{s,n}$= solar production for year n, $[kWh]$

The final value of solar for the additional land impact of distributed solar is calculated in a similar manner for distributed solar, since distributed solar is incorporated onto previously existing building, therefore requiring no local land. The final VOS for distributed solar land impacts was based on life-cycle assessments, accounting for the land used for the mining of materials used for its construction, fuel inputs, decommissioning, and handling of the waste. Therefore, the final VOS is calculated as follows:

$$VOS_{land_1} = \frac{\sum_n C_{u,n} \;\; [\$]}{\sum_n (P_{s,n} \times D_n) \;\; [kWh]}$$

where

- $C_{u,n}$ = additional cost for year n for land use during distributed generation, [$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

However, for the utility scale solar, the land impact is a bit larger since these solar farms require additional land space (unless used like a car canopy or in an unused quarry, although these dual use systems require additional costs as well).Therefore, the cost of the local land needed to construct the utility solar farm needs to be considered in addition to the land impact for materials, commissioning, and disposal of the solar panels. The on-island land that is required for the solar farm was based on a market assessment that forecasted USD per acre on average for land costs from 2022-2052. Additionally, the solar PV land use value of 3.5 acres per MW was used in this assessment when determining land amounts. The first 55 MW of utility solar was assumed to take advantage of the cheaper 190 acres of Crownland. The following 57MW was assumed to take advantage of the cheaper 200 acres of available waterway. Again, the additional costs of floating solar farms, which could be significant, and the negative impact on the resiliency and reliability were not accounted for in this study. Both the Crown land and waterways has an associated cost of 5,000 USD/acre/year based on relevant crown lease rates in the region. Thus, the calculation for the utility scale solar land impact cost was as follows:

$$C_{u,n} = D_n \times \underbrace{[3,000 \;\; \$/acre \times (1.2\, [m^2/MWh]) \times (P_{s,n}\, [kWh])]}_{\text{Cost of land for mining, materials, decommissioning, waste handling}} + \underbrace{[Price_{land,n} \;\; \$/acre] \times (V_{s\ new,n} \;\; [MW] \times 3.5 \;\; [acres/MW])}_{\text{Cost of local land for solar farm}}$$

where

- $C_{u,n}$ = additional cost for year n for land use during generation, [$]
- D_n = discount factor for year n
- $P_{s,n}$= solar production for year n, $[kWh]$
- $Price_{land,n}$ = cost of land for year n
- $V_{s\ new,n}$= new build utility solar capacity for year n, $[kW]$

The final component of the Land Use variable for the utility scale scenarios considered the costs of recycling the solar panels at the end of their lifetime. The capacity of solar to be recycled in a given year within the analysis period was determined by simply offsetting the capacity implemented in each year by 25 years. Once the capacity to be recycled was known for a given year, the cost to recycle it was found by multiplying the capacity by the sum of the shipping and labor costs explained in the Recycling Data subsection of the Inputs section of this report. These costs were then discounted and summed, and the result was divided by the sum of the discounted PV production over the years. The result of this calculation was then added to that of the previous calculation to give the VOS value for the Land Use variable.

The final value of solar for additional utility scale solar land impact was calculated in the same manner as the integration costs VOS. The calculation needed to consider the full life cycle of the solar system since the cost to purchase and use the land will enable the solar farm to generate electricity for its entire lifetime, not just for the time horizon of the analysis. Therefore, the solar production captured needed to extend out until the last year of solar generation from the last built utility farm, rather than just the end of the analysis horizon (2052). The VOS was determined as follows:

$$VOS_{land_{1,utility}} = \frac{\sum_n C_{u,n} \ \ [\$]}{\sum_{n,lifetime\ of\ last\ solar}(P_{s,n} \times D_n) \ \ [kWh]}$$

where

- $C_{u,n}$ = avoided utility cost for year n for additional land use, [\$]
- $P_{s,n}$= solar production for year n, for entire lifetime of all solar generators $[kWh]$
- D_n = discount factor for year n

Specifically for the Cayman Islands study, the last utility scale solar farms are commissioned during 2030 to begin generation in 2031. Therefore, all kWh's produced during the 25-year lifetime of these plants, out until 2056 was included in the VOS determination.

5.16. Net Economic Development

This variable measures the economic impact generated in the Cayman Islands because of new-build solar. Data was taken from NREL's report on Energy, Economic, and Environmental Benefits of solar initiatives in the US since these values not only consider the economic impact from new build solar, but also the lost economic impact from developing natural gas to substitute for the solar. Therefore, the value is a net economic development value. The report considers the benefits coming from construction, O&M and R&D but for the Cayman context, only the construction and O&M benefits will be realized since the solar panels will be imported from abroad. The economic impacts from the report are summarized below in Exhibit 36.

	USD Added for 10 MW	USD per MW
Construction Income	$ 2,901,796,000	$ 290,179.60/MW
O&M Output	$ 518,614,000	$ 51861.4 /MW
O&M Personal Income	$ 7,221,880,000	$ 722,188.00/MW
	Total:	$ 1,064,229 / MW

Exhibit 36: Summary of economic impacts from solar PV

These values were validated by stakeholder inputs, which estimated that there are roughly 20 full time jobs created in the Cayman Islands per MW of solar and the average salary on the Cayman Islands for an engineer is around 63,000 KYD. This equates to about USD 1,497,000 per MW just for the solar impact. However, since the NREL value of USD 1,064,229 per MW considers the lost economic impact from natural gas development, it was deemed to be more comprehensive and more fair.

To get the value added, the overall economic value of USD 1,064,229 per MW was multiplied by the new build capacity [MW] each year and the discount rate:

$$V_n = D_n \times V_{n,new} \ \ [kW] \times 1,064,229 \ \ [\$/kW]$$

where

- V_n = value added for year n for new build solar, [\$]
- D_n = discount factor for year n
- $V_{n,new}$ = new build solar capacity for year n, $[kW]$

Finally, the value of solar was calculated by dividing the sum of the added value for all years by the sum product of the total solar production over the 30 years and the discount factor.

$$VOS_{econ} = \frac{\sum_n V_n \ \ [\$]}{\sum_n (P_{s,n} \times D_n) \ \ [kWh]}$$

where

- V_n = value added for year n for new build solar, [\$]
- $P_{s,n}$= solar production for year n, $[kWh]$
- D_n = discount factor for year n

5.17. Final VOS Calculations

The final value of solar was determined by simply summing all of the individual values of solar for each variable as seen below.

$$VOS_{final} = \sum (VOS_{energy} + VOS_{FOM} + ... + VOS_{land} + VOS_{econ})$$

6. Net Installed Costs

The net installed costs of solar were not included in the calculation of the final VOS, but were still analyzed to provide further context to the study. The overall cost (or benefit) derived by customers from installing solar, reducing payment to the utility for electricity and receiving credit for energy supplied to the grid was calculated.

6.1. Installed Costs

Estimates for the installed cost of solar in the Cayman Islands were obtained from the Cayman Renewable Energy Association. These were as follows:

- Residential: 3-3.5 $KYD/W
- Commercial: 2-2.5 $KYD/W

The average values of 3.25 and 2.25 were used for further analysis. The projected changes in installed cost over the analysis period were modelled after the changes in projected small-scale residential (<1 MW) solar Levelized Cost of Energy (LCOE) values obtained from NREL's Annual Technology Baseline.
The ratio of residential to commercial (both large and general) customers were obtained from historical data on annual new connections in the distributed renewable generation programs. These ratios were used to weight the new PV capacity in each year of the analysis period among the categories. The weights were also applied to the PV production from the new capacity.

The installed costs were then multiplied by the corresponding weighted new PV capacity to give the total installed costs for residential and commercial customers each year.

6.2. Avoided Electricity Costs

Projected annual values for the base electricity rate for each customer class were multiplied by the weighted PV production from new capacity each year to give an estimate of the amount that prosumers would avoid paying to the utility, assuming they self-consumed or stored all of the energy produced. The avoided amount for general commercial and large commercial customers were added to get a total avoided amount for commercial customers.

The amount avoided by the customers was subtracted from the installed costs to give the net cost to residential and commercial customers. These were then discounted and summed over all the years of the analysis period to give present values for the two categories of customer. The two present values were then summed and divided by the discounted PV production from new capacity to give a value for this variable.

6.3. Administrative Costs

Customers who participate in DG programs are required to pay a one-time 250 KYD interconnection fee to cover administrative costs. This figure was multiplied by the number of new customers each year to give annual values for the administrative costs.

6.4. Net Installed Costs

The net installed costs were calculated for residential and commercial customers by subtracting the cost of the installed system and administrative costs from the avoided electricity base rate payment avoided each year.

6.5. Credits for Energy Supplied

Thus far, the analysis has not accounted for kWh sent back to the grid by customers and has instead assumed that customers consume or store all of the energy produced by their solar systems. In reality, there would be some offset of electricity purchased from the grid, but not completely, as customers without storage, for example, would rely on the grid at night.

CUC currently offers credits for energy supplied to the grid through two programs, - the Consumer Owned Renewable Energy (CORE) programme and the Distributed Energy Resources (DER) programme. In the CORE program, prosumers are credited based on the size of their system as follows:

- 0-5 kW: 0.175 KYD/kWh
- 5-10 kW: 0.15 KYD/kWh
- 0-100 kW: 0.28 KYD/kWh (public sector only)

In the DER program, prosumers receive the lesser of two options:

1. The comparable energy purchase rate of the most recent Renewable Energy Power Purchase Agreement ("RE PPA"): 0.14592 KYD/kWh (as of Nov 1st, 2021) or,
2. The current Excess Energy Rate per the Demand Rates Terms of Service (as of June 1, 2018 $0.00264/kWh), plus the current Fuel Charge rate, plus the current Government Fuel Duty Rate, plus the current Renewable Energy Charge rate.

For the purposes of this analysis, the RE PPA was used as a conservative estimate of the credit rate that DER prosumers would receive.

An average value for the kWh supplied per kW of solar capacity installed on the grid was calculated based on historic data obtained from CUC. Additionally, the ratio of kWh supplied from the CORE program to those supplied from the DER program (CORE% to DER%) was estimated from data for the years 2019 to 2021. The average ratio from the 2 most recent years was used going forward.

DER Prosumers

For each year in the analysis period, the product of the RE PPA, the DER%, the kWh supplied per kW value and the projected new capacity for the year was calculated to give the total DER credit received by customers in the respective year.

$$DER\ Credit = RE\ PPA \times DER\% \times kWh\ supplied\ per\ kW \times New\ Capacity$$

CORE Prosumers

For CORE prosumers, the kWh supplied by each system size category was first calculated for each year. This was done by multiplying the CORE% of historical kWh supplied by the projected fraction of customers in each category and finally multiplying by the projected solar capacity for that year and the kWh supplied per kW value. For example, for the kWh supplied by systems rated 0-5 kW in a given year, the calculation was as follows:

$$kWh\ supplied_{0-5kW} = CORE\% \times \frac{\#\ customers\ 0-5\ kW}{\#\ new\ customers\ for\ the\ year} \times New\ Solar\ Capacity \times kWh\ supplied\ per\ kW$$

Once the kWh supplied by each category of customer was obtained, the values were multiplied by the corresponding credit rate and the products summed to give the total CORE Credit to customers each year.

6.6. Overall Benefits/Costs to Customers

This was calculated by summing the net costs to residential and commercial customers, DER credit to prosumers and CORE credit to prosumers.

6.7. Savings

Customer savings on electricity were calculated by subtracting the product of the kWh produced and the solar LCOE, obtained from NREL, from the amount customers would otherwise pay through the utility's base rate.

7. VOS Studies Overview

A meta-analysis was carried out on value of solar assessments completed in other jurisdictions to provide context and comparison for the Cayman Islands VOS assessment. Fifteen studies were reviewed, including the ICF Report, *Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar (2018).* Additionally, the meta-analysis from the Interstate Renewable Energy Council (IREC) guidebook[24] on calculating the benefits and costs of distributed solar generation was reviewed and its recommendations considered.

Number	Study	Jurisdiction
1.	Minnesota Value of Solar: Methodology	Minnesota
2.	Maine Distributed Solar Valuation Study	Maine
3.	Valuation of Solar + Storage in Hawaii: Methodology	Hawaii
4.	The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.	Arkansas
5.	Estimating the Impact of Net Metering on LPSC (Louisiana Public Service Commission) Jurisdictional Ratepayers	Louisiana
6.	Net Metering in Mississippi: Costs, Benefits, and Policy Considerations.	Mississippi
7.	Nevada Net Energy Metering Impacts Evaluation 2016 Update	Nevada
8.	South Carolina Act 236: Cost Shift and Cost of Service Analysis	South Carolina
9.	Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014	Vermont
10.	Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting	Washington, D.C.
11.	A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia	Georgia
12.	Pacific Gas and Electric (PGE) Distributed Solar Valuation Methodology	Oregon
13.	Value of Solar in Utah	Utah
14.	Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B.	California
15.	Order Establishing the Benefit Cost Analysis Framework. Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.	New York

Exhibit 37: Value of Solar studies reviewed during meta-analysis

[24] Interstate Renewable Energy Council (IREC) & Rábago Energy LLC. 2013. "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation". https://irecusa.org/resources/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/

As highlighted in Exhibit 38 below, 18 variables were considered in the 15 studies, with each variable categorized as having utility system impacts, or impacts related to generation, transmission, distribution, customers, and society.

All studies included or discussed an evaluation of Avoided Energy Costs, Avoided Generation Capacity, and Avoided Transmission Capacity, while fourteen included Avoided Distribution Capacity among the VOS variables. These variables are most prominent and relatively straightforward to assign a value of solar value because increased solar generation directly impacts a utility's energy costs, and generation, transmission, and infrastructure costs and operations.

Other variables which were included in more than half the studies included: Integration costs (13), System Line Losses (11), Ancillary Services (spinning reserve) (10), Avoided Fuel Hedging (9), Avoided Environmental Compliance (9), Avoided *Other* Air Pollutants (9), Avoided Carbon Emissions (8), and Ancillary Services (8). Overall, the exact variables included in each study differed depending on the characteristics of the energy landscape in each jurisdiction, as well as the mandate of the value of solar assessment.

Item #	Value of Solar Variable	Benefit (+) or Cost(-)	Arkansas	Nevada	Louisiana	South Carolina	Mississipi	Vermont	Washington DC	Georgia	Hawaii	Maine	Oregon	Minnesota	Utah	New York	California	Total # of Inclusions	Cayman Islands
Direct Utility Impact (Energy/Grid)																			
Generation																			
1	Avoided Energy Costs (fuel & O&M)	+	I	I	I	I	I	I	I	D	D	I	D	I	I	I	D	15	I
2	Avoided Generation Capacity	+	I	I	I	I	I	I	I	D	D	I	D	D	I	I	D	15	I
3	Avoided Reserve Capacity	+		I		I	D		D	D	D	D	D			D	D	10	I
Transmission																			
4	Avoided Transmission Capacity	+	I	I	I	I	I	I	I	D	D	I	D	D	I	D	D	15	I
5	System Losses	+	I	I		I	I	I	I	D			D		I	D	D	11	I
6	Ancillary Services: Distribution Voltage and Power Quality	+/-								D	D	D	D			D	D	6	I
Distribution																			
7	Avoided Distribution Capacity	+	I	I	I	I	I	I	I		D	D	D	D	I	D	D	14	I
8	Integration Costs	-	I	I	I	I	D		I	D	D	I	D	D		D	D	13	I
Risk Impact																			
Utility Operations																			
9	Reliability and Resiliency Risk	+	D				D		D							D	D	5	I
10	Fuel Price Volatility/Hedging	+	I			I	I		I		D	I	D	I	I			9	I
11	Market Price Response	+	I					I	I		D	I				D		6	I
Social Impacts																			
Environmental																			
12	Carbon Emissions	+	I					I	I		D	I		D		D	D	8	I
13	Other Air Pollutants	+	I	I			D		D		D	I		D		D	D	9	I
14	Avoided Land Impact	+/-	**	**	**	**	**	**	**	**	**	**	**	**	**	**	**	**	I
15	Water	+	**	**	**	**	**	**	**	**	**	**	**	**	**	**	**	**	I
Economic																			
16	Land Availability/Use	-	**	**	**	**	**	**	**	**	**	**	**	**	**	**	**	**	I
17	Economic Development	+	I				D		D									3	I
Other Impacts																			
18	Avoided Environmental Compliance	+	I	I			D		D		D	D		D		D	D	9	
19	Program and Administrative Costs	-		I	I	I	I	I	D							D		7	
20	Distribution O&M	+/-	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*
21	Lost Utility Revenues/Equity	-	I	I	I	I	I	I								D		7	
22	Customer Installed Net Costs	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

Key: I = Included/individually quantified : D = Discussed/quantified in other categories : Blank = Not Considered

* - Included under integration costs.

** - Variables not included in the 2018 study but were unique to, or have a material impact in the Cayman Islands' context.

n/a - typically included in cost-benefit analyses and not "value" of solar. This relates to cost borne by the owner and not an added or avoided cost/value.

Exhibit 38: Overview of variables in VOS studies from meta-analysis

In the context of the Cayman Islands, most of the variables from the meta-analysis were considered applicable for inclusion in the Cayman Value of Solar Study, barring a few notable exceptions, and a couple additional inclusions. Additionally, a levelized cost approach on a per variable basis was used.

Variables excluded in Cayman VOS relative to meta-analysis

The Cayman VOS study did not include an evaluation of:

1. **Avoided Environmental Compliance:** This value category reflects the avoided cost of complying with Governmental environmental regulations. This could include the compliance costs of either existing or anticipated carbon emissions standards or standards related to other criteria pollutants. The NEP established a high peak GHG emissions not to exceed 2014 per capita emissions levels (approx. 12.3 tCO2e). CUC designed an Environmental Management System (EMS) to meet International Standardization Organization (ISO) 14001, which specifies the requirements organizations can pursue to enhance their environmental performance.[25] As part of CUC's EMS, they created an environmental management policy to specify the organization's commitments to operate in an environmentally responsible manner. The utility has taken important steps to limit environmental impacts from its operations, however it is not mandated to be compliant to any environmental standards monitored or governed by another organization of authority. As a result, avoided environmental compliance is not applicable as a variable in the Cayman VOS analysis.
2. **Net Installed Costs:** Net installed costs are typically included in Solar Cost-Benefit Studies and not Value of Solar (VOS) Studies given that the cost of generation is borne by the distributed energy resource generator and not the utility or consumer. Rather, the VOS study considers the net benefit or cost derived from the installing solar or generated from the Net Installed Costs.
3. **Program and Administrative Costs:** An assessment of the net costs and benefits to customers, as highlighted in Section 6, considers the administrative costs associated with the CORE and DER programs in the Cayman Islands. This was considered as part of an overall assessment of benefits/costs of the programs to customers. However, the overall assessment was left out of the VOS analysis since it included direct costs associated with the installation of solar PV systems, and the VOS assessment considers the Value of Solar beyond the direct costs of the solar PV systems and any associated programs.
4. **Distribution Operations and Maintenance (O&M)**: This category represents either a cost or a benefit. It generally reflects any increase or decrease in O&M costs associated with utility investments in distribution assets and infrastructure services as a result of deploying distributed solar on the distribution system. The negative values for distribution O&M were included as part of integration costs. Due to the low likelihood that distributed solar will have a significant impact on distributed O&M and the difficulty in measuring this benefit, this assessment was not included.
5. **Lost Utility Revenues:** Lost revenues are the result of distributed renewable generation customers paying smaller electric bills and reduced customer loads. As more customers rely on renewable energy production for their consumption and utilities lose revenues this will create upward pressure on utility rates. As a result, remaining utility customers may incur higher bills to ensure utility viability. This can create equity and fairness challenges. Given that the current regulatory environment uses allows for capacity charges to CORE prosumers along with the existing renewable energy charge to all consumers, while passing the fuel savings to the full customer base, CUC has been able to maintain full cost recovery. As such, this variable was considered, but not included. Given the planned increases in distributed energy resource generation, OfReg and CUC should consider additional tariff regimes to increase the tariff

[25] CUC. "CUC and the Environment." https://www.cuc-cayman.com/environment-safety/the-environment/

versatility and cost recoverability mechanisms discussed in Section 10.1 [Tariff Review] to ensure adequate cost recovery and an equitable cost distribution is achieved.

Variables included in Cayman VOS Analysis, but not included in meta-analysis

The following variables were included in the Cayman VOS analysis, taking into consideration factors that are most pertinent in the Cayman Islands as it relates to the uptake and value of solar PV. These factors include:

1. **Avoided Land Impacts:** More than 30% of the habitats in the Cayman Islands consists of mangrove forests,[26] which forms an ecosystem crucial to bird and marine life in the country. The VOS analysis sought to measure the ecosystem impacts associated with increased solar uptake in the Cayman Islands, particularly the impact that reduced pollutants could have on habitats that may otherwise have been affected burning fossil fuels or potential spillages. Additionally, the lifecycle impacts from solar PV and battery storage were also considered in the analysis.
2. **Land Availability/Use:** With an area of only 102 square miles, land is a premium asset in the Cayman Islands. As a result, the use of land for distributed or utility-scale solar installations has an opportunity cost. Therefore, it was important to consider how land availability relative to the projected solar capacity affects the value of solar. In addition, as demand for land increases, so will the land values/costs. This is especially relevant since there are other competing uses of land in the Cayman Islands. The variable also accounted for the possibility of using Crown land, waterways, or previously built environments like a car port.
3. **Net Water Impacts:** Water is both a scarce and precious resource in many countries, particularly in the Cayman Islands. As a result, the VOS analysis investigated the net avoided water impacts associated with the uptake of solar PV in the country.

[26] UNESCO. 2022. "Mangrove ecosystems in Caribbean SIDS: Cayman Islands." https://www.unesco.org/en/articles/mangrove-ecosystems-caribbean-sids-cayman-islands

8. VOS Analysis Results and Discussion

The numerical results obtained in the VOS study are presented for each variable for both distributed solar and utility scale solar, along with the percentage contribution to the total VOS in Exhibit 39. The exhibit enables one to clearly compare utility and distributed solar against one another and view the relative contributions of each variable in numerical form. Exhibit 40 presents the same information in Cayman dollars.

Direct Utility Impact (Energy/Grid)		**Distributed VOS [USD/kWh]**	Percentage of Total VOS	**Utility VOS [USD/kWh]**	Percentage of Total VOS
1.	Net avoided Energy Costs	0.171	59%	0.157	61%
2.	System Losses	0.005	2%	0.000	0%
3.	Net avoided Generation Capacity	0.027	9%	0.042	16%
4.	Avoided Transmission Capacity	0.001	0%	0.000	0%
5.	Avoided Distribution Capacity	0.008	3%	0.000	0%
6.	Avoided Reserve Capacity	0.009	3%	0.015	6%
7.	Integration Costs	-0.0023	-1%	-0.033	-13%
	Total for Impact:	0.271	0.219		0.182
Risk Impact					
8.	Fuel Price Volatility	0.004	1%	0.002	1%
9.	Reliability and Resiliency	0.008	3%	0.003	1%
10.	Market Price Response	0.000	0%	0.019	7%
	Total for Impact:	0.013	0.012		0.024
Environmental/Economic Impact					
11.	Net Carbon Emissions	0.028	9%	0.026	10%
12.	Other pollutants	0.000	0%	0.000	0%
13.	Net Water Use	0.007	2%	0.005	2%
14.	Avoided Land Impact	0.000	0%	0.000	0%
15.	Land Use	-0.001	0%	-0.017	-7%
16.	Net Economic Development	0.026	9%	0.038	15%
	Total for Impact:	0.064	0.06		0.052
	TOTAL:	**0.2915**		**0.257**	

Exhibit 39: VOS for each variable included in the study for distributed and utility scale solar in USD per kWh

Direct Utility Impact (Energy/Grid)		Distributed VOS [KYD/kWh]	Utility VOS [KYD/kWh]
1.	Net avoided energy costs	0.142	0.131
2.	System Losses	0.005	0.000
3.	Net Avoided Generation Capacity	0.023	0.035
4.	Avoided Transmission Capacity	0.001	0.000
5.	Avoided Distribution Capacity	0.007	0.000
6.	Avoided Reserve Capacity	0.007	0.012
7.	Integration Costs	-0.002	-0.027
Risk Impact			
8.	Fuel Price Volatility	0.003	0.001
9.	Reliability and Resiliency	0.007	0.003
10.	Market Price Response	0.000	0.016
Environmental/Economic Impact			
11.	Net Carbon Emissions	0.023	0.022
12.	Other pollutants	0.000	0.000
13.	Net Water Use	0.006	0.004
14.	Avoided Land Impact	0.000	0.000
15.	Land Use	-0.001	-0.014
16.	Net Economic Development	0.022	0.032
	TOTAL:	**0.243**	**0.214**

Exhibit 40: VOS for each variable included in the study for distributed and utility scale solar in KYD per kWh

The section below presents an analysis of the VOS values. As seen in the Section 5, for some variables the methodology for determining the value of solar varies depending on whether the system is a distributed or utility-scale system. Therefore, the analysis is presented separately for distributed solar and utility scale solar.

8.1. Distributed VOS

The final value of distributed solar was 0.2915 USD per kWh (0.243 KYD per kWh). The final value split into the three impact categories as shown in Exhibit 41. The direct utility impact which includes grid, transmission, distribution, and generation impacts is the main contributor to the VOS, making up around 75.3% of the total value at 0.219 USD per kWh. On the other end, the risk impact category, which includes any avoided or additional risk that distributed solar brings to the utility is the smallest contributor. It makes up only 4.1% of the total value at 0.012 USD per kWh. The environmental and economic impact category captures the positive or negative environmental or economic externalities of distributed solar. It accounts for a almost 21% of the total value of solar at 0.06 USD per kWh.

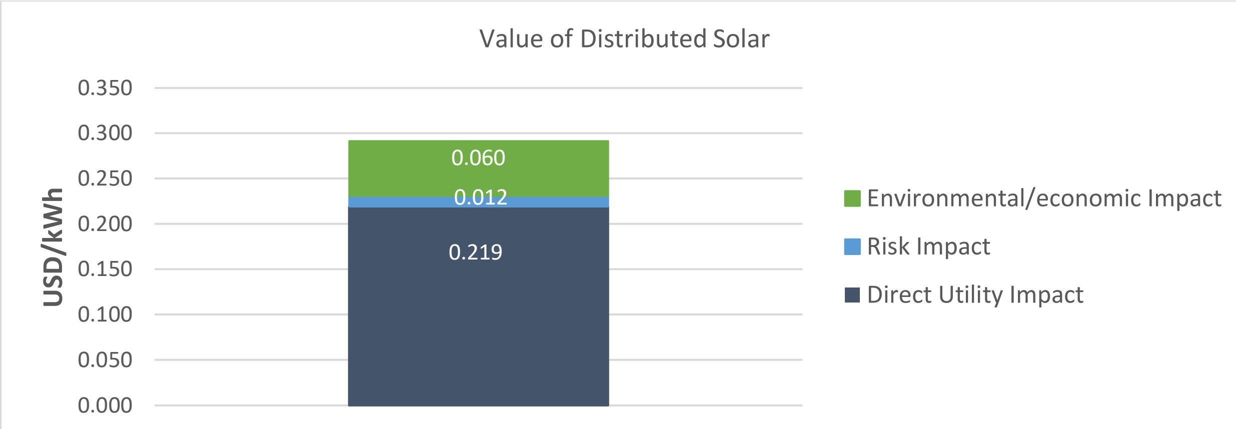

Exhibit 41: Final value of solar for distributed solar in the Cayman Islands, broken down by impact category.

Exhibit 42 shows the same impact categories but broken down per individual variable to display the contributions on a more granular level. Examining this chart reveals that the net avoided energy costs, which includes the avoided fuel costs, net avoided fixed O&M costs, and avoided variable O&M costs, is the largest overall contributor by a large margin. It makes up 0.177 USD per kWh of total VOS for distributed solar, which is roughly 61% of the total VOS and 82% of the direct utility impact.

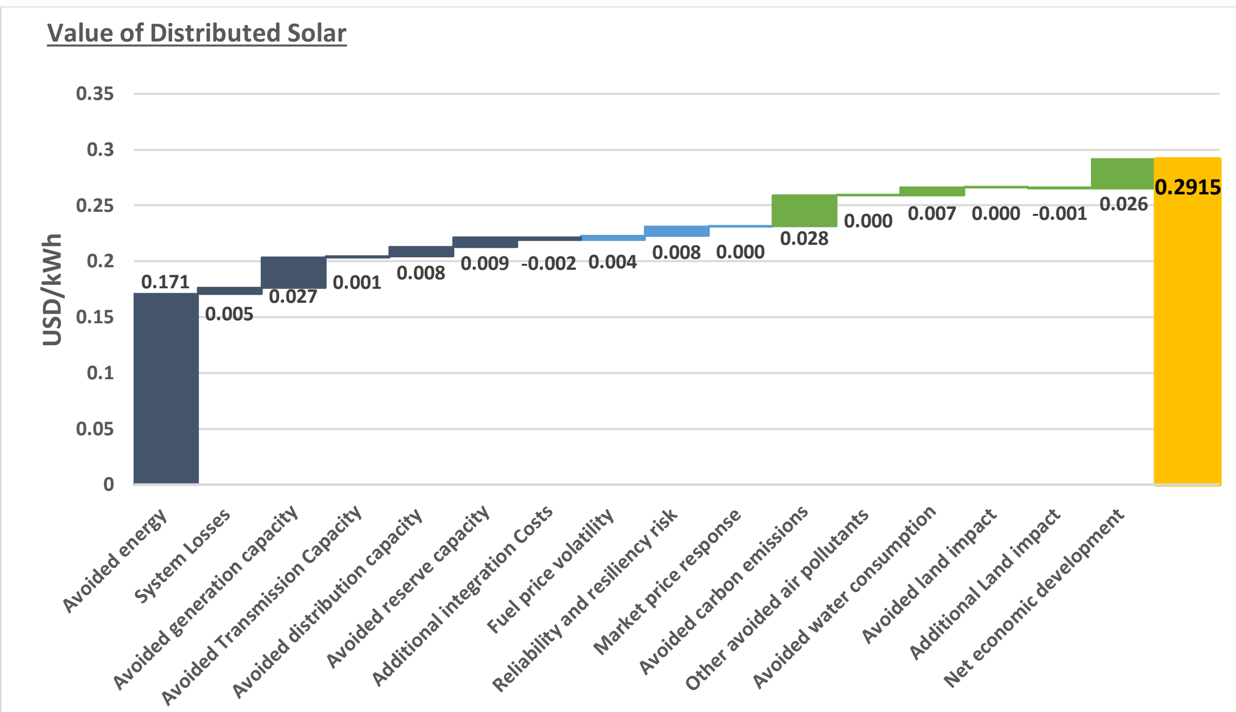

Exhibit 42: Final value of solar for distributed solar in the Cayman Islands, broken down by variable and color-coded into impact categories.

A further breakdown of the net avoided Energy Costs variable is shown in Exhibit 43. The avoided fuel costs accounts for 0.16 USD per kWh or 94% of the net avoided energy costs variable. This means that the avoided fuel cost is nearly 55% of the total value of distributed solar. The fact that avoided fuel costs is the largest value of solar in the Cayman Islands is not surprising. With diesel generators accounting for

87% of power system capacity and the relatively high average price of diesel fuel in the Caribbean, CUC inevitably has high fuel expenditures.

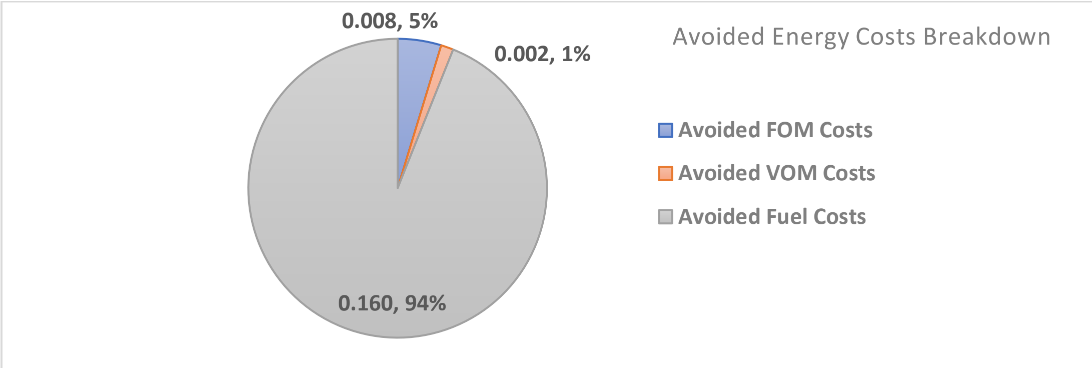

Exhibit 43: Breakdown of the Net avoided Energy costs variable for distributed solar.

Exhibit 44 replicates Exhibit 42, but with an alternative color scheme to highlight the negative values or costs of solar. Recall from Section 6 that the direct costs of installing solar systems were not included in the analysis, which would also represent an additional cost of solar. Only indirect impacts from the solar uptake are included in a value of solar study.

There are three variables which are net costs among the sixteen VOS variables explored. The first is the additional integration costs, with a value of -0.002 USD per kWh. As discussed in the methodology, this variable explored the need for BESS units in addition to feeder upgrades that would be required due to distributed solar penetration. This variable was included in the direct utility impact category. The second indirect impact of solar is the new avoided air pollutants due to the emissions of producing and commissioning the solar systems, however, it is effectively negligent. The third cost of solar is the additional land impact, included in the environmental and economic impact category. By definition, this variable will be an additional cost, however for distributed solar, the value is very low at -0.001 USD per kWh, because no addition local land is required for the resource, as it is assumed that all of the distributed solar will be located on rooftops, carports, etc.

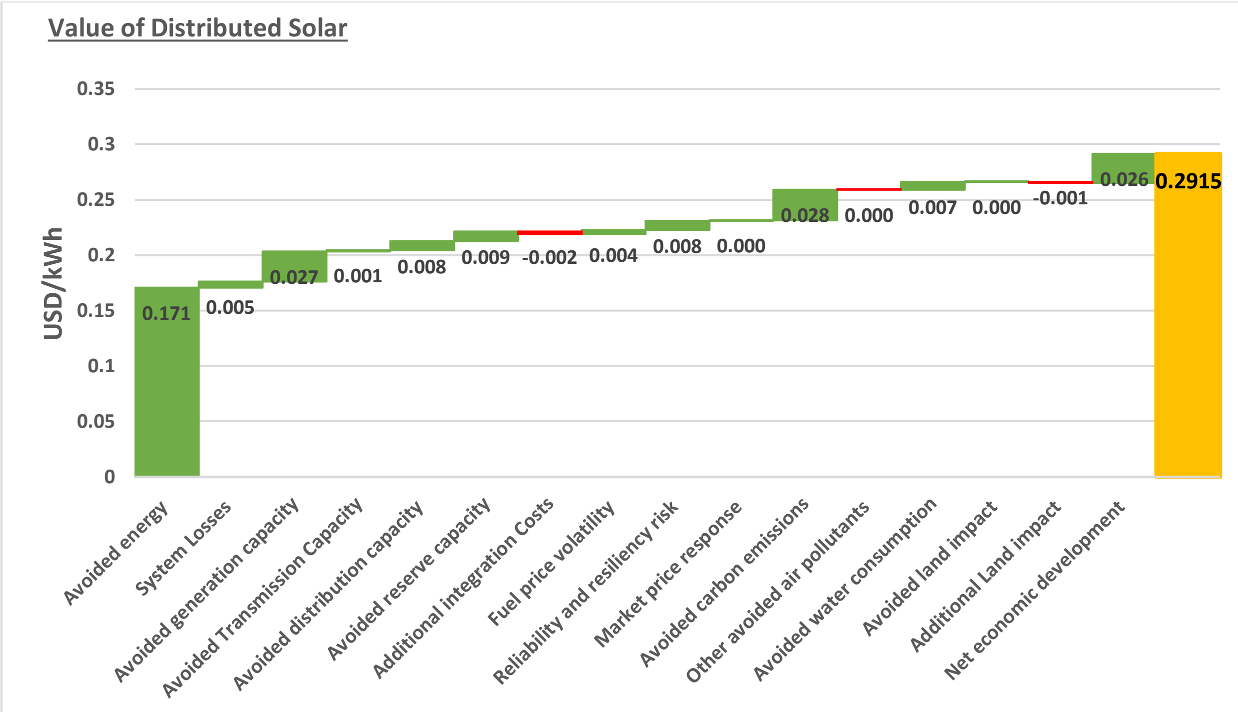

Exhibit 44: Final value of solar for distributed solar in the Cayman Islands, color-coded into values (green) and costs (red).

8.2. Utility-Scale VOS

The final value of utility scale solar was 0.257 USD per kWh (0.214 KYD per kWh). The final value was split into the three impact categories, as shown in Exhibit 45. The direct utility impact which includes grid, transmission, distribution, and generation impacts is again the main contributor to the VOS and makes up 71% of the total value at 0.182 USD per kWh. For utility scale solar, the risk impact makes up about 9% of the total value at 0.024 per kWh. The environmental and economic impact category makes up a smaller contribution to the value of utility scale solar when compared with distributed solar. For utility scale solar, this impact category accounts for nearly the same amount as the risk impact at around 20% of the total value of utility scale solar at 0.052 USD per kWh.

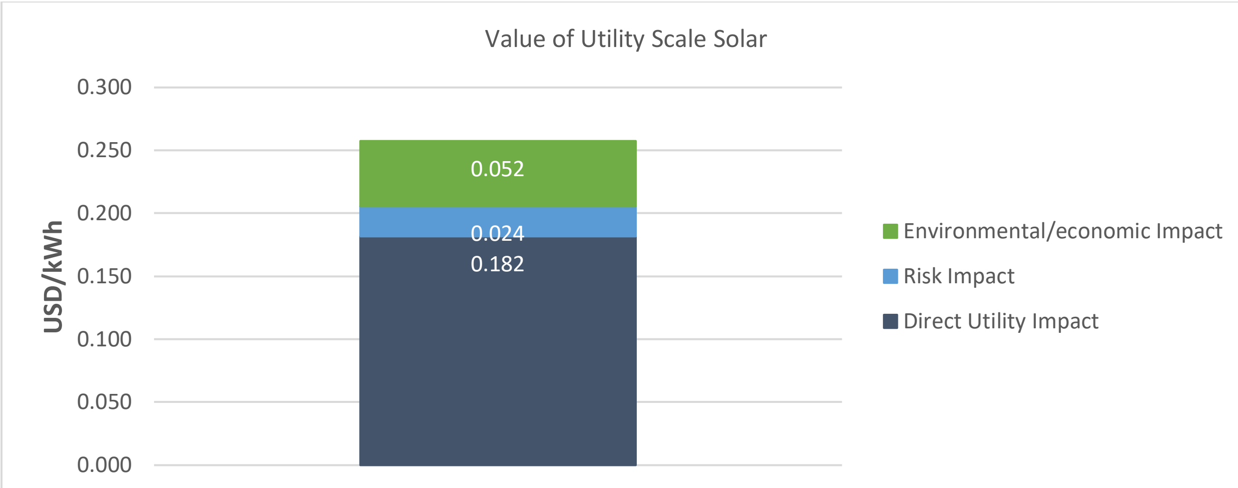

Exhibit 45: Final value of solar for utility scale solar in the Cayman Islands, broken down by impact category.

Exhibit 46 shows the same impact categories but broken down per individual variable to display the contributions on a more granular level for the utility scale solar. Like the distributed solar VOS, the net avoided energy costs variable is the largest overall contributor. It accounts for 0.164 USD per kWh of total VOS for distributed solar, which is roughly 61% of the total VOS and 86% of the direct utility impact.

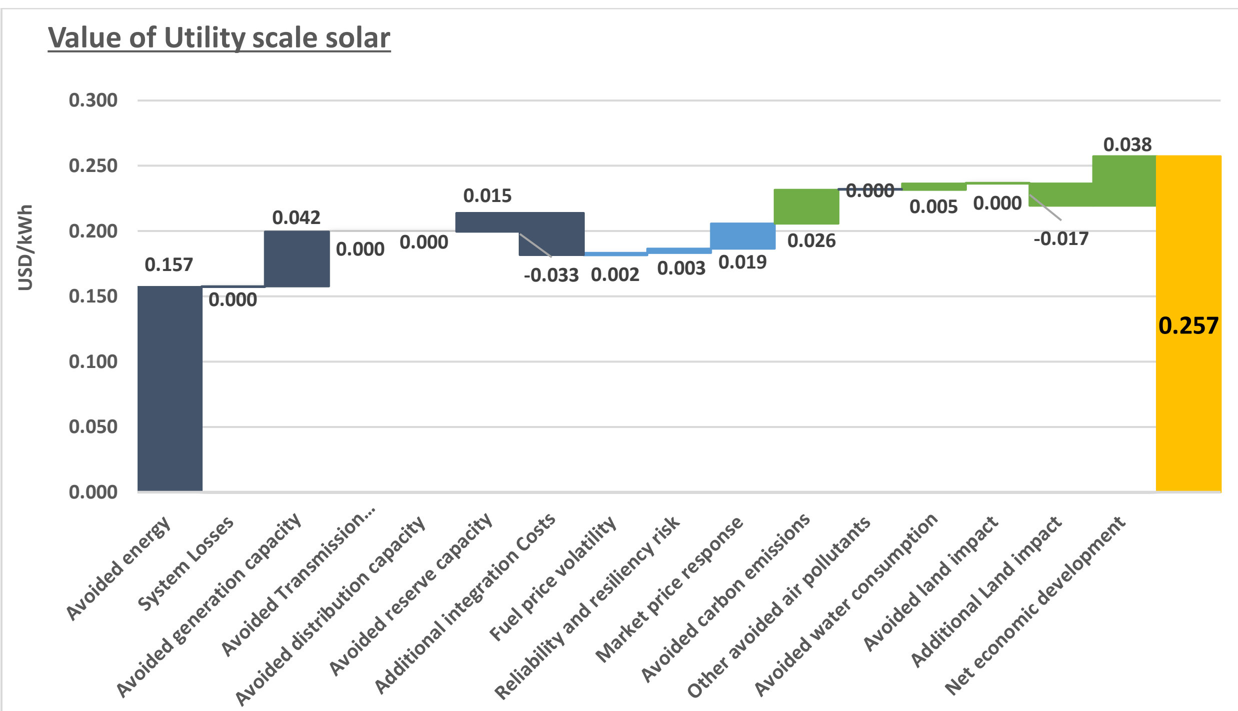

Exhibit 46: Final value of solar for utility scale solar in the Cayman Islands, broken down by variable and color-coded into impact categories.

A further breakdown of the net avoided energy costs variable in Exhibit 47 shows that the avoided fuel costs accounts for 0.147 USD per kWh or 94% of the net avoided energy costs variable. This means that the avoided fuel cost is roughly 57% of the total value of utility scale solar.

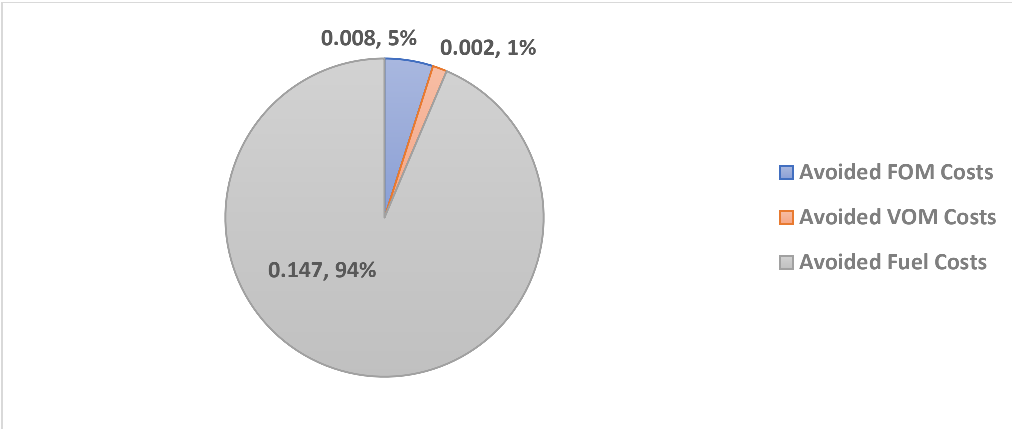

Exhibit 47: Breakdown of the Net avoided Energy costs variable for utility scale solar.

Exhibit 48 replicates Exhibit 46, but again with an alternative color scheme to highlight the negative values or costs of utility scale solar. There are only two additional costs of solar among the utility VOS variables explored. The first is the additional integration costs, with a value of -0.033 USD per kWh. This represents almost -13% of the final value of utility scale solar. As discussed in the methodology, this variable explored the need for new substations and BESS units that would be required because of utility scale solar penetration. The second cost of solar is the additional land impact, included in the environmental and economic impact category. For utility scale solar, this cost is larger than that of distributed scale because additional local land is required for utility-scale solar farms. This resulted in a larger land use cost of utility scale solar at -0.017 USD per kWh. This is about -6% of the total value of utility scale solar.

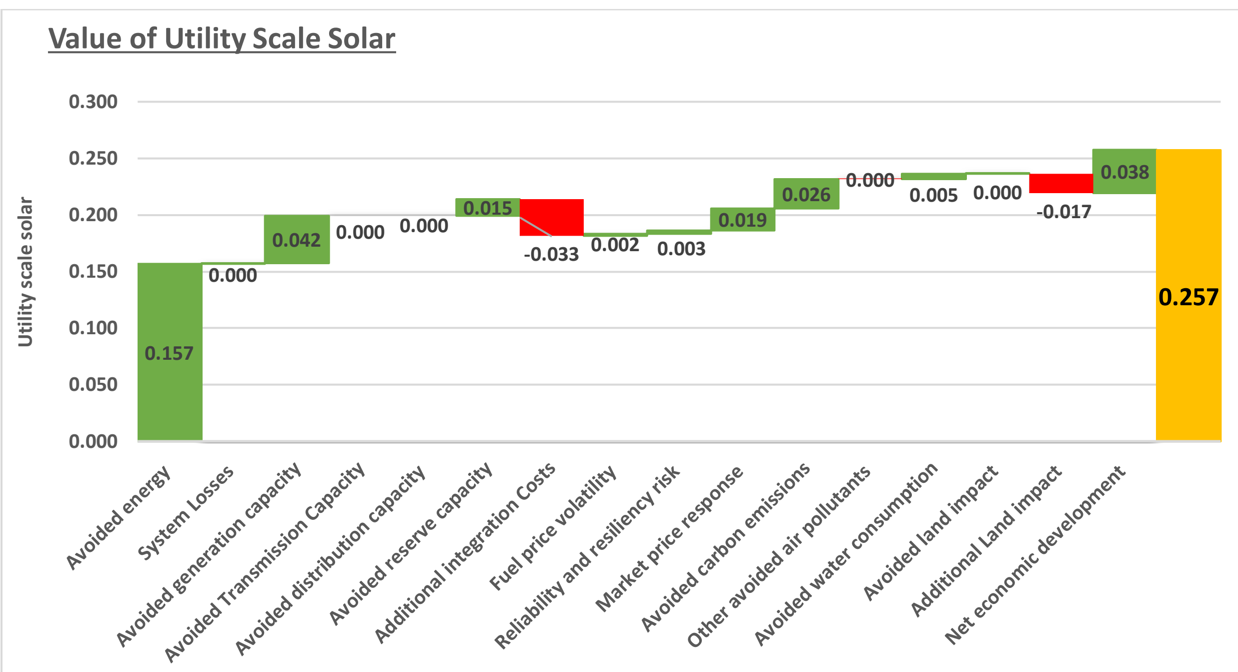

Exhibit 48: Final value of solar for utility scale solar in the Cayman Islands, color-coded into values (green) and costs (red).

8.3. Discussion

This section highlights important takeaways from the VOS study in the Cayman Islands and provides discussions around future decisions that stakeholders can consider. It is meant to provide insights regarding the development of solar in the Cayman Islands from a wide range of perspectives.

Fuel Costs

An important takeaway from the VOS study is that avoided fuel costs represent the largest contributor to the value of solar in the Cayman Islands. This directly reflects the current power system on the islands that is both dominated by and fully reliant on diesel generation, with diesel generators making up 87% of the current installed capacity on the grid. Therefore, the utility must spend a significant portion of its budget on diesel fuel to generate electricity, which represents more than 90% of electricity generation. The dependency on diesel fuel and the resulting effects are further amplified by the high fuel costs in the region. In most Caribbean jurisdictions, including the Cayman Islands, the high fuel costs are passed on to electricity consumers via fuel surcharges. Exhibit 49 shows historical CUC tariff data from January 2014 to October 2022, broken down by cost type. On average the fuel cost and fuel duty cost together represent 56% of the total electricity tariff.

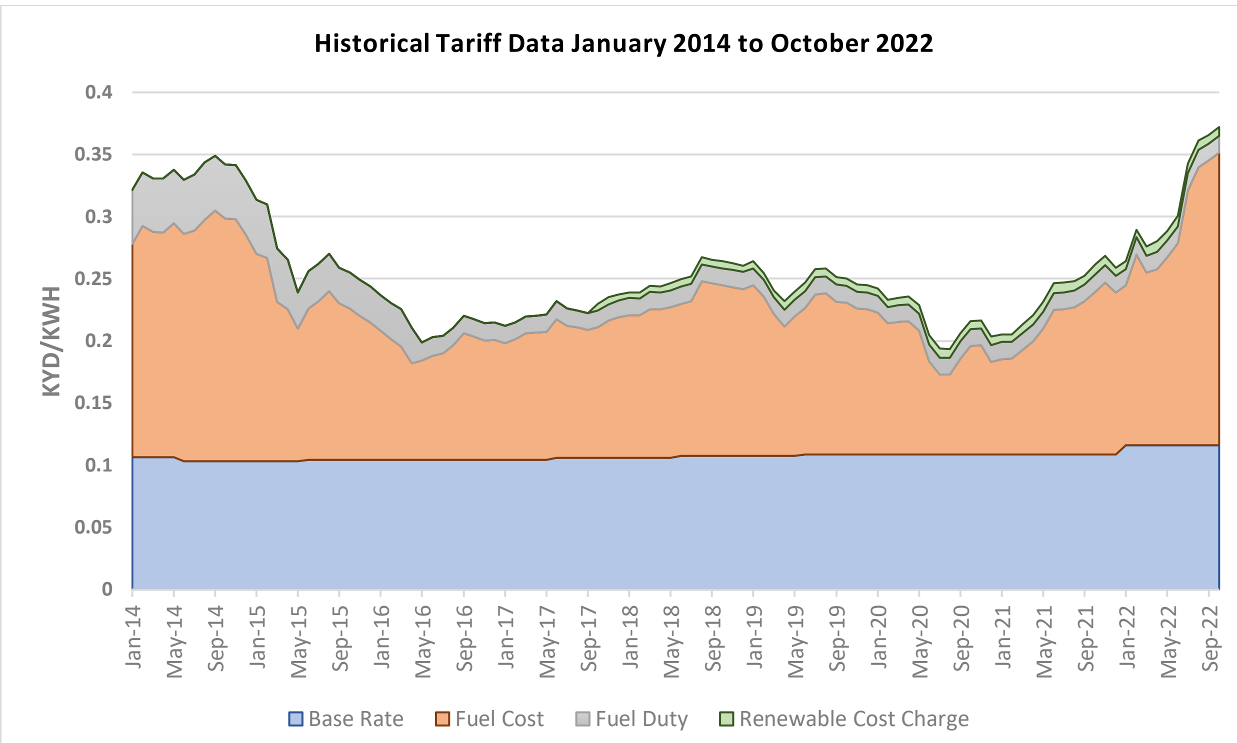

Exhibit 49: Historical CUC tariff data from January 2014 to October 2022, broken down by cost type

CUC is somewhat protected from the high fuel volatility due to hedging, however the global situation in the last year has caused a spike in fuel prices, and this is also being felt in the Cayman Islands. In fact, Exhibit 49 clearly shows the recent upward trend of fuel costs since the beginning of 2022. The uncertainty regarding future prices in the complex global context, and the fact that solar systems help reduce fuel expenditures and the fuel's inherent volatility, is the largest value that solar systems offer in the Cayman Islands.

Other Large Contributors to the VOS

Apart from fuel costs, there were four other variables that had a significant impact on the final VOS value. Avoided generation capacity, avoided carbon emissions, and net economic development also contribute towards a notable percentage of the VOS value both on the distributed and utility end. While integration costs contributed negatively to mostly to the utility VOS in a significant manner. For utility scale solar, the land use variable was a major cost of solar as well.

1. **Net avoided generation capacity:** This variable was a significant contributor to the value of solar, especially on the utility side. For the utility VOS, net avoided generation capacity made up 16.3% of the final value. Because of the larger scale of utility scale solar, new farms have the potential to offset entire fossil fuel plants from being built and commissioned, savings capital expenditure for the utility. Even distributed solar at larger penetrations can offset diesel plant generation in the long run and provide an additional value to rooftop solar. The contribution of net avoided generation capacity on the distributed end still accounted for almost 10% of the total distributed VOS.

2. **Net avoided Carbon Emissions:** Another large contributor to the VOS for both utility and distributed solar was the net avoided carbon emissions variable. U.S. EPA emission factors and shadow prices of carbon enabled the team to understand the avoided cost of pollution from diesel fuel and natural gas electricity generation, plus the additional cost of solar pollution. The deployment of solar was able to completely offset these carbon emissions, and therefore the associated costs. The contribution of this variable was 10% for both distributed and utility scale solar.

3. **Net economic Development:** The final large positive contributor to the VOS was the net economic development and impact that solar could bring to the Cayman Islands. The expansion of a solar industry in the Cayman Islands will have wide positive impacts in the local economy by providing nearly 20 direct jobs per MW of solar and another 40 indirect jobs per MW. With the units currently in place in the modified IRP, this means the creation of nearly 15,000 new jobs during the transition to solar. The contribution of this variable was 9% and 15% for distributed and utility scale solar, respectively.

4. **Integration Costs:** On the other hand, integration costs represented a large cost of solar for both utility and distributed solar. The integration costs accounted for less than -1% for distributed but almost -13% for utility. The higher penetration of solar on the grid will require necessary upgrades to the power grid to ensure seamless integration and balancing across the distribution and transmission systems. These are inevitable costs associated with solar coming online, but are small in relative comparison to the positive values of solar.

These three positively contributing variables: avoided generation capacity, avoided carbon emissions and net economic impact together account for 28% of the value of solar for distributed solar, and combined with fuel costs, the four variables make up 87% of the final distributed VOS. Similarly, net avoided generation capacity, avoided carbon emissions and net economic impact together account for 41% of the value of solar for utility-scale. Surprisingly, adding in the fuel costs, the four utility variables account for

102% of the final value of utility scale solar. This percentage is larger than 100% because the negative impact of integration costs and land use for utility scale solar, which both reduce the utility VOS significantly. Each of the other ten positively contributing variables make up less than 3% of the final VOS for distributed solar and less than 3% of the final VOS for utility scale solar except for the market price and the avoided reserve capacity.

Utility versus Distributed Solar

A relevant insight from the analysis is the discrepancy between the distributed VOS and the utility VOS. Specifically, the VOS for distributed solar is greater than the VOS for utility scale solar in the Cayman Islands. Exhibit 50 graphically displays the differences between utility and distributed results for each variable.

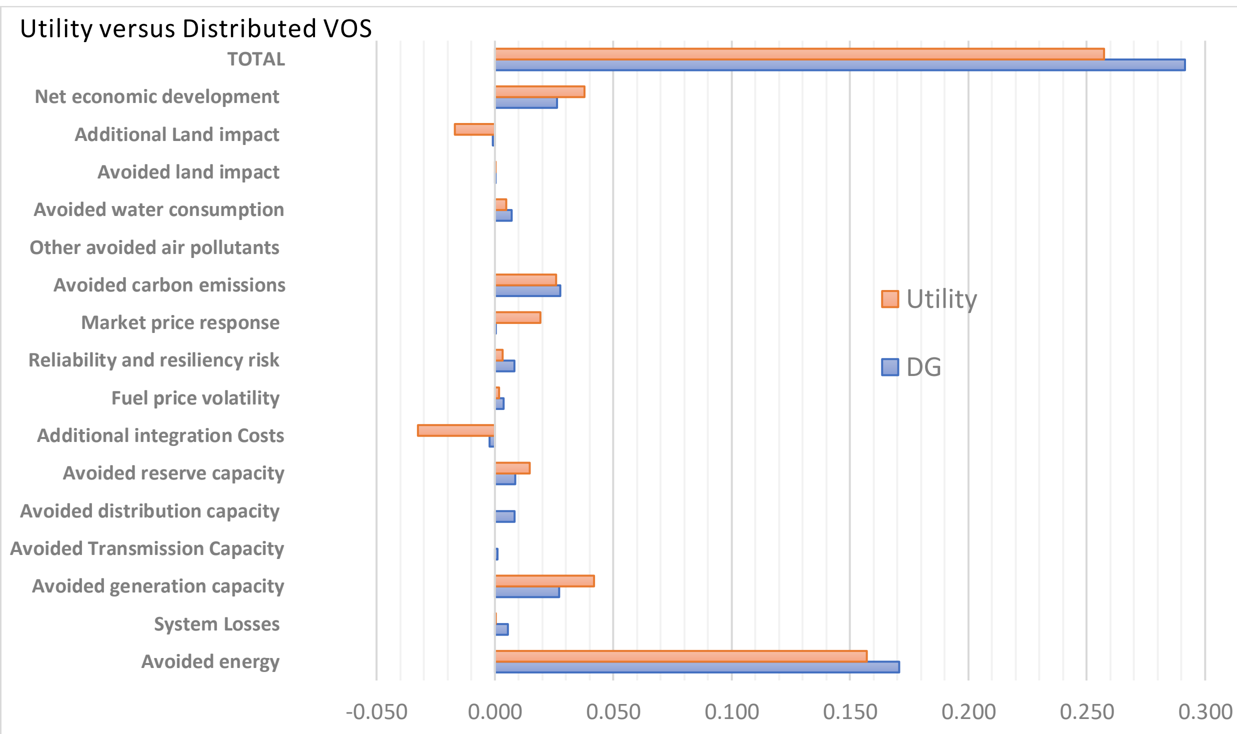

Exhibit 50: Visualization of Utility (orange) versus Distributed (blue) values of solar for the 16 variables [USD/kWh]

The VOS for utility scale solar is 0.0345 USD per kWh less than the VOS for distributed solar, which means that the utility VOS represents only 88% of the distributed VOS. This difference is largely due in part to the high cost associated with land in the Cayman Islands that would be required for a utility scale solar farm (this largely impacts the utility Land Use variable). Recall that the land use variable explores the additional land impact that solar energy has both when mining and constructing the solar PV panels and when acquiring the necessary land for the solar farm. For distributed solar, the assumption is that the systems will be rooftop mounted, and therefore require no additional land on the Cayman Islands. However, utility scale solar farms considered for the VOS analysis vary in size between 1 MW to 30 MW and require 3.5 acres of land per MW [confirmed with stakeholders]. The 140 MW of utility scale solar that is forecasted to come online in the IRP would therefore require almost 500 acres of local land, which represents more than 1% of the total acreage on Grand Cayman. In general, small island nations must heavily weigh opportunity costs and competing land use interests when considering the development of every acre of land on islands. The low supply of land and the large competition leads to very high land costs. Thus, utility scale solar results in a large cost of solar in terms of land use on the Caymans Island, which is visually confirmed in Exhibit 50.

The high land cost needed for a utility scale solar farm can be avoided with more innovative utility farms that utilize previously developed land, which would increase the value of utility scale solar. One option that has been deployed in the Caribbean for utility scale solar farms is to develop a solar car canopy or carport over a previously existing parking lot on island, as displayed in Exhibit 51. The idea behind this is that no additional land would have to be bought. Instead, the utility could lease the developed land at a much cheaper price when compared to purchasing new land. Additionally, the solar carport has other positive externalities such as providing welcomed shade for customers and community members using the space. If the Cayman Islands finds ways to incorporate utility scale solar farms into the existing urban scape, the VOS for utility scale solar would increase moderately. Thus, although the study shows that distributed solar has a higher value in the Cayman Islands, the utility value still presents many benefits and can be further increased with innovative utility scale solar farms.

Exhibit 51: Example of a solar car canopy built in a parking lot and a parking structure. Source: Friday LLC

In addition to high land costs, the higher integration costs of utility solar also differentiate it from distributed solar. Integrations costs for utility scale solar have a sizeable negative value at -0.033 USD per kWh. This makes up roughly -13% of the final utility value compared to a less than -1% contribution to the final distributed value at -0.002 USD per kWh. Thus, the system upgrade costs, particularly the additional substation costs, that 140 MW of utility scale solar would require are significant and add a larger indirect cost to utility scale solar when compared with rooftop solar systems.

Apart from high land costs and integration costs, there are several other factors that result in the utility VOS being lower than the distributed VOS. First, there are no avoided distribution costs associated with utility scale solar. As seen in Exhibit 48, there are no utility contributions coming from these variables. The avoided distribution costs only represent 2% of the distributed VOS but still adds an additional benefit to the resource. Another variable worth comparing is the market price response variable. This variable, contrary to the others examined so far, places a higher value on utility scale solar compared to distributed solar. By examining Exhibit 48 again, one can see that the market price response, or reduction in overall electricity prices in the market due to solar penetration, is negligible for distributed solar, but begins to have a relevant impact for utility-scale solar. This is in line with the theory of the merit order effect. Distributed solar, which is locally built, does not travel extensively on the T&D system, and at much lower penetration, does not have the same impact on shifting utility generation and prices away from expensive fossil fuels. However, 140 MW of utility scale solar does have the necessary penetration and impact on the T&D system to shift market prices. This logic also explains why utility scale solar has a larger value for net avoided generation capacity compared to utility scale solar.

A final observation is the small discrepancies in the avoided fuel costs and fuel price volatility between distributed and utility scale solar. For both variables the distributed solar has a higher value in USD per kWh of offset fuel and avoided fuel price volatility. The reason for this can be explained by the relative percentage in offset fuel type for an average kWh of distributed solar versus for an average kWh of utility scale solar. Exhibit 52 shows a simplified visualization of fuel offsetting. The orange block represents the kWh's generated by distributed solar and the larger yellow block represents the kWh's generated by utility scale solar, which is large because utility scale solar is likely to produce more kWh's than distributed solar for any given year except for the first few years. In the middle of the two solar generation blocks, there are the kWh's that would be generated by diesel and natural gas. The diesel generation is below the natural gas generation to represent that diesel is the first fuel that will be offset by the solar kWh's as it is the more expensive and volatile fuel. Only once all of the more expensive diesel generation has been offset, will the solar production begin to offset the cheaper NG. Thus, looking at the distributed solar, one can see that, of the total amount offset, roughly 80% of the offset generation is diesel and only 20% of the offset generation is natural gas. However, for utility scale solar, of the total offset amount, there is a lower percentage of diesel offset compared to natural gas offset. For utility scale solar, only 60% of the total offset generation is the more expensive diesel fuel and the remaining 30% is natural gas, with a lower price. This means that, even though utility scale solar offsets more fossil fuel generation, it offsets a lower relative amount of expensive diesel fuel than distributed solar does. Therefore, the avoided fuel in USD per one kWh of distributed solar is larger than the avoided fuel in USD per one kWh of utility scale solar, assuming that diesel will be offset before NG.

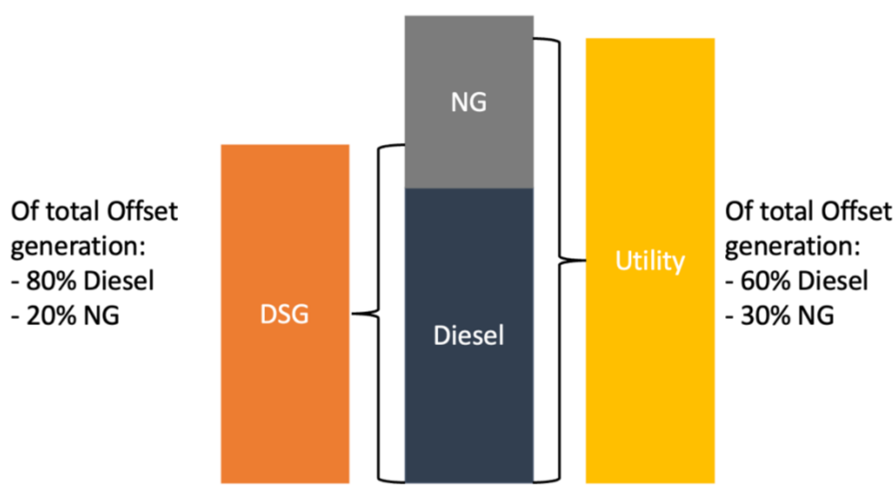

Exhibit 52: Visualization highlighting how DSG versus utility offsets fuel types

A similar line of logic means that the avoided fuel price volatility for distributed solar has a larger value than for utility scale solar, since fuel volatility arises from diesel fuel hedging. In fact, this same logic also explains why the avoided carbon emissions and avoided water consumption are larger for distributed solar compared to utility scale solar. One kWh of distributed solar offsets relatively more diesel fuel than a kWh of utility scale solar, and diesel has a higher carbon emissions factor. Similarly, one kWh of distributed solar offsets relatively more diesel fuel than a kWh of utility scale solar, and diesel has a higher water consumption compared to natural gas. An important caveat is that the reason this phenomenon arises is that distributed solar is capped at 70 MW in line with the preferred expansion plan in the 2017

IRP. As distributed generation is allowed more capacity and has a higher penetration level, the avoided fuel costs, avoided fuel volatility, and avoided carbon emissions should converge for utility and distributed solar.

Stakeholder Alignment

Stakeholders' assessment of the relative value of the VOS variables aligned broadly with the calculated VOS values. Exhibit 53 displays the weighted average values for each VOS variable from the stakeholder surveys. As measured in the surveys, stakeholders assigned the greatest value to avoided carbon emissions and avoided energy, with weighted average scores of 8.64 and 8.62 out of 10. These two variables were also among the biggest contributors to the distributed and utility VOS values. At the same time, stakeholders considered avoided other pollutants to have significant impact on the value of solar, however the opposite was the case due to the relatively low equivalent carbon dioxide equivalent emissions factors for the expected future energy mix in the Cayman Islands.

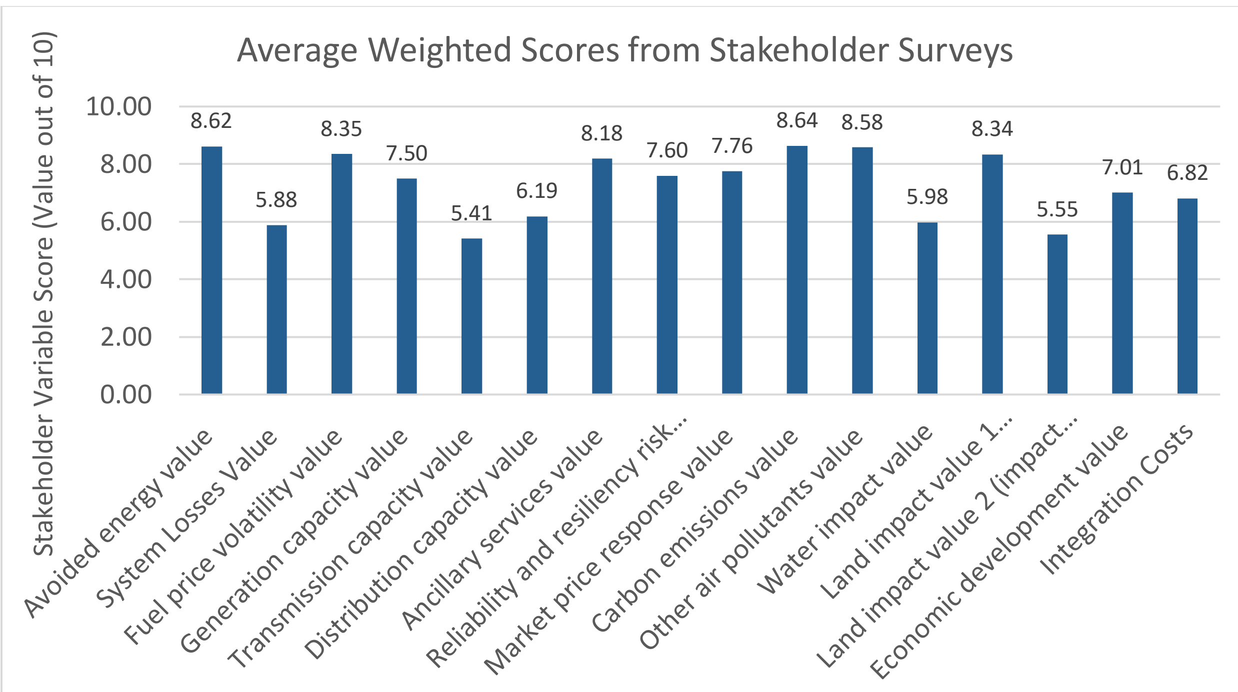

Exhibit 53: Stakeholder weighted average scores for the VOS

8.4. Renewable Energy Scenario

The VOS analysis was built upon a slightly modified preferred expansion plan that was taken directly from the 2017 IRP. Recall from Exhibit 11 (displayed again below) that this scenario sees a large push for natural gas and utility scale solar build-out, which reached 2052 capacities of 173 MW and 140 MW respectively. Additionally, this expansion plan capped distributed solar at 70 MW.

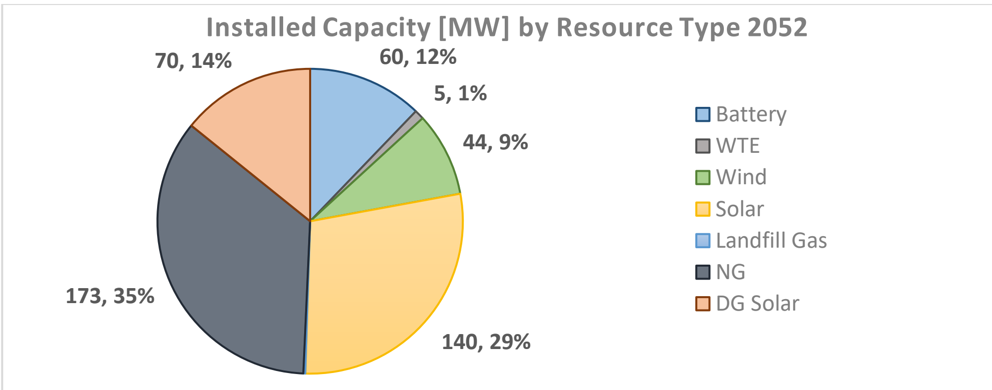

Exhibit 11 Repeated: Installed Capacity by Resource Type in 2052 according to 2017 IRP

Renewable Energy Scenario Design

In addition to this base scenario, the RMI team also created a renewable energy scenario that was more in line with the long-term goals outlined in the 2017-2037 National Energy Policy (NEP). Specifically, the renewable energy scenario was designed to reach the following specific objectives:

- 25% renewable energy electricity generation by 2025
- 70% renewable energy electricity generation by 2037 [27]
- 90+% renewable energy electricity generation by 2050[28]

In order to reach these objectives, a new expansion plan was created, and it is displayed in Exhibit 54. The updated expansion plan sees a larger push for wind and solar to replace natural gas generation to meet the stated renewable electricity generation goals. Specifically, the plan includes the addition of 310 MW of utility scale solar to the grid, on top of the 5 MW Bodden Town solar farm, and a build out of 120 MW of wind capacity. Distributed solar is no longer capped at 70 MW and reaches a new capacity of 120 MW. Battery storage capacity also increases to help with the grid integration of large amounts of intermittent energy sources. Additionally, 100 MW of NG is still brought online for base generation, reserve capacity and nighttime supply of energy and to ensure that there is no unserved energy during the 30-year horizon.

[27] http://www.dlp.gov.ky/portal/pls/portal/docs/1/12374582.PDF , Goal 3 of the NEP

[28] Goal of power sector following 2017-2037 NEP according to National Energy Policy Unit https://www.energy.gov.ky/energy-security

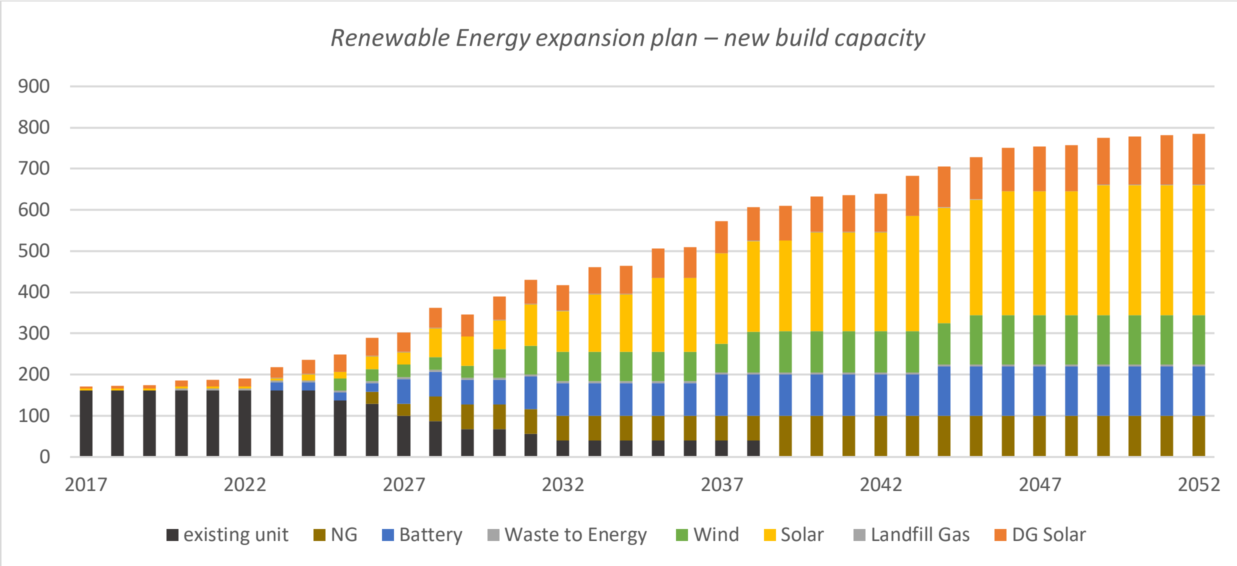

Exhibit 54: Renewable Energy expansion plan – new build capacity per technology type.

Future production from the various technology types were based on Table 1 of the NEP, which shows 2037 production percentages, and then forecasted out to 2052. Exhibit 55 shows the 2052 installed Capacity in MW for the renewable energy scenario by technology type.

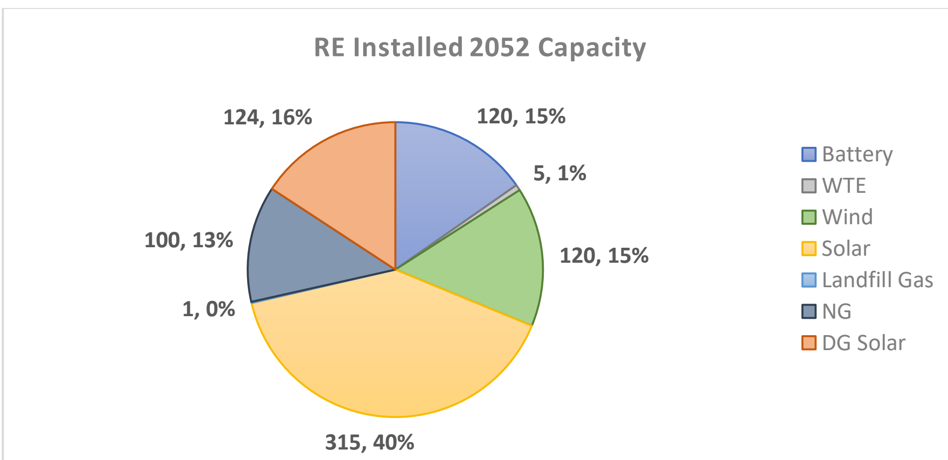

Exhibit 55: Installed Capacity by Resource Type in 2052 according to new renewable energy scenario

The team used this new expansion plan as the guideline to expand the simulated distributed and solar fleets. Hourly generation values were multiplied by a scaling factor each year to obtain new solar project values. A final check was to account for degradation throughout the 30-year time period. Other than solar capacity, all other values remained the same when creating the new solar fleets. For utility scale solar, the new build capacities were as follows:

Year	New-Build Utility Scale Solar Capacity [MW]
2024	10
2026	15
2028	40

2031	30
2033	40
2035	40
2037	40
2040	20
2043	40
2046	20
2049	15

Exhibit 56: New-build utility scale solar for the Cayman Islands. Source: 2017 IRP

All other inputs and assumptions were kept constant for the renewable energy scenario analysis.

Results

The numerical results obtained in the renewable energy scenario VOS study are presented for each variable for both distributed solar and utility scale solar with the percentage contribution to the total VOS in Exhibit 57. The table enables one to clearly compare utility and distributed solar against one another and view the relative contributions of each variable in numerical form.

Direct Utility Impact (Energy/Grid)		Distributed VOS [USD/kWh]	Percentage of Total VOS	Utility VOS [USD/kWh]	Percentage of Total VOS
1.	Net avoided Energy Costs	0.160	55%	0.147	56%
2.	System Losses	0.002	1%	0.000	0%
3.	Net Avoided Generation Capacity	0.041	14%	0.065	25%
4.	Avoided Transmission Capacity	0.001	0%	0.000	0%
5.	Avoided Distribution Capacity	0.006	2%	0.000	0%
6.	Avoided Reserve Capacity	0.012	4%	0.018	7%
7.	Integration Costs	-0.007	-2%	-0.033	-13%
	Total for Impact:	0.215			0.196
Risk Impact					
8.	Fuel Price Volatility	0.002	1%	0.001	0%
9.	Reliability and Resiliency	0.005	2%	0.002	1%
10.	Market Price Response	0.000	0%	0.034	13%
	Total for Impact:	0.008			0.037
Environmental/Economic Impact					
11.	Net Carbon Emissions	0.027	9%	0.027	10%
12.	Other pollutants	0.000	0%	0.000	0%
13.	Net Water Use	0.005	2%	0.003	1%
14.	Avoided Land Impact	0.000	0%	0.000	0%
15.	Land Use	-0.001	0%	-0.049	-19%
16.	Net Economic Development	0.033	12%	0.048	18%
	Total for Impact:	0.065			0.029
	TOTAL:	0.2879		0.262	

Exhibit 57: VOS Results for the renewable energy scenario

A quick assessment reveals that the utility VOS has increased by 0.5 cents USD per kWh in the renewable energy scenario. The distributed VOS has decreased by 3.6 cents USD per kWh. Exhibit 58 allows one to directly visualize how the utility and distributed values compare in the renewable energy scenario.

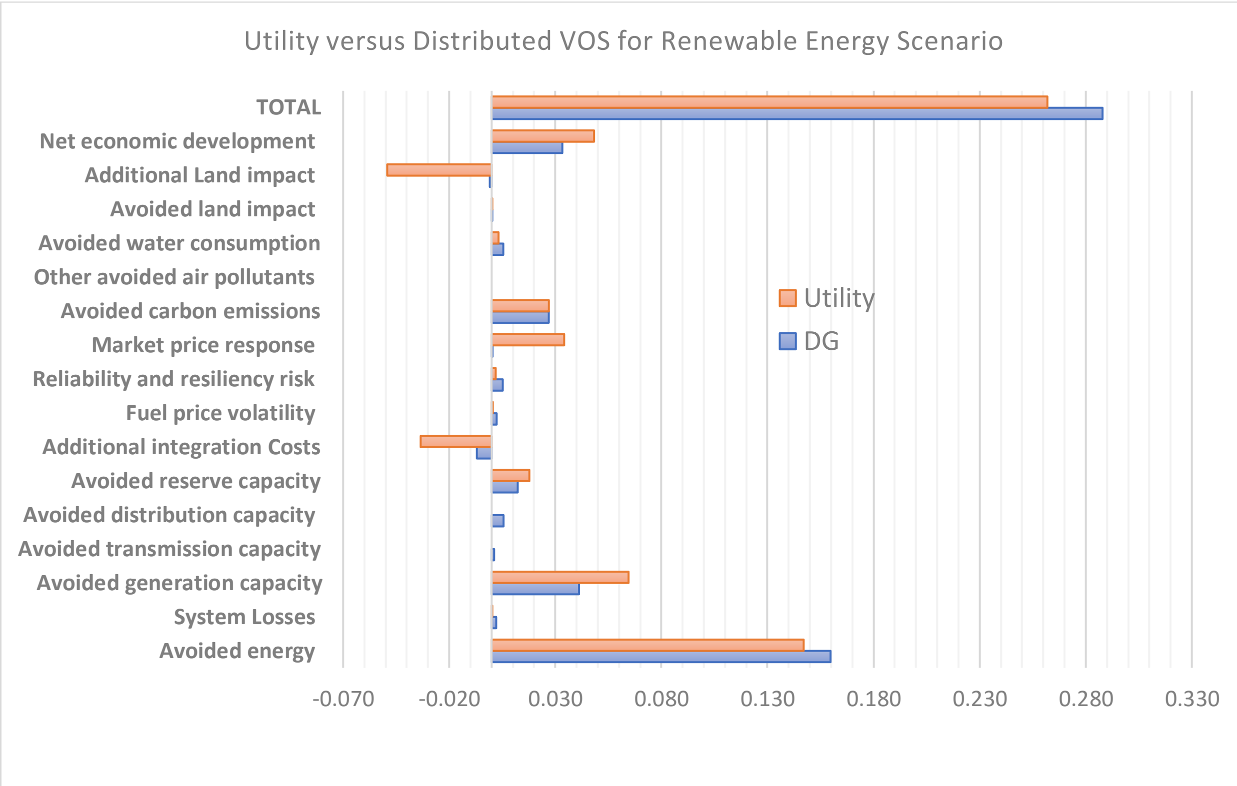

Exhibit 58: Utility (orange) versus Distributed (blue) values of solar [USD/kWh] for the renewable energy scenario.

There are several large takeaways from Exhibit 58 and the renewable energy scenario. First, as was expected, the distributed and utility values start to converge across variables, which explains why the total VOS values are beginning to coincide. For example, the avoided carbon emissions and fuel price volatility have increased for the utility scale and now the values are relatively equal between utility and distributed systems. With distributed solar no longer being capped at 70 MW, the relative offset of fuel type for a kWh of distributed solar becomes more in line with that of utility scale solar. Another noticeable impact of the renewable energy scenario is that integration costs are also converging. In the base case, utility integration costs were 0.031 USD/kWh costlier than distribution integration costs, however, in the renewable energy scenario, utility integration costs are only 0.026 USD/kWh costlier than distribution integration costs. In the renewable energy case, utility integration costs have decreased since substation upgrades can impact larger amounts of utility MW's and distribution integration costs have increased since more BESS is needed in the system to enable the integration. Another takeaway is that the land use variable's negative impact on utility scale solar is even larger in the base scenario because the land costs are linearly expanding and more solar is developed in later, more expensive years, and for every 100 acres bought, there is an additional 2.25% spike. Again, with innovative solutions to reduce the land use variable, the values of solar between distributed and utility scale solar would coincide.

The team analyzed not only the differences between utility scale solar and distributed solar in the renewable energy case but also how the values changed for each variable from the base scenario to the renewable energy scenario. Thus, Exhibit 59 shows all four values – distributed solar in the base case (light blue), distributed solar in the renewable energy case (dark blue), utility scale solar in the base case (light orange), and utility scale solar in the renewable energy case (dark orange). It is easy to see the overall shifts that take place when moving from the base scenario to a higher solar and renewable energy penetration scenario.

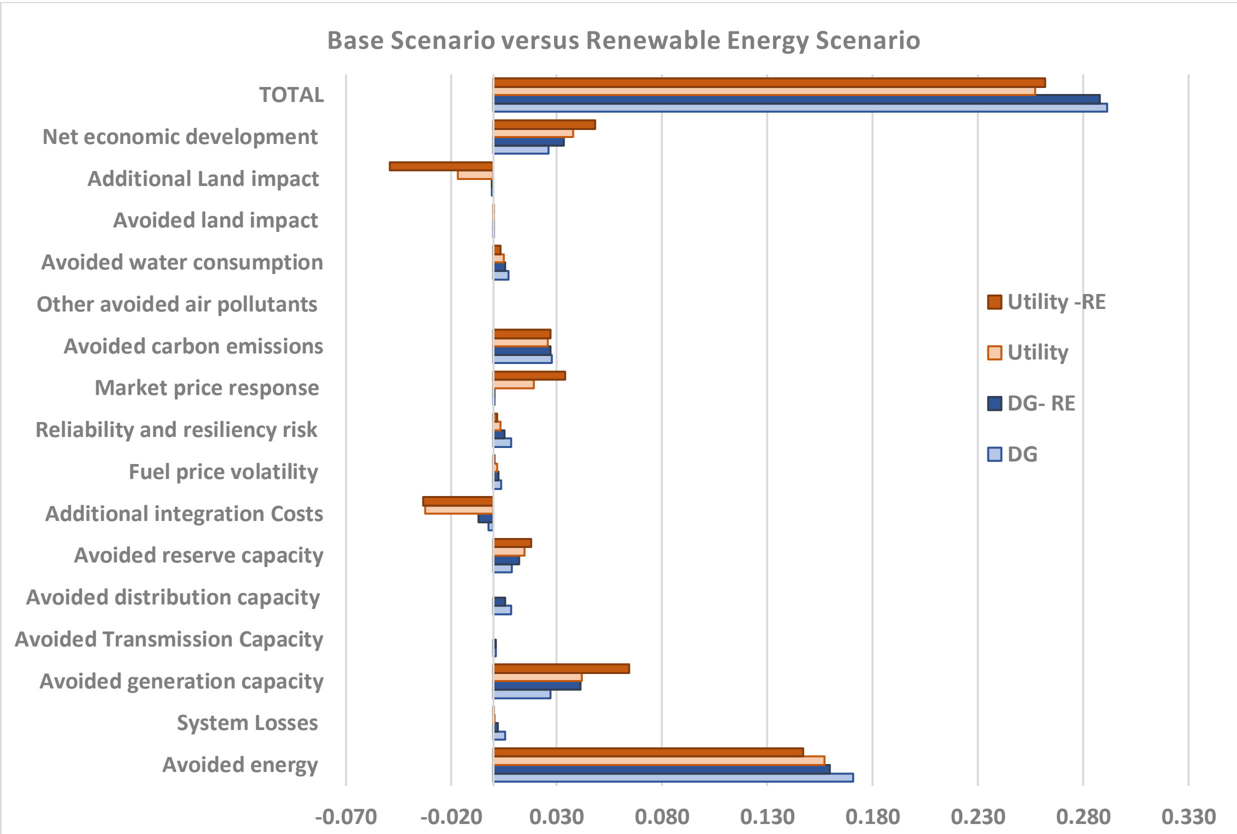

Exhibit 59: Base case values (lighter shades) versus renewable energy values (Darker shades) in USD/kWh for distributed (blue) and utility (orange) solar.

This graph provides several insights. In general, variables that gave additional value to the VOS in the base case increased slightly in the RE scenario such as avoided generation capacity, avoided reserve capacity, market price response, and net economic value. The reason for many of these slight increases is that as solar is added in higher penetrations to the system there is no diminished return on new build out, which means that net economic value and avoided capacity will trend upwards. Market price has increased because there is even more cheap energy on the grid which replaces expensive, fossil fuel technologies. Some of the variables remained quite constant when moving towards a higher penetration of solar including, carbon emissions, avoided transmission and distribution capacity (for distributed solar only) and fuel price volatility. Specifically for fuel price volatility, the value should not change much since there is no hedging for natural gas and so the capacity of natural gas would not impact the variable that significantly.

Finally, some variables decreased, including avoided water consumption, system losses and net avoided energy costs. This can be explained by the logic presented back in Exhibit 52, where it was shown that even though more solar capacity means that solar generation offsets more fossil fuel generation overall, it also offsets a lower relative amount of expensive diesel fuel to natural gas than a low solar capacity generation would. Thus, as the solar capacity and solar generation increase for both distributed and utility scale solar, the avoided fuel costs value, in terms of USD per kWh, decreases. The same logic also explains why the avoided water consumption value and system losses decrease in the renewable energy scenario. Essentially, there is a diminished return on avoided fuel, avoided system losses and avoided water as more solar is added to the system.

Regarding the variables that gave additional cost to the VOS, integration costs have shifted in different directions for utility and distributed solar. As mentioned before, utility integration costs have decreased since substation upgrades can impact larger amounts of utility MW's and distribution integration costs have increased since more BESS is needed in the system to enable the integration. The land use cost for utility increased quite significantly since more land is acquired for the large solar capacity and this caused prices to rise even more due to the price spiking effect of 2.25% increase every 100 acres of land purchased. In the renewable energy case, more than 1,100 acres of land are required for utility scale solar, which is nearly 2.3% of the total land on Grand Cayman.

9. Conclusion

The Value of Solar (VOS) study explored the net benefits of solar energy provided to the grid from both distributed and utility scale solar in the Cayman Islands. The analysis explored sixteen variables that contributed to the VOS value, segmented into three impact categories: direct utility impact, risk impact, and environmental/economic impact.

The overall VOS value for distributed solar generation (DSG) in the Cayman Islands was calculated at USD 0.291/kWh. While the VOS value for utility-scale solar was USD 0.257/kWh. For both VOS values, the direct utility impact, which includes net avoided energy costs, and grid, transmission, distribution, and generation impacts, accounted for the majority of the VOS value: 75.2% of the distributed VOS and 70.5% of the utility VOS. Risk impact accounts for 4.2% of the distributed VOS and 9.4% of the utility VOS. While the environmental/economic impact makes up 20.6% and 20% of the distributed and utility VOS values respectively.

Stakeholder insights also provided valuable perspective on the value of solar in the Cayman Islands. Their perspectives broadly covered environmental, energy, and economic impacts from the uptake of solar in the Cayman Islands, and through surveys, they identified perceived positive and negative outcomes of solar on the island and assigned scores to each variable in the VOS analysis.

The Value of Solar (VOS) Study is a critical step towards helping the Cayman Islands attain its goals outlined in the National Energy Policy, while capturing the true value and costs for solar PV and the impact on the utility, economy and broader society. Through the analysis of the core contributors to the overall solar PV value, the Cayman Islands possesses an important asset to drive renewable energy uptake, while aiming to deliver a lower cost, reliable electricity system that benefits all Cayman citizens.

10. Appendix

10.1. Tariff Review

Current Tariff Methodology, Observations and Considerations

CUC is regulated by the Cayman Islands Utility Regulation and Competition Office ("OfReg") which sets their base rates charged to ratepayers. The CUC base rates are designed to recover all non-fuel and non-regulatory costs and include *per kilowatt-hour* ("kWh") electricity charges and fixed facility charges. Factors used to adjust the rate include setting a Return on Rate Base (RORB) and the increase in the applicable United States (US) and Cayman Islands consumer price indices (CPI). Base rates are subject to an annual review and adjustment each year through the Rate Cap and Adjustment Mechanism. Fuel costs, renewables costs and regulatory fees are billed as separate line items as a per kWh charge without mark-up, while all fuel, lubricating oil and renewables costs are passed through to customers without mark-up as a per kWh charge. The Company's capital expenditure plan also requires regulatory approval.[29]

Given that a large portion of CUC's cost recovery is dependent on a Return on Rate Base, as distributed generation resources grow on the system, the current tariff structure will be ill-suited to compensate for the structural changes brought by a modern utility operating environment. Some of the key components to a modernized tariff include charges for: energy (kWh), power (kW), purchased power recovery, time of use, fee-for-services, alternative revenues, fuel recovery, service availability charges, asset recovery (including generation, transmission, distribution and delivery charges), reserve replenishment, energy efficiency incentives, public benefits surcharges, operations and maintenance recovery, taxes, and a reasonable rate of return. Although not all categories or charge types need to be included in a given tariff structure, having more granularities allows for increased versatility in tariff setting. Although there are a range of structures and mechanisms available to guide tariff setting, RMI recommends that a comprehensive tariff modernization exercise be conducted in the near future, taking into consideration asset, operational and service-based tariffs.

RMI has reviewed and compared the Cayman tariff to multiple regional tariffs in the Tariff Analysis section below.

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[29] CUC. 2021. "2021 Annual Report".
https://www.cuc-cayman.com/reports/download_pdf?file=1644947773cuc_ar_2021_final_110222.pdf

Tariff Analysis

The table below highlights the tariff breakdown from a number of jurisdictions (Barbados, Bermuda, Jamaica, and Kauai Island – Hawaii) to compare with the tariff structure in the Cayman Islands. These jurisdictions were selected due to the relevance of their geographical context, with 3 being islands located in the Caribbean, and the fourth being part of a US island state situated in the Pacific and known for its ambitious renewable energy goal of 100% by 2045.[30]

Component Type	Cayman Islands	Barbados	Bermuda	Jamaica	Kauai (Hawaii)
Base energy charge	√	√	√	√	√
Facilities/Customer charge	√	√	√	√	√
Demand charge	√ (some customers)	√ (some customers)	√ (some customers	√ (some customers)	√ (some customers
Additional Capacity Charge	√				
Fuel cost	√	√	√	√	√
Fuel duty	√	*	*	*	*
Renewable energy- related charge	√			√	√
Regulatory fee	√		√		
Feed-in tariff	√ (some customers)	√ (some customers)	√ (some customers)	√ (some customers)	√ (some customers)

Exhibit 60: Comparison of tariff components with regional and international island jurisdictions

** Included in fuel cost.*

The tariff structure of all of the jurisdictions compared includes a base energy charge, some type of facilities charge, a demand charge, a fuel cost charge, and a feed-in tariff. The base energy charge generally covers the non-fuel costs of electricity production and delivery to customers, such as operation and maintenance costs of generation, transmission and distribution equipment. The facilities charge, as the name suggests, covers the costs associated with the maintaining customers' electricity service. This is sometimes called a Customer Charge and covers the costs of installing and maintaining meters, reading meters and bill processing. Demand charges for all jurisdictions were only applied to some customer classes, usually those with a high electricity demand. In the Cayman Islands, participants in the DER programme are also required to pay demand charges. An Additional Capacity charge also exists, which differs from the Monthly Demand Charge in that it is based on a customer's long-term demand rather than short-term demand. This type of differentiation in demand charges was not observed in the other jurisdictions investigated.

[30] Hawaii State Energy Office. 2022. "Hawaii Clean Energy Initiative". https://energy.hawaii.gov/hawaii-clean-energy-initiative/#:~:text=The%20goal%20of%20the%20Hawai,percent%20clean%20energy%20by%202045

Fuel cost charges are intended to cover the cost of fuel used in the generation of electricity and are often passthrough charges to customers. It is often called a fuel surcharge or fuel clause adjustment, and this is common in many tariff structures. This charge was observed in the structures of all jurisdictions explored in this analysis. The final component, which was common to all jurisdictions, the Feed-in Tariff, refers to the rate that is paid to prosumers who sell electricity to the grid under various mechanisms developed by utilities and regulators.

Renewable energy charges were only seen explicitly in the structures for the Cayman Islands and Kauai, however they differed in terms of the types of costs that were covered. In Cayman, the renewable energy charge covers the cost of purchasing renewable energy from prosumers and IPPs. In Kauai, there are two renewable energy-related charges, the Renewable Infrastructure Program charge and the Green Infrastructure fee. The first covers the costs of projects that facilitate the development or integration of renewable projects, while the second supports a state program aimed at creating low-cost financing opportunities for those who are not able to afford or qualify for financing for renewable or energy efficiency projects. Neither of the charges cover the cost of purchasing renewable energy. The tariff structure in Jamaica does, however, feature an IPP charge which covers the cost that the utility pays IPPs for electricity. These IPPs include renewable energy power producers.

Both Cayman Islands and Bermuda feature regulatory fees in their rate structure, although for the Cayman Islands, the fee is only applicable to customers whose consumption is greater than 1000 kWh for a particular billing period. In both jurisdictions, this fee represents a passthrough to the customer. Finally, the Cayman Islands was the only jurisdiction in which a charge to cover taxes on fuel was explicitly seen via its Fuel Duty charge. Many other jurisdictions choose to include these taxes within the fuel cost charge. Barbados also has value-added tax (VAT) added to customers' subtotal.

In general, many of the components of the Cayman Island's rate structure were reflected in structures of other jurisdictions regionally and internationally. The regulatory fee is uncommon among the jurisdictions explored, only seen in Bermuda. A charge to cover the costs of purchasing renewable energy from prosumers and IPPs was not observed explicitly in the other structures, although Jamaica's structure featured an IPP charge which would cover those costs.

Jurisdiction	Methodology	Category	Credit Rate (USD/kWh)	Review Period
Cayman Islands	Cost of renewable energy	0-5 kW 5 kW – 10 kW 0 kW – 5 kW (NHDT) 0 kW – 100kW	0.210 0.180 0.336 0.252	n/a
Barbados*	Combination of Return on Investment and LCOE	Solar, up to 10 kW Solar, Above 10 kW to 100 kW Solar, Above 100 kW to 250 kW	0.209 0.219 0.205	20-year contract for asset
Bermuda	Avoided cost of generation	-	0.2265	3 years
Jamaica	Short-run marginal cost of avoided generation plus 15% premium	0-100 kW	0.1879	1 month
Kauai (Hawaii)	Avoided energy costs	0-100 kW	0.1538	Base figure is revised annually but adjusted monthly

*Barbados has numerous FiT categories varied by both technology and size. The ones shown here were selected due to their relevance to the topic of the VOS analysis and hence comparability with Cayman.

Exhibit 61: Comparison of FiT details among regional and international jurisdictions.

As seen from the table above, methodologies for determining a FiT include use of the levelized cost of energy (LCOE), use of the avoided generation cost or use of other avoided costs. As highlighted in the Barbados and Jamaica examples respectively, layers can be added to include a return on investment or percentage premium as part of the FiT determination. Each type of methodology has its merits as well as its disadvantages, and suitability of a methodology to a particular jurisdiction depends on factors such as its energy goals and readiness of the grid infrastructure for increasing penetrations of renewables. Methodologies may also vary in suitability as renewables become more widespread. For example, if a FiT is based on the avoided cost of fuel, then as the renewable energy penetration increases, and subsequently the fuel required to meet demand decreases, the value of the FiT would decrease as well since a lower fuel cost is being avoided. This can be disincentivizing to further uptake of renewables as potential prosumers may no longer see it as a worthwhile investment.

Analysis of CUC’s current tariff structure showed that the components present in the rate structure are on par with the other jurisdictions. However, the utility’s cost recovery mechanism should be updated to better suit the needs of a modern utility environment where renewables are prevalent. There is no perfect, one-size fits all solution. However, increased flexibility and new innovations in how renewable energy tariffs are governed and structured will be an important next step to help encourage wider deployment of renewable energy across the Cayman Islands.