Integrated Resource & Resiliency Plan for Barbados

Activity B: Final Report

20 August 2021

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Inter-American
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Acronyms and Abbreviations

Abbreviation	Description
A	Ampere
AC	Alternating Current
ac	Acres
AGC	Automatic Generator Control
ARIMA	Autoregressive Integrated Moving Average
BAMCL	Barbados Agricultural Management Corporation Limited
BESS	Battery Energy Storage System
bl	Barrel
BLPC	Barbados Light and Power Company
BNEP	Barbados National Energy Policy
BNEP 2019-2030	Barbados National Energy Policy 2019-2030
BNOCL	Barbados National Oil Company Ltd
BNSI	Barbados National Standards Institute
BREA	Barbados Renewable Energy Agency
BWA	Barbados Water Authority
CAES	Compressed Air Energy Storage
CARICOM	Caribbean Community
CL	Cruise Liner
CSP	Concentrated Solar Power
CO2	Carbon Dioxide
DC	Direct Current
DSM	Demand Side Management
DSR	Demand Side Response
ECREU	Energy Conservation and Renewable Energy Unit
EE	Energy efficiency
EIA	Environmental Impact Assessment
EIA	(United States) Energy Information Administration
ELPA	Electric Light and Power Act 2013
ELPAC	Electric Light and Power Act Committee
EMS	Energy Management System
EPD	Environmental Protection Department
ESIA	Environmental and Social Impact Assessment
EV	Electric vehicles
FCA	Fuel Cost Adjustment
FiT	Feed in Tariff
FRES	Forced Firm Renewable Scenario
FSRU	Floating Storage Regasification Unit
FTC	Fair Trading Commission
GDP	Gross domestic product
GEED	Government Electrical Engineering Department
GIS	Geographic Information System

Abbreviation	Description
GNI	Global Normal Irradiance
GOB	Government of Barbados
GTs	Aeroderivative Gas Turbines
ha	Hectares
HCEV	Hydrogen Fuel Cell Electric Vehicle
HDV	Heavy Duty Vehicle
HFO	Heavy Fuel Oil
HPS	Hydro Pumped Storage
ICE	Internal Combustion Engine
IDB	Inter-American Development Bank
EJ	Exajoules
IEEE	Institute of Electrical and Electronic Engineers
IPP	Independent Power Producer
IRRP	Integrated resource and resilience plan
kW	Kilo Watt
kWh	Kilowatt hours
LAC	Latin American and Caribbean
LCOE	Levelised Cost of Energy
LCP	Least Cost Plan
LDV	Light Duty Vehicle
LNG	Liquid Natural Gas
LT	Long Term
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LPG	Liquid Petroleum Gas
MAFS	Ministry of Agriculture and Food Security
MCA	Multi-criteria assessment
MENB	Ministry of Environment and National Beautification
METVT	Ministry of Education, Technological and Vocational Training
MESBE	Ministry of Energy, Small Business and Entrepreneurship
MDV	Medium Duty Vehicle
MIST	Ministry of Innovation, Science and Smart Technology
mmBTU	Million British Thermal Units
MOF	Ministry of Finance
MSD	Medium Speed Diesel (Engine)
MW	Megawatt
MWh	Mega Watt hours
MTWM	Ministry of Transport Works and Maintenance
NPC	National Petroleum Corporation
NPV	Net present value
OCGT	Open Cycle Gas Turbine
OHL	Overhead Line
ORC	Organic Rankine Cycle
OTEC	Ocean Thermal Energy Conversion
PEU	Project Execution Unit

Abbreviation	Description
PPA	Power Purchase Agreement
PSMP	Power System Masterplan
PV	Photo Voltaic
RB	Resiliency Bridge (power plant)
RE	Renewable Energy
RES	Renewable Energy Sources
RFP	Request for Proposal
RICEs	Reciprocating Internal Combustion Engines
RU	Research Unit
SCADA	Supervisory Control and Data Acquisition
SCO	Synchronous Condenser
ST	Short Term
STs	Steam Turbines
T&D	Transmission and Distribution
TCDPO	Town and Country Development Planning Office
TJ	Terajoules
TOR	Terms of Reference
UGC	Underground Cable
US	United States of America
USD/tCO2	United States Dollars per tonne of Carbon Dioxide
USA	United States of America
V	Voltage
VRE	Variable renewable energy
WACC	Weighted average cost of capital
W	Watt
WTGs	Wind turbine generators

Definitions

Term	Definition
Carbon Emissions	Refers to the release of Carbon Dioxide (CO_2) into the atmosphere as a result of combusting fossil fuel.
DC/AC Ratio	Oversizing of Direct Current (DC) producing PV Panels or Wind generation to the Inverter that exports Alternating Current (AC) to the grid according to the plant rating.
DigSilent Power Factory	Power simulation software supplied by DigSilent
Discount rate	Economic rate at which future cashflows are discounted to present value to consider the time-value of money.
ETAP	Power system simulation software.
Fault level	Fault level means the electrical current expected to flow into a short circuit at a stated point on the system and which may be expressed in kA or MVA. As fault levels "short out" the higher impedance load current path, fault levels tend to be very high, in the order of thousands of amperes.
Firm	Used in the context of generation technology that is dependable to cover peak demand which usually means they are dispatchable technologies, such as engines or turbines; when referring to renewable technologies the firm capacity is the capacity that represents a statistically likely level of generation that contributes to output during peak demand.
Least Cost	Least-Cost means that an optimisation problem has been solved with a minimisation of the Net Present Value (NPV) as objective value. The optimisation problem is subject to constraints within which a least-cost solution has to be identified for the problem to be feasible.
Levelised Cost of Energy (LCOE)	LCOE is a constant value that can be thought of as the average minimum price in which the electricity generated by the asset is required to be sold at, in order to offset the total costs of production over its lifetime. Although the term describes Energy in the broad sense, typically it refers to Electricity generation, which is the sense with which it is used in the context of the study.
Loss of Load Expectation (LOLE) Loss of Load Probability (LOLP)	A LOLE is a measure of the number of hours where unserved energy is experienced as a result of a supply shortfall in relation to demand on the system. Supply shortfalls are caused by inadequate generation which could be due to outages (equipment failure), lack of resources, lack of capacity, or other system constraints that prevent adequate supply (e.g., inadequate ramping). The metrics are calculated on the basis of the outputs of Short-Term modelling. A LOLP is a similar measure as LOLE, however it measures the energy unserved directly (in GWh) rather than the number of hours. The measure takes therefore the gravity of unserved energy into account but as a reliability criterion is in effect a less stringent than LOLE. LOLP and LOLE are equivalent if all unserved energy hours are full outages.
Linda Model	MESBE's Demand Forecast Spreadsheet Model
Long-Term	Represent the horizon over which assets are variables for consideration in investment and retirement decisions in planning with perfect foresight of the future
PLEXOS	Energy system simulation and optimisation software licensed by Energy Exemplar and industry standard software for energy system planning, simulation, and optimisation.

Term	Definition
Power Purchasing Parity	This concept is used to calculate an implied exchange rate under which power purchasing parities are equalised between two currencies. This is often used in economic modelling of exchange rates as income effects are considered.
Real	Real is used as opposed to nominal in the context of cashflows where real refers to the inflation corrected quantity. In economic analysis, financial parameters such as inflation are usually corrected for. For example, in the context of 3% annual inflation, an interest rate of 8% would equate to a real interest rate of 5%.
Renewable Energy	A wide definition for energy technologies that rely on energy or fuel inputs which are considered renewable, which includes Solar PV, Wind, but also Biomass and Waste to Energy.
Short-Term	Represents the horizon over which assets are fixed with limited realistic foresight to simulate system operation. The Short-Term modelling also represents the most realistic representation of real-world system behaviour.
Synchronous Generation	Synchronous generation (as opposed to asynchronous) are generators that have a rotating generator that is synchronised to the grid frequency with which the electric phases alternate. Turbine and engine technologies are usually synchronous generation. Wind and Solar PV are inverter-based and therefore asynchronous.
Thermal Generation	Thermal Generation relies on heat to drive the prime mover that rotates the generator. Typically uses a fuel as energy input to produce heat. Concentrated Solar Power is an example of thermal generation that does not use a fuel to produce heat but relies on the sun to heat up a heat exchange fluid that drives a turbine.
Variable	Used in the context of generation technology whose output is variable, implying non-firm and not dispatchable; this is the case for e.g., solar PV and Wind.
Variable Renewable Energy	A narrow definition of energy technologies that rely on variable energy inputs which includes Solar PV and Wind but not Biomass or Waste to Energy.
WACC	Weighted Average Cost of Capital is a firm's cost of capital in which each category of capital is proportionately weighted. All sources of capital, including common stock, preferred stock, bonds, and any other long-term debt, are included in a WACC calculation; or in short equity and debt.

Executive summary

Introduction

The Ministry of Energy, Small Business, and Entrepreneurship (MESBE) with funding from the InterAmerican Development Bank (IADB) has developed an Integrated Resources and Resilience Plan (IRRP) for Barbados together with Mott MacDonald. The IRRP will enable an integrated assessment of demand and supply-side options, assist MESBE in optimizing energy services and minimizing electricity costs for consumers, and ultimately develop the Ministry's capacity to undertake the IRRP process on its own. The IRRP has been developed with the Barbados National Energy Policy (BNEP) 2019 -2030 in mind. The policy aims to achieve a modern, efficient, diversified and environmentally sustainable energy sector for the island state.

The scope of work for this IRRP is summarised in Table 0.1below:

Table 0.1: IRRP Scope of Work Summary

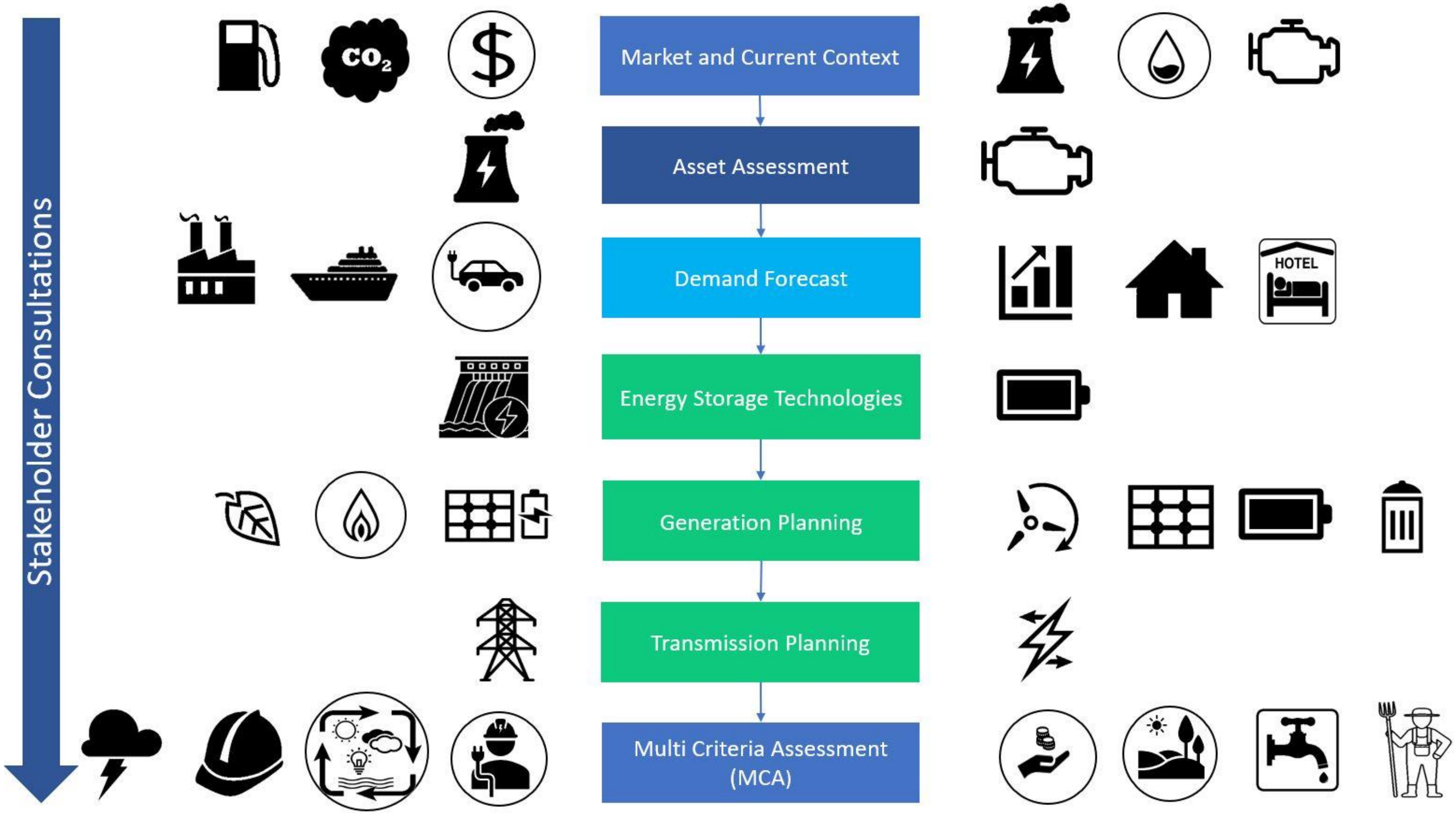
No.	Activity	Description of Activity
1	A	A diagnostic study of the challenges facing the electricity market in Barbados which could also provide inputs to develop an IRRP
2	B	Develop the IRRP
3	C	A comprehensive assessment of the technical, institutional, and organizational capacity of MESBE to undertake its new planning function, particularly as it relates to the IRRP and energy planning
4	D	Support with knowledge exchange activities between MESBE and its key energy stakeholders as it relates to the IRRP and associated sector planning

Source: Mott MacDonald derived from the IADB RFP

A Maximum Export Capacity (MEC) study was undertaken as an additional task and is not included in the above table.

Figure 0.1 below graphically describes the main steps of the IRRP study which also correspond to the scope of work of this assignment. The tasks at the centre of the figure describe consecutive steps taken to develop the IRRP where each task builds on the previous one. The icons on each side of the scope items provide a schematic representation of the topics examined in the particular task e.g., Electric Vehicles (EVs) were studied in the demand forecast study, shown to the left of the third scope item in the figure.

Figure 0.1: IRRP Flowchart



Source: Mott MacDonald

The Institutional Assessment and Capacity Building (IA&CB) task (Activity C) is not shown in the figure above as an IA&CB study is not normally part of an IRRP but was required in the context of the capacity building required for developing the first of its kind IRRP for Barbados. The MEC study is not included in the figure above for the same reason.

Summary of Key Findings

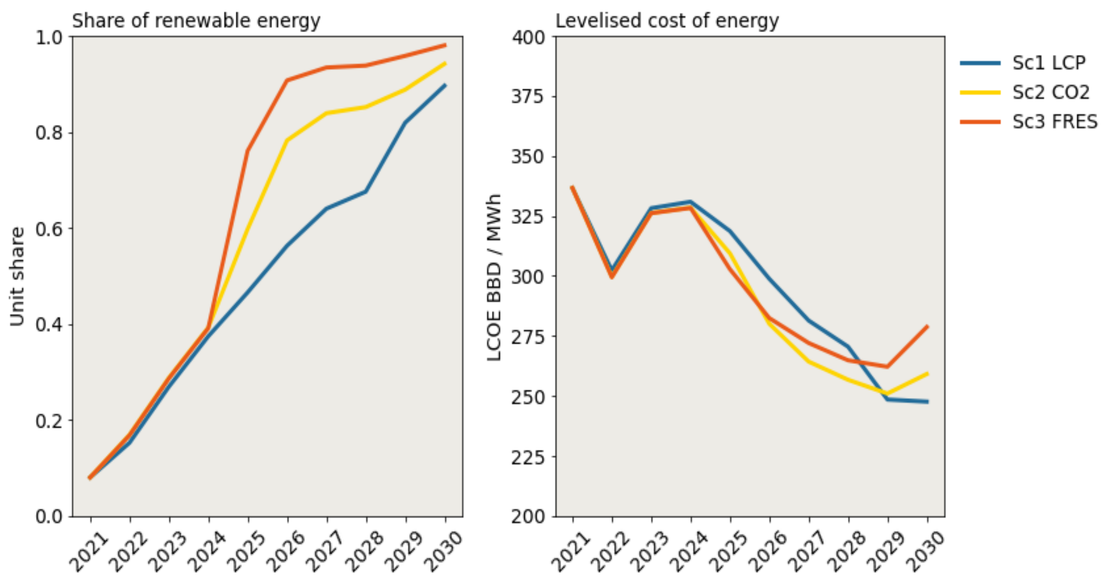
The generation and transmission planning studies span a 10-year horizon, from 01/01/2021 to 31/12/2030, and we investigated three scenarios. First is the Least-cost Plan (LCP) scenario, which is the baseline scenario without policy interventions. Second is the Carbon Cost internalised (CO2) scenario, which has a policy intervention implemented via a carbon price. Third is the Forced Firm Renewable Scenario (FRES), which has the carbon price policy and also a policy to enforce firm RES. The key findings from the studies are presented below.

The competitive position of onshore solar PV and wind in Barbados is such that substantial decarbonisation by 2030 should be expected – achieving an 88% reduction in Carbon Dioxide (CO2) emissions in the LCP scenario. The CO2 scenario and the FRES achieve 93.3% and 95% decarbonisation respectively, however this results in an additional Net Present Value (NPV) premium of 3.5% and 10.7% with respect to the LCP Scenario. None of the scenarios achieve 100% decarbonisation because back-up generation is most economically provided by existing flexible fossil fuel generators. Further decarbonisation would require increasingly higher premia.

The LCP scenario achieves a 90% share of renewables by 2030, while the FRES achieves the highest share of renewable integration (98%) and lowest cumulative emissions, but has the highest Levelised Cost of Energy (LCOE) by 2030 (see Figure 0.2). The LCOE of the scenarios diverge from the year 2023, with the higher share of renewables associated with steeper reductions in LCOE.

By 2030, the FRES increases renewables from ~90% to ~98% with a 12.5% LCOE premium on the LCP scenario. The undiscounted cumulative investment required for the three scenarios ranges between billion BBD 1.90 and 2.59.

Figure 0.2: Share of renewable energy and LCOE in the three scenarios



Results from the transmission planning study indicate additional transformers are required at key substations by 2025 and 2030, due to the existing transformers being overloaded by the projected 11 kV load growth. The overloads occurred at system maximum loading conditions. An alternative to supplying additional transformers could be to re-allocate and re-distribute loads and generation at the 11 kV level. Overall, there was an increase in system losses, which is expected as generation and loads grow, however, the losses were within the normal limits.

The voltage studies identified three key substations as suitable sites for the installation of Synchronous Condenser (SCO)s. Fault levels reduce as the number of synchronous generators decrease and the inverter-based generators and Battery Energy Storage System (BESS) increase. SCOs mitigate the reduction in fault level. BESSs provide fast frequency response for generator trips and Variable Renewable Energy (VRE) intermittency. The geographical distribution of generation, BESSs, and SCOs and other measures such as electrical islanding and replacement of Overhead lines (OHLs) will assist in improving future system resilience.

The current electricity market context and diagnostic

Barbados' total primary energy consumption is around 15 Exajoules (EJ) (or 15,000 Terajoules [TJ] or 4,200 GWh). This level of consumption is about the same level as the early 1990s while energy intensity of GDP peaked in 2009 and is now near the lowest levels observed over the past three decades. The transport sector is currently the largest end user of primary energy with a 50% share in total energy use.

Most of Barbados' energy is imported, although the country does produce crude oil, natural gas, and biomass. Over the period 1990 to 2019, oil products have been the dominant energy type in Barbados which currently account for 92% of primary energy use. Natural gas accounts for about 5% of primary energy use, with renewables meeting just 3%.

Given the implications in terms of price exposure to world oil markets, foreign currency accounts, local, and global emission contributions, and security of supply, the Government of Barbados (GoB) has set a target to transform the energy landscape and shift the country away from oil. The shift is set out based on the acknowledgement that Barbados has significant renewable energy potential, which is addressed further in this report.

Oil is mainly used in transport (which accounts for almost half of final end use) and in power generation, which shares most of the remainder of fuel input with bunker or marine oil. Clearly, transport and electricity generation are two of the key target decarbonisation areas. Bioenergy, natural gas, and primary electricity (from solar) all play a minor role to date.

Asset Assessment

We have carried out an assessment of key performance information of existing power generation assets in Barbados in relation to normal industry standards. The condition, age, and performance as well as the context of the BNEP 2019-2030, have informed the assumptions for retirements and life-extension included in the development of the generation planning study. The most important drivers to retire or life-extend are the plant economics and reliability.

Key findings are:

- Units S1 and S2, the steam plants at Spring Garden, are 44 years old and, based on age alone, would be expected to retire within the next six years. However, these units show very low reliability and are expensive to operate at this point while their technical capabilities are not in line with the requirements for increasing renewable penetration. The recommendation would be to retire these units as soon as possible;

- The Low-Speed Diesel units (D11-D15), also at Spring Garden, range in age between 15 and 38 years. These units are a little less reliable than would normally be expected while their efficiency is in line with expectations. It would be expected that all of these units, but certainly the younger ones, could still provide one or two decades of reliable service. Noting that it is generally possible to convert such units to be fired with liquid biofuels, this has been considered as an option in the generation planning study;
- The GTs at Seawell power station are between 18 and 24 years old, and the GTs at Garrison and Spring Garden are 30 and 47 years old, respectively. Although with a typical design life of 25-30 years the Seawall units have another 6-12 years of life remaining, the Garrison units demonstrate that they can be kept in service for much longer. These units are not suitable for continued operation but ideal for back-up and emergency generation. Unfortunately, these units cannot be converted to renewable fuels. It is recommended that the option is retained to consider these units specifically for back-up use in the generation planning study.

Demand Forecast

This report presents a demand forecast that provides a comprehensive view of the electricity demand evolution in Barbados up to 2040. The demand forecast is based on two main components: MESBE's forecast of the current electrified sectors and Mott MacDonald's forecast of the newly electrified sectors and potential energy savings. Using Autoregressive Integrated Moving Average (ARIMA) intervention analysis on real GDP and electricity demand, MESBE has forecasted the demand in the commercial, hotels & restaurants, industry, and residential sectors. Using a bottom-up methodology, Mott MacDonald has forecasted the demand of newly electrified sectors (Electric Vehicles (EVs), Cruise Liners (CLs), and cooking), and energy savings from Demand Side Management (DSM) and Energy Efficiency (EE).

The demand forecast has been developed for three scenarios: Base, High and Low. The key assumptions underpinning the Base Scenario are: COVID-19 impact on the economy, tourism, and international travelling, 60% EV market share by 2030, four electric CLs in port during the cruise season by 2030, the gradual replacement of cooking appliances from gas to electric, and moderate DSM savings.

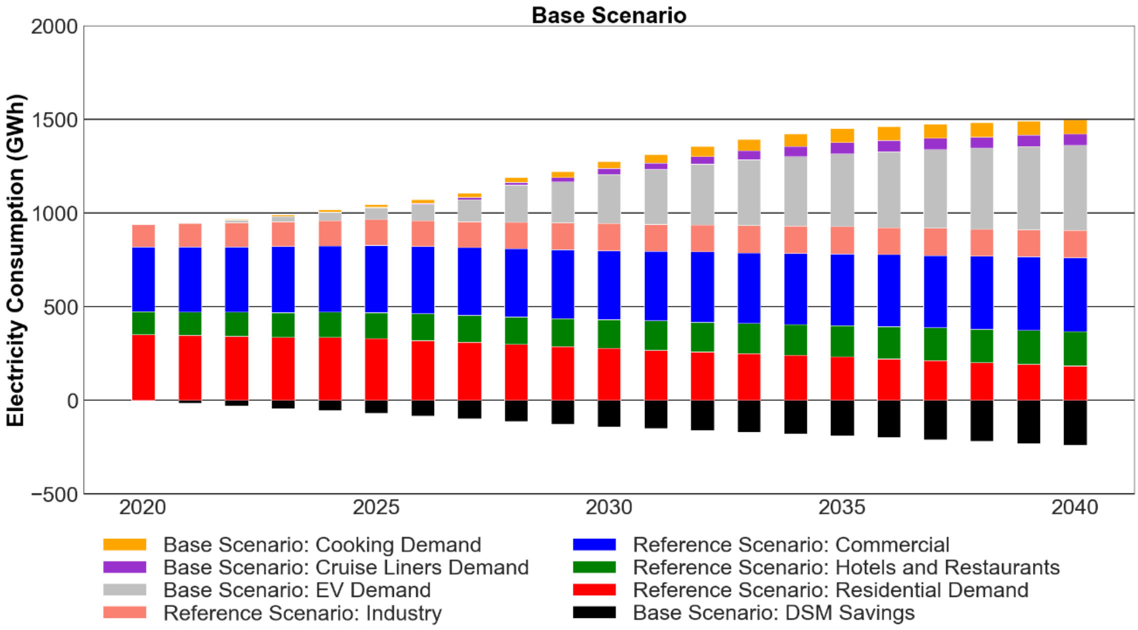
Electricity demand in Barbados is projected to increase to 1277 GWh in 2030 and 1499 GWh in 2040 under the Base Scenario, which is a 35% and 59% increase respectively from its 2019 levels. The commercial and residential sectors currently account for the largest share of electricity demand (37% each), however, this status is expected to change by 2030, with the commercial and residential sectors share dropping to 32% and 29% respectively. On the other hand, the industry and hotels & restaurant sectors are projected to have an almost constant share (12%) of the annual demand from 2019 and 2030.

The transport sector will see the biggest increase in demand with 264 GWh in 2030 in the Base Scenario, with the majority of the EVs expected to be private cars. This newly electrified transport sector could account for 21% of the total demand of the country by just 2030.The gradual replacement of gas cooking to electric and the electrification of CLs, could collectively account for 5% of the total demand in the 2030 Base Scenario. DSM savings through EE measures could reduce total demand by 11% in the 2030 Base Scenario. Figure 0.3 shows the demand projections for the Base Scenario by sectors and highlights the impact of underlying demand projections and EV demand, particularly from 2030 onwards.

Barbados' future power demand will be closely linked to economic drivers but will also be influenced by electrification of new sectors currently served by fossil fuels, most notably the road transport sector. The power demand from 2020 till 2030 will continue to be mainly driven by the commercial and residential sectors, with EVs having a significant share from 2030 till

2040. At the same time, we can also expect to see more slow-acting saturation effects and EE changes in some end-use sectors and potentially more rapid policy-driven changes from DSM/EE programs. All these factors have been considered in framing the demand forecast.

Figure 0.3: Projected electricity demand by sector (Base Scenario)



Source: Mott MacDonald

Resource Supply Options

A preliminary analysis on the economic feasibility of energy supply options has been conducted (screening curve analysis) and technologies were assessed on the basis of their LCOE. The results have shown that liquid biofuel options are generally not economically feasible due to their expected high cost. Renewable Energy (RE) technologies appear to be the most attractive options with solar being the most economical and wind coming second. Thermal technologies follow in the merit order; however, their economic viability depends on their utilisation profile i.e., whether they are used for peaking i.e., Gas Turbines (GTs) or for baseload i.e., Internal Combustion Engines (ICEs). Additional analysis on the RE resource has shown great potential for these technologies in terms of resulting annual energy yield, but also highlighted the short-term output variability that presents challenges in balancing demand and supply.

Energy Storage Technology Study

While many storage technologies such as Hydro Pumped Storage (HPS), Compressed Air Energy Storage (CAES), and thermal based systems have been developed, many are still limited with respect to their response capabilities, siting, and capacity flexibility. Electrochemical energy storage is capable of meeting a far wider range of capability than many alternatives and this capability is developing rapidly as battery storage is seen as very much the future across a range of applications from transportation to electrical grid systems. BESSs have a long track record of implementation for grid applications and costs have recently been in rapid decline while performance and life expectancy continue to increase.

At the moment, Lithium Ion (Li-Ion) BESSs are the only mature and proven technology which can cover the whole range of required storage applications. This may change as technology development advances and feasibility studies shed more light on the options available to Barbados. Other storage technologies such as HPS and CAES require more detailed geological and siting studies before they can be considered feasible energy storage options for Barbados. In the near term, for bulk storage application, HPS could be competitive option, and in the future Flow Batteries and CAES may become suitable options. From a resiliency and transmission network perspective, modular, and distributed solutions would be preferred, which currently leaves only Li-Ion BES as a bankable option.

Generation Planning Study

The generation planning horizon spans over 10 years (2021-2030), coinciding with the BNEP 2019-2030 timeframe. Three scenarios investigated are:

Table 0.2: IRRP Scenarios

ID	Scenario	Description
1	Least-cost plan (LCP)	Baseline scenario without policy intervention for reference. Carbon is priced for accounting purposes but otherwise externalised, i.e., not a driver for build and dispatch decisions.
2	Carbon Cost internalised (CO2)	Policy intervention implemented via a Carbon Price. The Carbon Price is internalised into build and dispatch decisions.
3	Forced Firm Renewable Scenario with Carbon Cost internalised (FRES)	Policy intervention implemented via a Carbon Price. The Carbon Price is internalised into build and dispatch decisions. In addition, firm renewable resources are enforced into the plan as follows: • A maximum of two Biomass plants of 10 MW each or a minimum of one Biomass Plant of 10 MW can be built, one of which must be built by 2025 • A maximum of five Landfill Gas plants of 1 MW each can be built from 2023 and must be built by 2025. • A maximum of one Waste to Energy plant of 8 MW can be built from 2023 and must be built by 2025. A choice must be made between a baseload or a more flexible technology type

Source: Mott MacDonald

The scenarios were supplemented by a sensitivity analysis to identify the impacts that uncertain variables such as load, capex, WACC, fuel price and carbon price would have on the robustness of the expansion plans.

Key economic assumptions used include an exchange rate of 2.2:1 BBD: USD (based on Power Purchasing Parity (PPP)). A real discount rate of 2%, and a real Weighted Average Cost of Capital (WACC) of 5% was used in the base case. A carbon price starting at 80 USD/tCO2 in 2020 and increasing to 100 USD/tCO2 in 2030 was used. Fuel prices were determined by the latest Energy Information Administration (EIA) forecast with basis adjustments made to reflect handling and delivery charges. Biodiesel is assumed to be available at an 88% premium (with a 2% increase per annum) to diesel.

We have used PLEXOS, an industry leading optimisation and simulation software to conduct the expansion modelling, licensed by Energy Exemplar. The generation planning methodology included generation adequacy modelling.

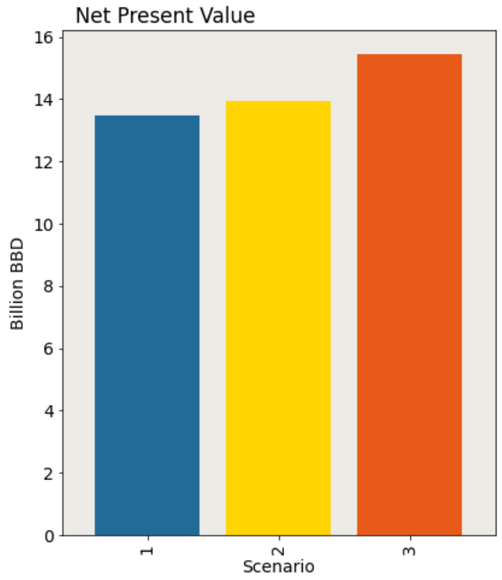
The retirement date for existing generation units were optimised as per the asset assessment recommendations and in the interest of the overall optimisation of the generation plan. Existing ICE Units D13, D14, D15 were also considered as potential conversion candidates to operate on biofuel, which was proven uneconomic in most cases.

Primary and secondary reserves were co-optimised, the latter of which can also be provided by smart (interruptible) EV loads. A 50% share of smart charging was assumed (and a 100% for the high demand case). Other system constraints were modelled and optimised including at least one synchronous generation unit required to provide the reference frequency for the grid and SCO units to provide necessary grid support services.

The results highlight the competitive position of RE in Barbados even for the Least Cost Plan (LCP) Scenario 1, where carbon emission costs are included, and the power system achieves an 88% reduction in CO2 emissions in 2021 by 2030. This is because solar PV and onshore wind generation are clearly on the least cost development path even including the necessary BESSs for back-up and grid balancing. This is evident from the capacity additions for these technologies being very similar across scenarios.

Scenario 3 achieves the highest emissions reduction, down to 5% of current levels by 2030, as a result of the additions of the firm renewables (waste to energy, landfill gas, and biomass). These albeit expensive generation technologies allow for additional retirement of existing thermal plants, which are otherwise required to remain on the system to provide occasional back-up power.

Figure 0.4: Net Present Value Overview



Source: Mott MacDonald

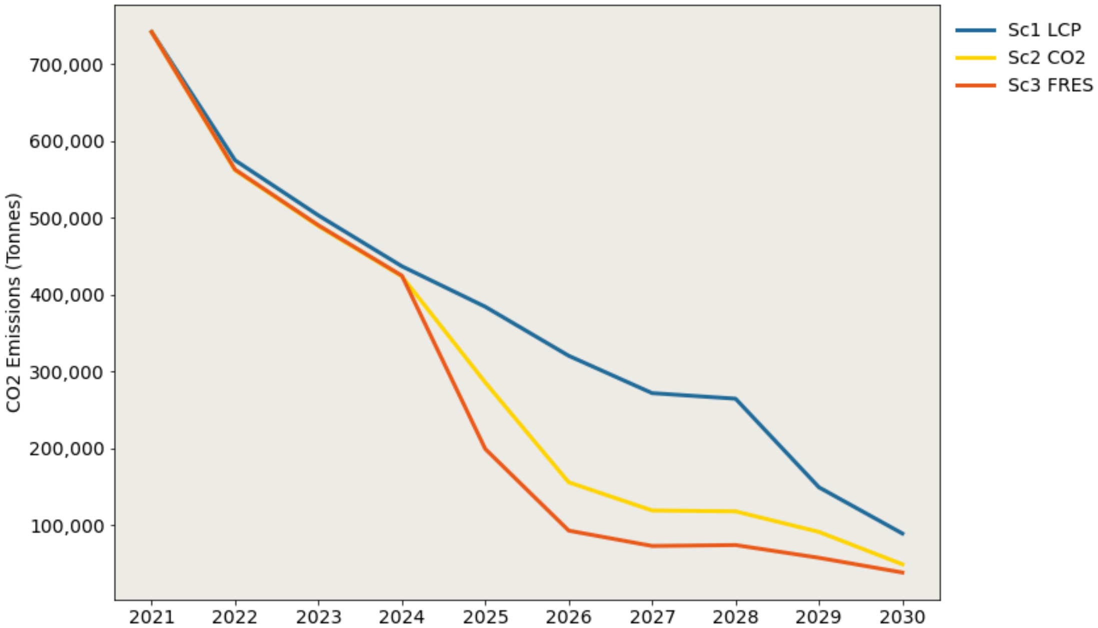
It is also evident that the cost of carbon emission reductions face decreasing marginal returns, which is generally a well-known phenomenon. None of the scenarios achieved a 100% decarbonisation as set out in the BNEP 2019-2030 and it would require increasingly higher premia to achieve this. The Net Present Value (NPV) of Scenario 2 and 3 are 3.5% and 14.5% higher than the least-cost plan, Scenario 1.

The build-out in RE requires significant land take such that by 2030 Scenario 2 and 3 will utilise just over 70 000 acres (excluding agricultural land use for fuel crop production).

The undiscounted cumulative investment over the study horizon needed to achieve Scenario 2 and Scenario 3 is estimated at Billion BBD 2.27 and 2.59, respectively compared to 1.90 in the LCP. As seen, however, against this are significant reductions in fuel imports that are achieved by the more aggressive decarbonisation scenarios.

The LCOE of the system divides total costs (operational and investment related) by total generation each year and is an approximation of generation tariffs; it is expected to benefit from the energy transition with a decline by 18% to 27% depending on scenario and horizon, with the LCP achieving the largest decline.

Figure 0.5: Decarbonisation Pathways - Annual Carbon Emissions



Source: Mott MacDonald

Transmission Planning Study

The Transmission planning studies were undertaken after the demand forecast and generation planning studies were completed as both these studies have a direct impact on what new transmission infrastructure is required.

Transmission studies and masterplan studies need to satisfy two planning objectives:

1. System limits met in steady state;
2. System limits met in stability state.

With reference to the first objective, the transmission system was successfully planned from 2021 to 2030 meeting both normal condition ((N-0) and emergency (N-1) system conditions).

Additional transformers are however required at Substation 12, Substation 14, Substation 13, Substation 11, Substation 3, and Substation 10 in 2025 and 2030. These additional transformers are required due to the existing transformers being overloaded by the projected 11 kV load growth except at Substation 14 where the transformer overload was due to high generation levels being evacuated from the Substation 14 11 kV bus. The overloads occurred at system maximum loading conditions. An alternative to supplying additional transformers could be to re-allocate and re-distribute loads and generation at the 11 kV level.

Voltage studies identified Substation 12, Substation 4, and Substation 15 as suitable substations for the installation of Synchronous Condensers (SCOs).

Cruise liner loads were successfully supplied from Substation 15 in 2025 and via a new “Port” 24.9/11 kV transmission supplied by Substation 15 and Substation 12.

There was an overall increase in system losses as the system evolved towards 100% RE penetration. This is to be expected as generation and loads grow. The overall system losses when measured against the total system generation fall within normal transmission loss limits.

Fault levels reduce as VRE penetration increases which is to be expected as the number of synchronous generators decrease and inverter-based generators and BESSs increase. SCOs maintain fault levels to acceptable levels for system max and system minimum conditions for the study years: 2025 and 2030.

In 2021, for the trip of the largest generating unit in Barbados, Under Frequency Load Shedding (UFLS) is invoked to keep the system frequency-stable. The system is frequency stable for the years 2025 and 2030 for the trip of large generators, without the need for UFLS operation as new synchronous generating capacity, VRE generation capacity, SCOs, and BESSs are installed. The BESSs successfully supply fast-acting real power (MW) support and the SCOs provide inertia and dynamic voltage support. The BLPC system is transiently stable after the application of a 120 ms line fault and line trip for the years 2021, 2025, and 2030.

The geographical distribution of synchronous generation, VRE generation, BESSs, and SCOs will assist in improving future system resilience. Electrical islanding of the Barbados Integrated Power System (IPS) will be more achievable where generation and loads are comparable across the system. Further work and studies are recommended to strengthen the design of the power system to be more resilient for extreme weather events. Such resiliency solutions could include inter alia: conversion of overhead lines to underground cables, raising of important power station or substation sites, or flood protection mitigation.

Following the IRRP, further studies are recommended such as protection studies as fault levels change, harmonic studies as the penetration of inverter-based generation and energy storage technologies are connected, equipment resilience feasibility studies for extreme weather events, re-purposing of existing thermal generating plants to be able to operate in SCO mode, and the implementation of an Automatic Generator Control (AGC) system for the island.

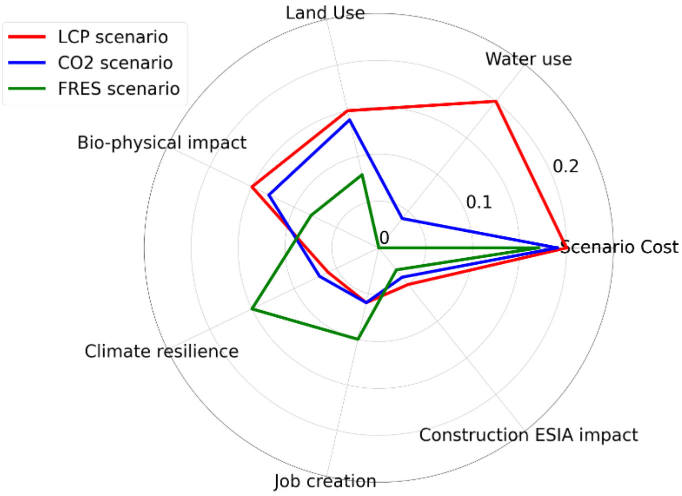
Multicriteria Assessment (MCA)

A Multicriteria Assessment (MCA) has been carried out to help inform the transition to a more sustainable electricity system in Barbados. The MCA evaluates quantitative and qualitative criteria beyond the generation and transmission NPV analysis and attempts to find the best scenario for Barbados.

The three generation planning scenarios are ranked based on seven economic, social, and environmental criteria. The seven criteria and their weights are: scenario cost (20%), land use (20%), water use (20%), bio-physical impacts (15%), climate resilience (15%), job creation (10%), construction ESIA impacts (5%). These seven criteria and their respective weights which reflect their level of importance were assigned following several stakeholders' interactions and comments.

The MCA results shows that the LCP scenario has the highest ranking and is therefore the best option for Barbados, based on scenario cost and land use having the highest importance of all the seven criteria. The CO2 scenario ranks second while the FRES ranks third, and this mostly due to the FRES's comparatively higher land and water requirements for biofuel crop cultivation. The MCA final score of the three generation planning scenarios in the seven criteria are presented in Figure 0.6. The figure highlights the relationships between the economic, social, and environmental criteria in each scenario.

Figure 0.6: Normalised final criteria scores for the three main generation planning scenarios



Source: Mott MacDonald

Four sensitivity analyses were carried out in order to assess how the three scenarios rank under weights that place more importance on social and environmental criteria. For one of the environmental and social sensitivities, land-use for biomass production is considered to be positive. The rationale for this is that there is substantial fallow land due to the decline of the sugar industry, and a number of stakeholders commented that revitalising the old farmland and putting it under crop cultivation would have significant long-term benefits in terms of land preservation and food security.

The sensitivity results show that the LCP scenario has the highest ranking in all sensitivity cases except for Social Sensitivity 2. The FRES has the highest ranking if job creation is the most important criterion to the decision makers, and land use for biofuel crop cultivation is viewed as a positive criterion. The CO2 Scenario is never ranked the highest and has the second position only in the base case and when the four environmental criteria are given more importance than the other three criteria.

The MCA process has highlighted the importance for policy-makers in Barbados to investigate inter-sectoral interactions and dependencies. The ranking of electricity planning scenarios is strongly influenced by the weightings of the different cross-sector criteria. Therefore, the planning for the electricity sector should not be undertaken in isolation, and its interactions with other sectors such as transport (EV), agriculture (biofuel crops), and tourism (cruise liners), should be assessed. We therefore recommend a cross-sector working group be established to analyse and agree planning criteria and priorities.

Introduction

1 Introduction

The Ministry of Energy, Small Business, and Entrepreneurship (MESBE) with funding from the InterAmerican Development Bank (IADB) has developed an Integrated Resources and Resilience Plan (IRRP) for Barbados together with Mott MacDonald. The IRRP will enable an integrated assessment of demand and supply-side options, assist MESBE in optimizing energy services and minimizing electricity costs for consumers, and ultimately develop the Ministry's capacity to undertake the IRRP process on its own.

1.1 Scope of Work

The scope of work for this IRRP as per the Request for Proposal (RfP) is included in Appendix A.1 and is summarised in Table 1.1 below:

Table 1.1: IRRP Scope of Work Summary

No.	Activity	Description of Activity
1	A	A diagnostic study of the challenges facing the electricity market in Barbados which could also provide inputs to develop an IRRP
2	B	Develop the IRRP
3	C	A comprehensive assessment of the technical, institutional, and organizational capacity of MESBE to undertake its new planning function, particularly as it relates to the IRRP and energy planning
4	D	Support with knowledge exchange activities between MESBE and its key energy stakeholders as it relates to the IRRP and associated sector planning

Source: Mott MacDonald derived from the IADB RFP

A Maximum Export Capacity (MEC) study was undertaken as an additional task to the Contract. An MEC study investigates the generation export limits at BLPC Transmission substations before system limits are violated.

1.2 Layout of the Final IRRP Report

This Final Report presents the methodology, findings, and conclusions of the IRRP study. The layout of the Final IRRP Report is outlined below:

Table 1.2: Layout of IRRP Report

No.	Activity	Chapter	Description of Chapter
1	B	1	Introduction
2	A	2	Current electricity market context and diagnostic
3	B	3	Asset Assessment
4	B	4	Demand Forecast
5	-	5	Resource Options Evaluation
6	-	6	Energy Storage Technology Study
7	-	7	Generation Planning Study
8	-	8	Transmission Planning Study
9	-	9	Multi-Criteria Assessment Study
10	-	10	Discussion and Recommendations
11	-	11	References
12	-	12	Appendices

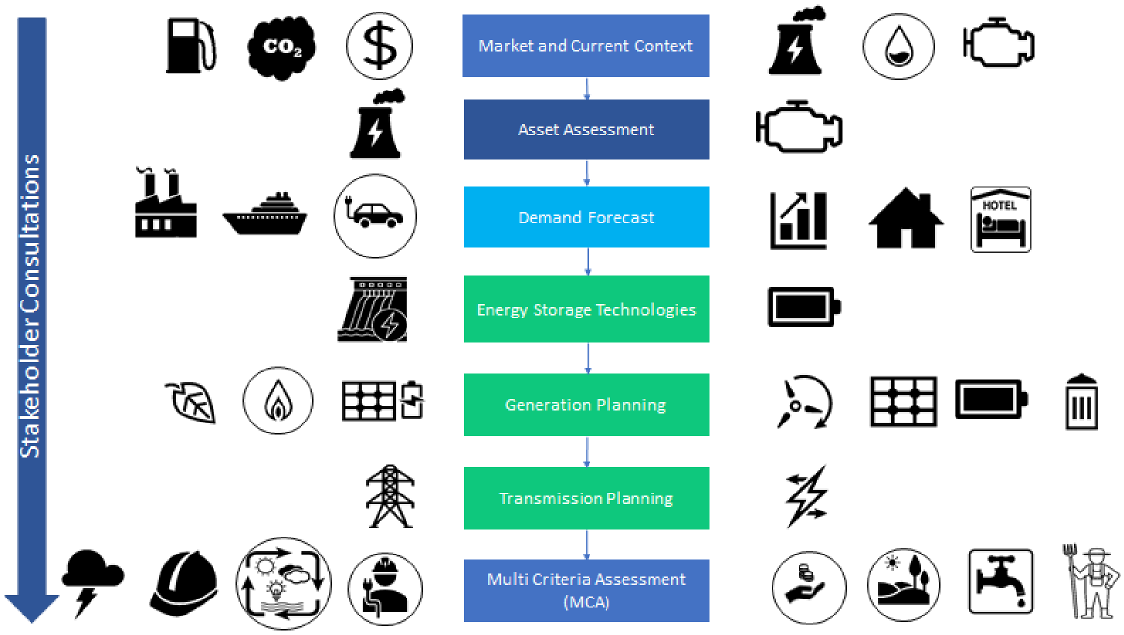
Source: Mott MacDonald

Conclusions to the analysis are included at the end of each chapter while recommendations arising from the IRRP study are captured in its own chapter at the end of the report, i.e., Chapter 10.

1.3 IRRP Study Methodology Flowchart

Figure 1.1 below graphically describes the main steps of the IRRP study which also correspond to the scope of work of this assignment. The tasks at the centre of the figure describe consecutive steps taken to develop the IRRP where each task builds on the previous one. The icons on each side of the scope items provide a schematic representation of the topics examined in the particular task e.g., Electric Vehicles (EVs) were studied in the demand forecast study, shown to the left of the third scope item in the figure.

Figure 1.1: IRRP Methodology Flowchart



Source: Mott MacDonald

The Institutional Assessment and Capacity Building (IA&CB) task (Activity C) is not shown in the figure above as an IA&CB study is not normally part of an IRRP but was required in the context of the capacity building required for developing the first of its kind IRRP for Barbados. The MEC study is not included in the figure above for the same reason.

Market Context

2 The current electricity market context and diagnostic

2.1 Current energy context

Barbados is a small island state with comparatively limited indigenous resources which has therefore meant an almost total dependence on imported oil products to meet its energy demand.

This section provides a descriptive analysis of the demand and supply historical trends for each energy type, from main petroleum products to biomass and electricity as well as key significant assets such as power stations and gas production facilities. Further, it presents energy use by end-use sectors including industrial, commercial, residential, transport, agricultural, and others (noting the role of cruise liners).

Given the implications in terms of price exposure to world oil markets, foreign currency accounts, local, and global emission contributions, and security of supply, the Government of Barbados (GoB) has set a target to transform the energy landscape and shift the country away from oil. The shift is set out based on the acknowledgement that Barbados has significant renewable energy potential, which is addressed further in this report. Reductions in capital costs of renewable generation and electricity storage equipment, growing confidence in the performance of such technologies (including the coming of age of electric vehicles (EVs)), along with heightened concern from wider stakeholders in relation to climate change risks (Paris agreement commitments)[1] has recently reinforced the desire to decarbonise Barbados' power and transport sectors by 2030.

The shift is set out in the Barbados National Energy Policy 2019-2030 (BNEP 2019-2030) [2] document which states six transformational goals as follows:

1. Provision of reliable, safe, affordable, sustainable, modern, and climate friendly energy services to all residents and visitors;
2. Zero domestic consumption of fossil fuels economy wide;
3. Export of all hydrocarbons produced both on land and offshore;
4. Maximising local participation (individual and corporate) in distributed Renewable Energy (RE) generation and storage (democratisation of energy);
5. Minimise the outflow of foreign exchange;
6. Creating a regional centre of excellence in RE research and development;

In order to achieve these transformational goals in the next 10 years Barbados will need to undergo a rapid transformation of its power and transport sectors.

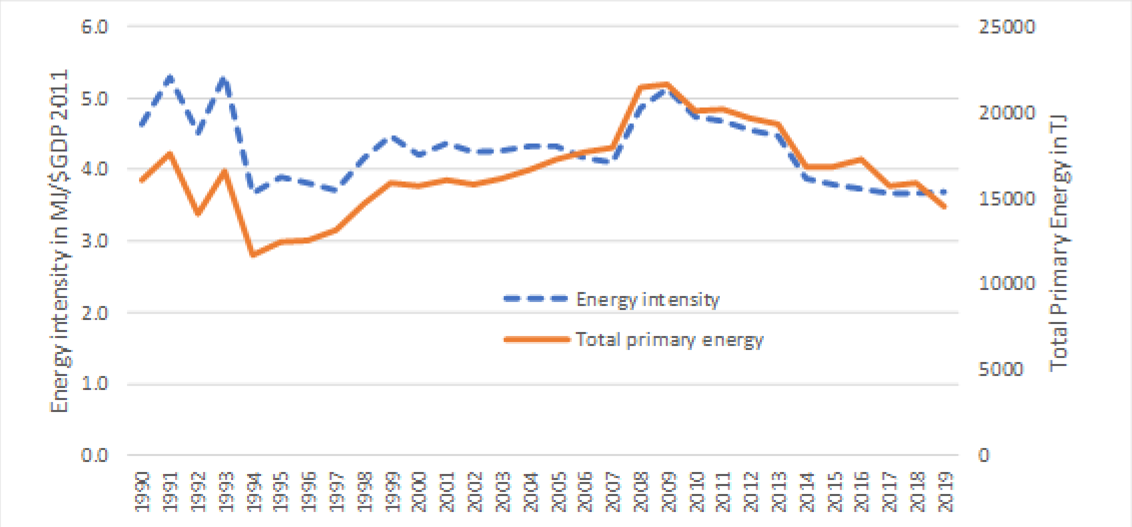
2.1.1 Overall energy demand and supply trends

Barbados' total primary energy consumption is around 15 Exajoules (EJ) (or 15,000 Terajoules [TJ] or 4,200 GWh) [45]. This level of consumption is about the same level as the early 1990s – see Figure 2.1. The figure shows that consumption increased from the mid-1990s to 2009, when it reached almost 22 EJ after which the trend has been downward. The figure also shows the overall energy intensity (the annual energy to produce a US dollar of GDP) saw a rising trend

[1] Barbados Nationally Determined Contribution intends to achieve an economy-wide reduction in GHG emissions of 44% compared to its business as usual (BAU) scenario y 2030. In absolute terms, this translates to a reduction of 23% compared with the baseline year, 2008. As an interim target, the intention will be to achieve an economy-wide reduction of 37% compared to its business as usual (BAU) scenario by 2025, equivalent to an absolute reduction of 21% compared to 2008.

between 1994 and 2009, but then a declining trend since 2009 - falling 28% in the last decade. The strong growth from the 1990s to 2009 was driven by the commercial and transport sectors, with electricity and oil being the main energy carriers, respectively.

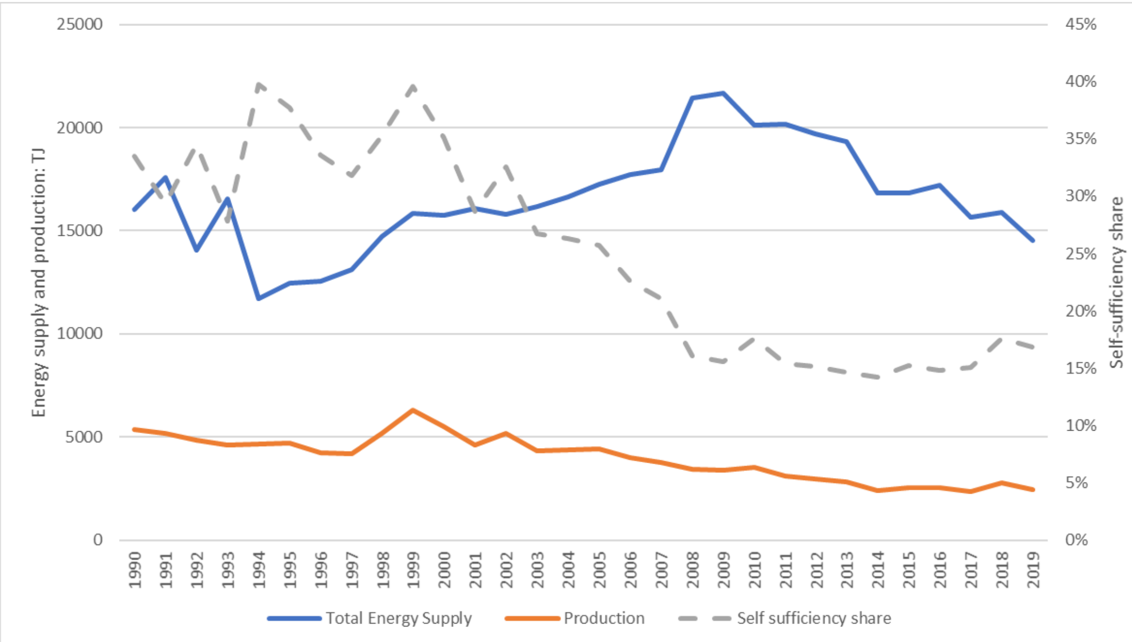
Figure 2.1: Total primary energy consumption and energy intensity: 1990 to 2019



Source: UN Energy Statistics [45] and Barbados Statistical Service

Most of Barbados' energy is imported, although the country does produce crude oil, natural gas, and biomass. The share of energy produced indigenously as a proportion of total energy supply has fallen since 1990, from 34% to 15-17% in recent years [45]. The share had initially risen peaking at about 40% in 1999 but since then it has been on a steady decline – see Figure 2.2. This decline reflects the reduction in bio-energy production as sugar production has declined.

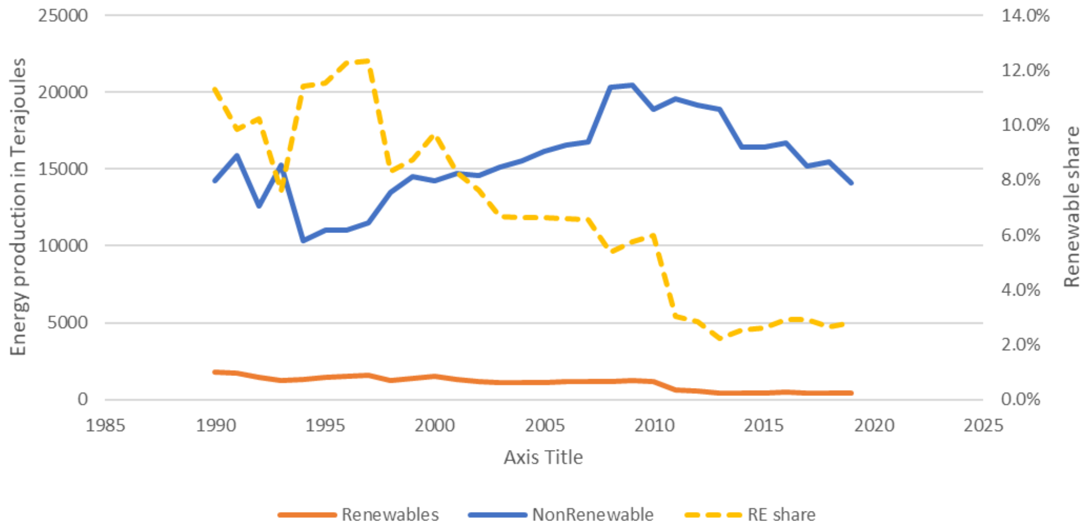
Figure 2.2: Total energy use, production, and self-sufficiency 1990-2019



Source: UN Energy Statistics [45] and Barbados Statistical Service

The decline in the bio-energy production has led to a decline in the share of renewable energy (RE) in total primary energy consumption, which has seen the share fall from about 12% in 1996/1997 to just over 2% in 2013 and then recover to about 2.5% as shown in Figure 2.3 [45]. This shows that the growth of solar generation in recent years has so far had negligible impact on increasing the share of renewables in the generation mix of Barbados.

Figure 2.3: RE and non-RE production, and share split 1990 to 2019



Source: UN Energy Statistics [45] and Barbados Statistical Service

2.1.2 Energy use by fuel

Over the period 1990 to 2019 oil products have been the dominant energy type in Barbados with their share hovering around 60%; refer to Appendix B for further information. Gas's share of the total has also been fairly stable, at a much lower level of 2.0-3.5%. The main shift in the fuel mix has been a reduction in bioenergy and waste use from about 20% of total final energy use in 1990 to around 10% in 2007 and 2% in 2019. As mentioned above this reduction in bio-energy use reflects the decline in the sugar industry, which mean the by-products/residues were no longer being produced.

2.1.3 Energy use by sector

The shift in fuel mix in final energy use has been matched by significant shifts in the end user mix. The main features in this end user mix are the relative decline of manufacturing (industrial) and household (residential) demand at the expense of increasing commerce (commercial) and transport demand; refer to Appendix B for more information.

Transport is currently the largest end user. From 1990 to 2019, transport's share in total use has increased from 38% in 1990 to about 50% in 2019.

The commercial sector had seen strong growth from 1990 to 2007, a level which it broadly maintained until 2017 after which its share has fallen sharply. Commercial's share of total final energy increased from 3% in 1990 to 20% in 2007, a level which it has broadly maintained since then.

Residential is the third largest user group having recently overtaken industrial. Overall residential energy share increased from 22% in 1991 to hit 25% in the late 1990s before slipping to 12-13% in 2008-2014 and then recovering to 15-16% in 2018-2019 [45].

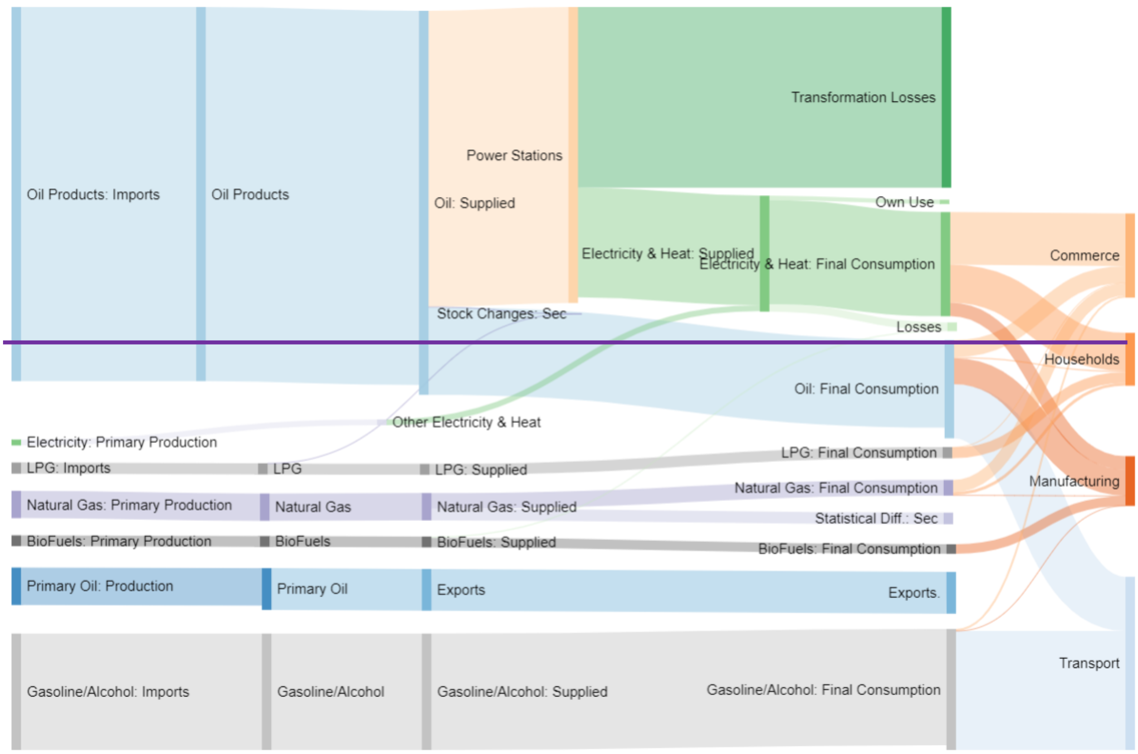
Manufacturing has seen the most marked change with absolute consumption falling by 60% between 1990 and 2019, and its share in total final energy use falling from 41% to 12%. This reduction in industrial energy use reflects the decline in industrial production and a shift towards lower energy intensity activities.

2.1.4 Energy balance and Sankey diagram

The energy balance in Barbados for 2019 can be represented in a Sankey diagram as shown in Figure 2.4 below. In a single figure, the energy balance provides a narrative of the whole supply and demand situation for all the energy types and sectors, including the transformation sectors, such as power generation and refining, and losses along the supply chain.

Clearly, imported oil fuels (large blue bar on the left of the Sankey diagram) dominate energy supply. Transport (blue bar on the bottom right) and power generation, and generation losses (green bars on the top right) dominate energy demand.

Figure 2.4: Barbados Energy Balance Sankey Diagram



Source: Mott MacDonald from MESBE Energy Balance Data

The key feature to note from the Sankey diagram above is the absolute dominance of oil in the Barbados energy economy. This oil is mainly used in transport (which accounts for almost half of final end use) and in power generation, which shares most of the remainder of fuel input with bunker or marine oil. Clearly, transport and electricity generation are two of the key target decarbonisation areas. Oil products are all imported, with Barbados exporting a small quantity of crude oil. Bioenergy, natural gas, and primary electricity (from solar) all play a minor role.

Transformation losses are a result of the low efficiencies of thermal power plants. With the evolution to renewable generation, transformational losses will substantially reduce.

The sectors show a diversity of supply pattern, but Barbados' primary energy use shows the dominance of oil products, which accounts for 92% of the total. Natural gas accounts for about 5% of primary energy use, with renewables meeting just 3%. The mix of oil use shows a broad range of oil products are used ranging from heavy fuel oil (HFO) through the middle distillate products (diesel and kerosene) to the lighter products of gasoline and finally LPG. HFO is the number one oil product (at 36% of total oil use), with this being largely accounted for by power generation, while kerosene/jet fuel, and gasoline both account for about 22%, mainly in power generation and transport, respectively.

Further details to support the analysis presented here can be found in Appendix B.

2.2 Regulatory framework and market structure

2.2.1 Overview

The Barbados regulatory framework is fairly light touch, which is typical of many small island states. That said the GoB does hold a key interest in the oil sector, through its ownership of the Barbados National Oil Company Limited (BNOCL) and the National Petroleum Corporation (NPC). Private oil companies do not participate in oil or gas production or in imports, but rather as oil product distributors and retailers.

The electricity sector is dominated by a privately owned vertically integrated utility, BLPC, which is wholly owned by a Canadian based energy holding company. BLPC operates under a long-term concession or license agreement. BLPC's role includes important functions such as being the generator of last resort and the transmission system operator (TSO), and distribution system operator (DSO).

Barbados' oil and gas (O&G) sector operates largely as a private company would – adopting market pricing. The main exception is for natural gas which is produced along with crude and has traditionally been sold at sub-market prices (i.e., prices below competing fuels).

BLPC faces regulation in terms of the capital expenditure it can recover from customers and the tariff level, with all this being regulated by the Fair-Trading Commission (FTC). There is an automatic fuel price adjustment mechanism which allows BLPC to recover and pass-on changes in imported fuel prices.

In recent years there has been a growing interest in decentralised electricity generation, both at the household level (based on increasingly affordable roof-top PV), and also for MW scale distribution or transmission connected PV generation. This has been encouraged under the Feed in Tariff (FiT) arrangement, including a scheme called the Renewable Energy Rider.

The GoB is now in the process of exploring new regulatory and market models for opening up the energy business, especially for electricity generation, storage, and independent supply.

2.2.2 Entities involved in the Barbados sector

Table 2.1 below provides a high-level listing of the entities involved in Barbados' energy sector, including the key governmental agencies responsible for overseeing activities.

Table 2.1: Functions, components, and entities in the energy sector

Key Function	General Components	Entities
Energy Sector Law, Policy, and Governance	General coordination and oversight. Public policy, legislation	Ministry of Energy, Small Business, and Entrepreneurship (MESBE) The Parliament of Barbados

Key Function	General Components	Entities
Energy Resource Protection and Management	Identify and manage conventional and RE resources.	Ministry of Energy, Small Business and Entrepreneurship (MESBE) Coastal Zone Management Unit (CZMU) Environmental Protection Department (EPD) Ministry of Maritime Affairs and the Blue Economy (MMABE) Town and Country Planning Office (TCPO)
Regulation of Energy Production and Supply	Technical, economic, and environmental regulation.	Ministry of Energy, Small Business, and Entrepreneurship (MESBE) Barbados National Standards Institution (BNSI) Electric Light and Power Act Advisory Committee (ELPAC) Environmental Protection Department (EPD) Fair Trading Commission (FTC) Government Electrical Engineering Department (GEED) Ministry of Transport, Works, and Maintenance (MTWM)
Energy Production	Exploration, production, and wholesale trade of electricity, natural gas, and liquid fuels	Barbados Light and Power Company Limited (BLPC) Ministry of Energy, Small Business, and Entrepreneurship (MESBE) Independent Power Producers (IPPs) Barbados National Oil Company Limited (BNOCL) Barbados National Terminal Company Ltd. (BNTCL) Barbados Water Authority (BWA) BHP Billiton Repsol
Energy Distribution	Transmission, distribution, and retail sale of electricity, natural gas, and liquid fuels	Barbados Light and Power Company Limited (BLPC) National Petroleum Corporation (NPC) Private fuel retailers
Energy Consumption	Consumption of electricity, natural gas, and liquid fuels	Barbados Water Authority (BWA) Government Transport Private businesses Residential users

Source: [1]

2.3 Challenges in the current electricity sector and possible solutions

Based on documentation reviewed, and feedback from stakeholders, we have identified a list of challenges facing the energy sector in Barbados which can be split into groups of technical, regulatory, economic, socio-economic, and environmental.

A key narrative that emerges is that as the energy sector suffers from its dependence on imported oil which leads to high cost of energy and fiscal challenges which also concentrates the market around very few key players. For the future transition towards developing local renewable energy resources (RESs), a level playing field based on a transparent and fair industry with wider participation and skills development is seen as a key success factor.

Technical challenges mainly highlight the fact that Barbados will largely be dependent on intermittent RESs in the future. Environmentally, the competing uses for land as well as the impacts from large-scale renewable generation on the island landscape have been highlighted. Key challenges and potential solutions/mitigations are included in Appendix B.

2.4 Conclusions

Barbados' total primary energy consumption is around 15 Exajoules (EJ) (or 15,000 Terajoules [TJ] or 4,200 GWh) and this level of consumption is about the same level as the early 1990s.

Most of Barbados' energy is imported, although the country does produce crude oil, natural gas, and biomass. The share of energy produced indigenously as a proportion of total energy supply has fallen since 1990, from 34% to 15-17% in recent years.

Over the period 1990 to 2019, oil products have been the dominant energy type in Barbados. The reduction in bio-energy use reflects the decline in the sugar industry.

Oil is mainly used in transport (which accounts for almost half of final end use) and in power generation, which shares most of the remainder of fuel input with bunker or marine oil. Clearly, transport and electricity generation are two of the key target decarbonisation areas. Oil products are all imported, with Barbados exporting a small quantity of crude oil. Bioenergy, natural gas, and primary electricity (from solar) all play a minor role.

Over the last two decades, there has been a relative decline of energy use in manufacturing (industrial) and household (residential) demand while commerce (commercial) and transport demand have increased. Transport is currently the largest energy end user.

In order to diversify the energy mix and decarbonise the Barbados economy, there has been a growing interest in decentralised electricity generation in recent years. This has been encouraged under the Feed in Tariff (FiT) arrangement, including a scheme called the Renewable Energy Rider.

The GoB is now in the process of exploring new regulatory and market models for opening up the energy business, especially for electricity generation, storage, and independent supply.

Table 2.2: Challenges and solutions in the current electricity sector

No.	Challenge	Possible Solutions/Mitigations
1	**Technical/Reliability/Operational**	
1.1	Insufficient system reserve (e.g., two-day system blackout in 2019)	Fast-ramping thermal plant (biofuels if necessary), and energy storage, possibly Battery Energy Storage Systems (BESSs) as these can be commissioned in under a year
1.2	Maintaining (or increasing) energy supply reliability in a situation where a high share of future generation is asynchronous	Same as above but with synchronous condensers (SCOs) added
1.3	Diversification of generation technologies	Incentives and policy direction
1.4	Insufficient penetration of distributed generation and storage	Attractive distributed generation and storage tariffs, and smart systems for the TSO to make use of the distributed storage when required
1.5	Lack of synchronous electricity storage such as Hydro Pumped Storage (HPS) and Compressed Air Energy Storage (CAES)	Commission HPS and CAES feasibility studies specifically at geological and geotechnical issues
1.6	Lack of long-term storage (days, weeks, and months)	Commission hydrogen feasibility studies
1.4	Lack of sophisticated weather and RE forecasting system	TSO to implement a weather forecast system
1.5	Shortage of “smart” systems such as air-conditioner (A/C), and water heating controls for system stability reasons	Commission a smart system study
1.6	No smart EV charging/discharging systems for system stability reasons	Ensure that EV solutions come with smart systems linkable to the TSO
1.7	Required back-up of electricity systems for key functions as BWA desalination plants, hospitals, etc.	Commission a back-up power study. Options could include Internal Combustion Engines (ICES) running on biofuels or BESSs.
1.8	Insufficient system resilience due to:	
1.8.1	Lack of sub-system Islanding design with re-synchronisation capability of the sub-islands	Commission an islanding and islanding protection study
1.8.2	OHLs which are susceptible to extreme weather events	Replace OHLs with Underground Cables (UGCs).
1.8.3	Lack of operating reserve	As in 1.1 above.
2	**Land**	
2.1	Balancing competing uses for land given that renewable energy generation has a high land take	Commission an integrated town-planning, land-use, water, agriculture, and energy Geographic Information System (GIS) study
3	**Fiscal and forex outflows**	
3.1	Large outflow of forex for oil products in the power generating sector	Diversify to RE generation and BESS, and other energy storage technologies
4	**Environmental**	
4.1	Achieving high levels of decarbonisation in the energy system	Diversify to RE generation and BESS, and other energy storage technologies

No.	Challenge	Possible Solutions/Mitigations
4.2	Mitigating environmental and visual impacts of high levels of renewable generation	Use of low-grade agricultural land, use of non-categorised land, and good ESIA guidelines for RE projects
4.3	Mitigating the impact of the cruise liners on energy use and emissions	Use of RE to electrify cruise liners while in port
5	**Socio-economic challenges**	
5.1	Balancing the social-economic benefits, e.g., of supporting the sugar cane sector through using local biomass	Commission an indigenous bio-fuels industry study
5.2	Insufficient enfranchisement of citizens	Tariff and financial incentives for distributed generation and mechanisms for shareholding in utility scale projects
5.3	Insufficient education and marketing of the benefits of customer RE and storage	Improved marketing possibly and incorporation into school and university curricula
6	**Market/regulatory**	
6.1	Lack of market design, regulatory, and legal framework for a transparent and fair RE industry (leading to unsolicited RE bids)	Expedite activities in progress to formalise the RE IPP industry, and the unbundling of the vertically integrated industry
6.2	Access by the MESBE to sufficient network data and other data to create a “fair playing field”	MESBE to take on GIS staff, and improve data gathering and processing
7	**Capacity and Resources challenges**	
7.1	Capability of MESBE to undertake IRRP and transmission studies	MESBE to take on qualified and experienced staff to conduct generation and transmission expansion studies
7.2	Lack skill in large bioenergy, on-shore wind, and off-shore wind generation projects	Improve university and tertiary curricula, and temporary contracting of international experts or consultants
8	**Cost**	
8.1	The high costs of Barbados electricity are a result of fluctuating and high international oil prices	Diversification of generation, increased distributed generation, and energy storage
9	**Energy Diversity**	
9.1	From the Sankey diagrams presented above, it can be seen that Barbados is almost entirely dependent on imported fossil fuels for its energy requirements	Diversification of energy as described above

Source: Mott MacDonald

Asset Assessment

3 Asset Assessment

This section presents an assessment of current generation asset conditions and status against normal industry standards to inform the generation planning task. Asset age and performance are reviewed to inform possible life extensions and retirement decisions. This desktop review[2] assesses the asset data available in the PLEXOS model for Barbados obtained from Barbados Light and Power Company (BLPC).

3.1 Overview of current assets

Barbados' power assets are currently predominantly owned by BLPC. In addition, there is 30 MW of distributed solar PV connected to the MV and LV networks.

BLPC's generation assets are dominated by oil-fired plants on three sites – Spring Garden (the main site), Garrison, and Seawell. These oil plants comprise 2 x 20 MW steam turbine units (HFO fired); four 12.5 MW reciprocating internal combustion engines (RICE) (low speed diesels (LSDs) fuelled by HFO); 2 x 30 MW RICE LSD units (operating on HFO), and 6 gas turbines (which burn diesel and/or aviation fuel) including a 17.5 MW unit (GT01) which is just kept for emergency duty.

In addition to these oil plants, BLPC has a 10 MW ground-mounted PV installation at Trents and a battery energy system (5 MW/21 MWh). BLPC uses its battery assets to provide operating reserves (for frequency response), and to smooth and firm up intermittent solar PV output.

Table 3.1: Overview of current power generation assets in Barbados

Power Generation Asset	Year Installed	Retirement Date	Maximum Rating	Fuel Type	Fuel Efficiency
			MW gross		
Steam Station (Spring Garden)					
Unit S1	1976	12/31/23	20	HFO	21.5%
Unit S2	1976	12/31/23	20	HFO	21.5%
Sub-total			**40**		
Low Speed Diesels (Spring Garden)					
Unit D10	1982	12/31/28	12.5	HFO	35.6%
Unit D11	1982	12/31/28	12.5	HFO	35.6%
Unit D12	1987	12/31/28	12.5	HFO	35.6%
Unit D13	1990	12/31/28	12.5	HFO	35.6%
Unit CG01	1985, Upgraded 1993	12/31/28	1.5	Note 1	
Unit D14	2005	12/31/35	29.7	HFO	40.7%
Unit D15	2005	12/31/35	29.7	HFO	40.7%
Unit CG02	2005	12/31/35	2.2	Note 1	
Sub-total			**113.1**		

[2] Due to ongoing COVID travel restrictions and safety concerns, it has not been possible to carry out site inspections.

Power Generation Asset	Year Installed	Retirement Date	Maximum Rating	Fuel Type	Fuel Efficiency
Gas Turbine (Spring Garden)					
Unit GT01 (Note 3)	1973		17.5	Diesel	16.3%
Sub-total			**17.5**		
Gas Turbines (Garrison)					
Unit GT02	1990	12/31/23	13.0	Diesel	19.8%
Sub-total			**13.0**		
Gas Turbines (Seawell)					
Unit GT03	1996	12/31/26	13.0	Jet A1	24.3%
Unit GT04	1999	12/31/28	20.0	Jet A1	25.8%
Unit GT05	2001	12/31/30	20.0	Jet A1	25.8%
Unit GT06	2002	12/31/30	20.0	Jet A1	25.8%
Sub-total			**73.0**		
Solar PV (Trents)					
Trents Solar PV	2016	12/31/36	10.0		
Unit BESS01	4/30/18	12/31/28			
Total Installed Capacity - Existing and Committed			**249.1**		

Notes:

1. Uses heat recovered from LSD exhaust gases and therefore requires no fuel.
2. HFO = Heavy Fuel Oil (or fuel oil #6)
3. GT01 available for emergency use only, and not included in total capacity

3.2 Asset Assessment and Benchmarking

3.2.1 Introduction

This section presents a detailed review of the plant information available. We first present a benchmarking exercise of asset age for which sufficiently large amounts of information are publicly available. For a more detailed look at the assets, we address them by technology in turn. The assessment of the asset status is based on our available in-house asset information and relevant specialist experience as information in the public domain about relative industry standards is otherwise scarcely available.

3.2.2 Benchmarking of Asset Age

This section compares the Barbados power plant age data from Table 3.1 above with comparable island energy systems sourced from GlobalData[3]. The attributes analysed are current and decommissioning age, active capacity (MW), and fuel type. Fuel type describes the category that the plants' primary fuel falls under.

It should be noted that current age ('age') is not equivalent to lifespan; there is relatively incomplete data for age of decommissioned plants at their date of decommissioning and so the charts with current age as a metric serve only as indications of how the current ages of

[3] GlobalData is one of the best-known market research publishers worldwide today which provides subscription-based access to a wide range of detailed industry information (https://www.globaldata.com/)

Barbados power plants sit amongst those of similar island systems presently in use. Also note that this data contains future power plant commissions.

The Barbados power plant data includes Unit GT01; a gas turbine station in Spring Garden running on fuel oil. It is 47 years old and the oldest active power plant in the Barbados network. It is important to note that this is available for emergency use only and therefore is only maintained for occasional use, resulting in an unusually high current age. Note that this data does not contain plant maintenance history, which will have an influence on lifespan.

Units CG01 and CG02 are excluded from this analysis since they use recovered heat and require no fuel, and form part of the Spring Garden power station's Low Speed Diesel Units.

3.2.2.1 Distribution of power plant active capacity

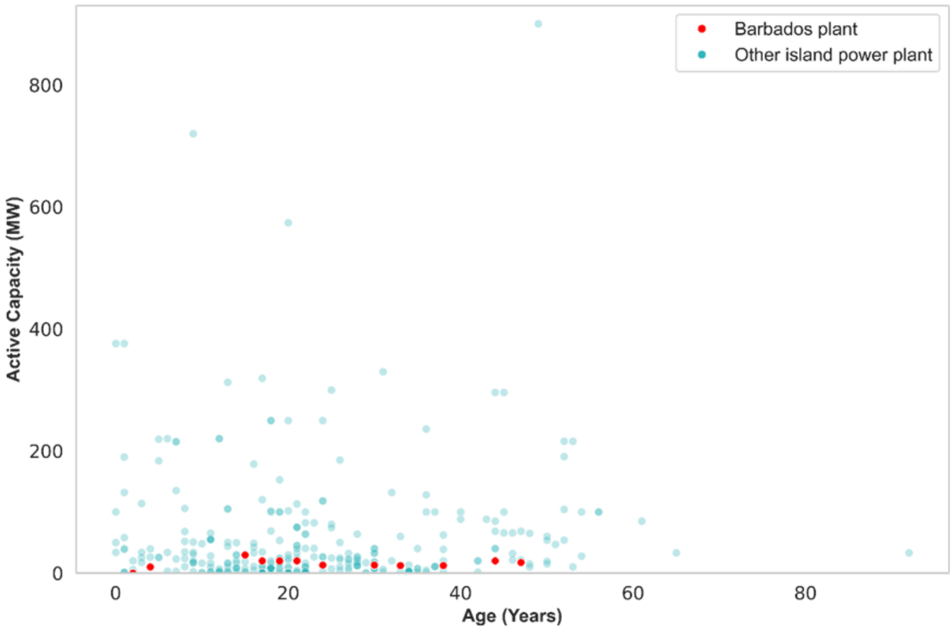
Figure 3.1 shows the age of various island system power plants (blue) and Barbados plants (red) against their active capacity (MW). It highlights the available and selected benchmarking data we have obtained which were based on similar system characteristics (small island systems with a particular focus on Caribbean and Pacific Island systems).

The data shows that most of the island system power plants, and all of the Barbados plants, have a capacity of less than 100 MW, which is what would be expected and therefore validates the data selection process for this benchmarking exercise.

Notable is also that very few power plants are older than 50 years.

The assets in Barbados fall inside the range of the age distribution and the bulk of the assets are clustered around the average asset age found elsewhere.

Figure 3.1: Active capacity of island system power plants against current age

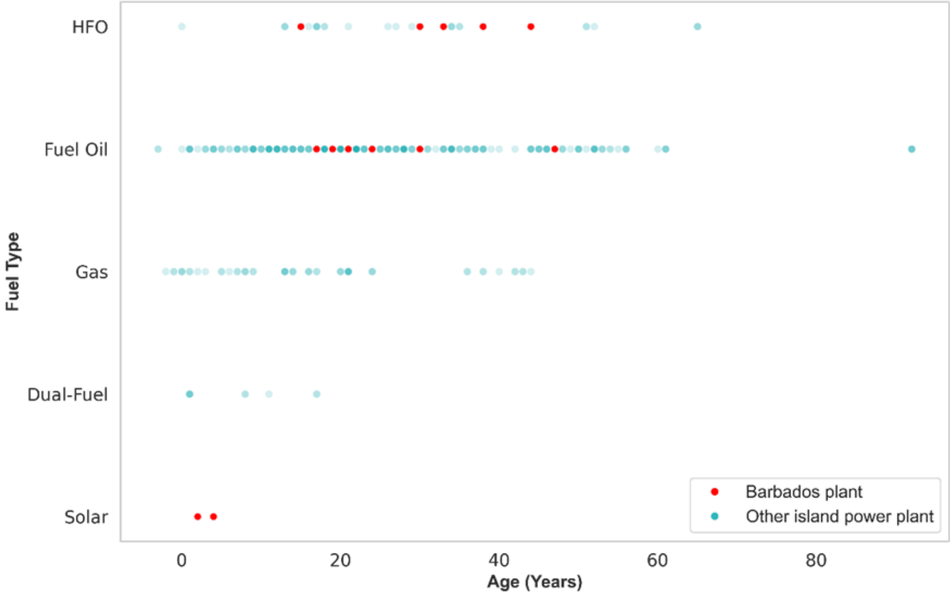


Source: Mott MacDonald with information from Barbados Plexos Model and GlobalData

3.2.2.2 Distributions of power plant current age by primary fuel type

Figure 3.2 shows the current ages of power plants, both in Barbados (red) and other island systems (blue), against their respective fuel category.

Figure 3.2: Current age of island system power plants by fuel type



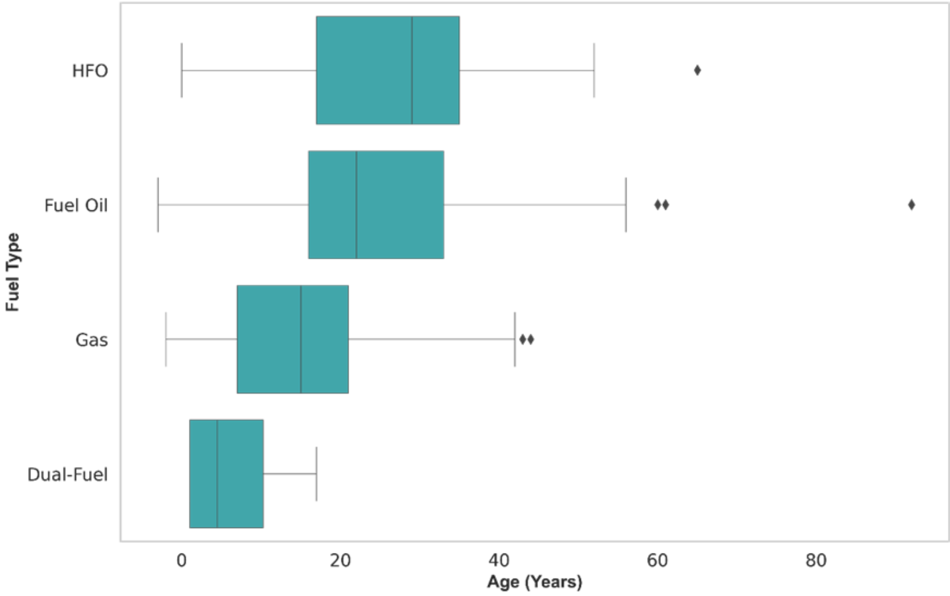
Source: Mott MacDonald with information from Barbados Plexos Model and GlobalData

Fuel oil (which includes distillates such as diesel and jet fuel) is the category with the greatest number of corresponding power plants. It is also the fuel type for which power plants have the greatest range of current age. This is indicative of more diverse use cases in the mid-merit to peaking plant range where a longer useful lifespan would usually be attributable to fewer running hours for such peaking plant (relative to baseload plant which would operate on Heavy-Fuel Oil (HFO)).

The exceptionally old power plant is Queens Park Power Plant in Grenada in the Caribbean: it is 92 years old according to the available records. However, it was last upgraded in 2015 and may have frequently been life-extended throughout its operational period, which could explain such an unusually long asset life.

Figure 3.3 demonstrates the spread of the age data within each fuel category corresponding to power plants from other island systems.

Figure 3.3: Spread of power plant current age by fuel type (excluding Barbados plants)



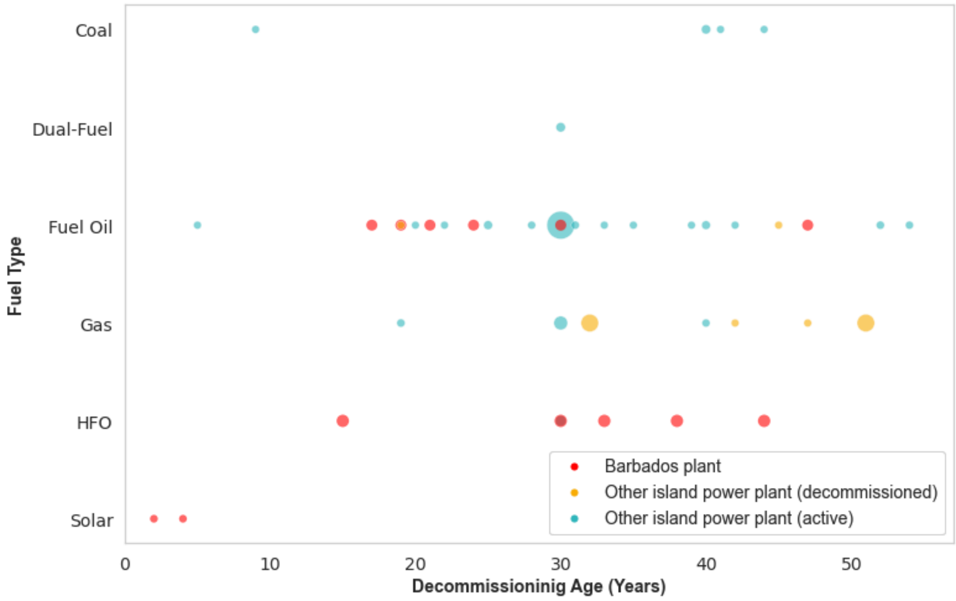
Source: Mott MacDonald with information from GlobalData

HFO power plants are on average the oldest type of power plant in the data, however there are more instances of especially old fuel oil power plants. Referring to Figure 3.2, the ages of the Barbados fuel oil plants seem to be clustered about the average age. This would indicate these plants still have another one or two decades of use left.

3.2.2.3 Decommissioning age and Barbados plants' current age

Figure 3.4 shows the decommissioned age of already decommissioned plants (yellow), the suggested decommission age of active plants (blue), and active Barbados plants (red), all of which are split by primary fuel type. The size of the points indicates how many plants will be or have been decommissioned at that age.

Figure 3.4: Spread of decommissioning age (of active and decommissioned plants) and current age of active Barbados plants, by fuel type [# of plants represented by pointer size]



Source: Mott MacDonald with information from Barbados Plexos Model and GlobalData

The data suggests that many active plants intend to be decommissioned at around 30 years of age. The HFO plants are entirely planned to decommission after 30 years of service; six of the total eight Barbados HFO plants are currently 30 years of age or older.

The decommissioning ages for fuel oil plants are often 30 years old; however, are often expected to operate for another decade or so. The fuel oil plants in Barbados are generally young, and many may have another decade or so of service, however the HFO plants in Barbados almost entirely exceed the typical 30-year lifespan. This may represent the heavy use of HFO plants which typically operate as baseload but could also have other reasons, such as economic trends that led to the adoption of higher efficiency plant while older steam turbine technology was phased out; the information is not contained within the dataset.

3.2.3 Detailed Asset Assessment

Detailed analysis of the BLPC power plants, plant technology and findings of the assessment can be found in Appendix C. The detailed analysis discusses the following power plants:

- Steam Turbines
- Reciprocating Internal Combustion Engines (RICEs)
- Cogeneration plants
- Aeroderivative Gas Turbines (GTs)
- Battery Energy Storage System (BESS)
- Solar PV plant (PV)

3.3 Conclusion

We can conclude from the asset age benchmarking exercise that the average expected asset life for internal combustion engines (ICE) and GTs used in Barbados would be 30 years. Steam plant (such as unit S1 and S2) could be expected to operate successfully for up to 50 years (assuming recommended overhauls are carried out). The practical evidence from operational plant in similar island systems that exceed their expected life also points to the feasibility of life-extensions for such assets. However, these decisions always require the context and intended application to be considered, while the most important drivers to retire or life-extend are the plant economics and reliability.

Unit S1 and S2 are 44 years old and, based on age alone, would be expected to retire within the next six years. However, these units show very low reliability and are expensive to operate at this point while their technical capabilities are not in line with the requirements for increasing renewable penetration. The recommendation would be to retire these units as soon as possible.

The ICE units (D11-D15) range in age between 15 and 38 years. These units are less reliable than would be expected while their efficiency is in line with expectations. It would be expected that all of these units, but certainly the younger ones, could still provide one or two decades of reliable service. Noting that it is generally possible to convert such units to be fired with liquid biofuels, this has been considered as an option in the generation planning study. However, such a conversion may introduce risks to the waste-heat recovery units that are attached to these units, which may need to be taken out of service at that point. It is recommended that these different options are studied further in terms of technical feasibility and their respective economic impact if this option is deemed attractive.

The GTs at Seawell power station are between 18 and 24 years old, and the GTs at Garrison and Spring Garden are 30 and 47 years old, respectively. Although with a typical design life of 25-30 years the Seawall units have another 6-12 years of life remaining, the Garrison units demonstrate that they can be kept in service for much longer. These units are not suitable for continued operation but ideal for back-up and emergency generation. Unfortunately, these units cannot be converted to renewable fuels It is recommended that the option is retained to consider these units specifically for back-up use in the generation planning study.

Demand Forecast

4 Demand Forecast

This section presents the review, update and recommendations for the methodology and assumptions of the MESBE demand forecast model. Three future scenarios have been defined to provide a comprehensive view of the demand evolution in Barbados. The demand forecast results for the three scenarios presented in this section includes forecasts from the MESBE Long Range Integrated Development Analysis (LINDA) model, newly electrified sectors (electric vehicles, cruise liners, cooking), and energy savings from Demand Side Management (DSM)/ Energy Efficiency (EE).

4.1 Methodology

4.1.1 Review of existing model

After discussions with MESBE we have agreed to use the ministry's own LINDA demand forecast model. The LINDA model builds up demand sector by sector. The LINDA model forecasts energy demand in Barbados' commercial, hotels and restaurants, industry, residential, and transportation sectors. Electricity demand in the LINDA model is forecasted in all the sectors, with future Electric Vehicles (EVs) and Cruise Liners (CLs) electricity demand considered as individual sectors in the updated LINDA model.

Demand in three sectors: industry, commercial, and hotel and restaurants, accounts for about 65% of the current demand and is assumed to be linked to the economic growth in each sector via an electricity intensity factor which can be adjusted by the forecaster. Residential demand forecast is based on an estimated annual growth rate (which is loosely based on historic energy consumption growth in the sector), with no endogenous correlation to economic activity or demand in other sectors.

The MESBE has forecasted the growth rates of real Gross Domestic Product (GDP) and electricity intensity in the three economically driven sectors, for three scenarios: Reference, Low, and High scenarios. The forecast was carried out using Autoregressive Integrated Moving Average (ARIMA) intervention analysis on real GDP and electricity demand. The MESBE forecast has a pessimistic outlook for GDP in the short and medium term, with the Reference scenario based on the following key assumptions [57]:

- High and lingering unemployment locally and in the international economy;
- Continued and long-term reduction in international travel;
- Weak tourism performance;
- Stressed and anaemic economic performance locally;
- COVID-19 virus impacting the world economy from 2020 – 2022;
- Increased use of Renewable Energy (RE) technology and reduced use of fossil fuel.

The overall growth in aggregate real GDP in the MESBE's Reference scenario averages 0.8%p.a. between 2021 and 2025, and 0.7%p.a. between 2026 and 2030 (Table D. in Appendix D). The commercial sector is projected to grow the fastest, followed by the hotel and restaurants, with the industry sector forecasted to have the lowest growth rate by 2040.

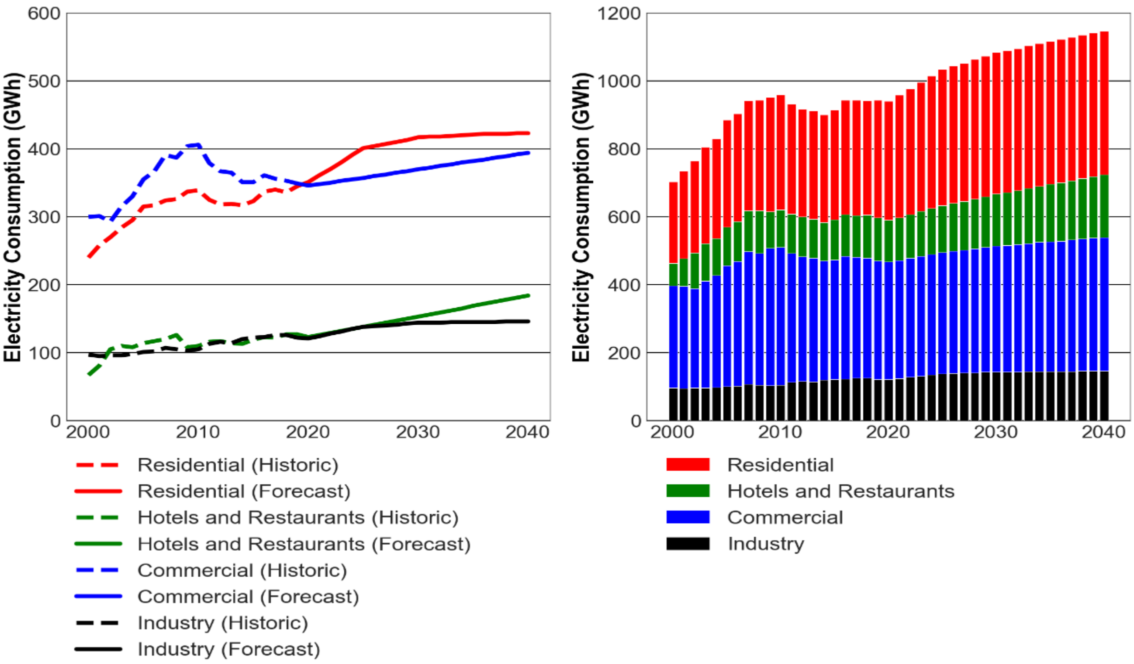
In the Reference scenario, the electricity intensity in the industry and hotel and restaurants sectors are projected to see a 2.2%p.a. and 1.8%p.a. increase respectively between 2021 and 2025, while the commercial sector sees a 0.3%p.a. decrease (Table D. in Appendix D). Meanwhile, the electricity demand in the residential sector is forecasted to see a significant growth of 2.7%p.a. between 2021 and 2025, and then experience a low positive growth in demand up to 2040.

Figure 4.1shows the MESBE's forecasted electricity demand by sector in the Reference scenario up to 2040. This clearly shows the importance of the residential sector and its expanding role in comparison to the commercial and hotels and restaurants sectors. The industry sector's demand is seen to have a low growth, especially between 2030 and 2040. Overall electricity demand in the Reference scenario is projected to increase from 944 GWh in 2019, to 1084 GWh in 2030, and 1147 GWh in 2040.

The forecasted electricity demand in the three scenarios in selected years is presented in Table 4.1. The demand outlook shows demand in the Reference and High scenarios rising to 13% and 32% respectively by 2030, while the demand in the Low scenario declines to 9%. The annual forecasted electricity demand for each sector up to 2040 are presented in Table D.3 in Appendix D.

It is important to note that these demand figures do not include the potential demand from newly electrified sectors such as EVs, CL and cooking. In addition, we understand the scenarios do not include the potential impact of EE/DSM programmes which can be seen as a negative adjustment to the forecasted demand.

Figure 4.1: Historical and MESBE's forecasted electricity demand in the Reference scenario



Source: Mott MacDonald

Table 4.1: Forecasted electricity demand (GWh) in the Reference, High and Low scenarios

Demand	2021	2025	2030	2035	2040
Reference	959	1034	1084	1117	1147
High	988	1203	1300	1367	1424
Low	921	844	837	835	832

Source: MESBE- LINDA energy demand model

4.1.2 Electrification of new sectors

Following discussions and agreement with MESBE, we have made significant updates to the LINDA model in order to provide a more comprehensive view of the future demand evolution. We discuss each of the additional updates to the LINDA model in the sections below.

4.1.2.1 Electric vehicles (EVs)

The small size of Barbados makes the island a favourable place to roll out EV. The Government of Barbados (GoB) is keen to encourage EV uptake and has already approved the deployment of a number of charging stations. We have made a simple bottom-up estimate of potential EV demand for road vehicles, based on a number of assumptions regarding their deployment and use. Our key assumptions are outlined below.

Our starting assumptions are total fleet size of three key vehicle segments: light, medium, and heavy-duty vehicles (LDV, MDV, and HDV), and their respective annual electricity use. LDVs comprise predominantly of private cars, while HDV comprises trucks and buses, with MDV comprising vans, small trucks, and minivans. The fleet numbers are taken from GoB estimates, while the energy use is based on typical values seen elsewhere, adjusted for Barbados conditions.

Table 4.2 shows the average energy use and projected fleet size of EVs in a High case scenario. The key features to note are that the fleet sizes fall as one moves to heavier vehicles, while average consumption per vehicle increases, such that an HDV uses 16 times the energy of an LDV. Note that these figures are for the electricity supplied to a battery electric vehicle. The figures in Table 4.2 show a high potential uptake and it would take some time to build up to these levels, as new vehicles need to be brought into service since there is no practical case for vehicle conversions.

Table 4.2: Average energy use by EV and projected fleet in an Aggressive Case Scenario

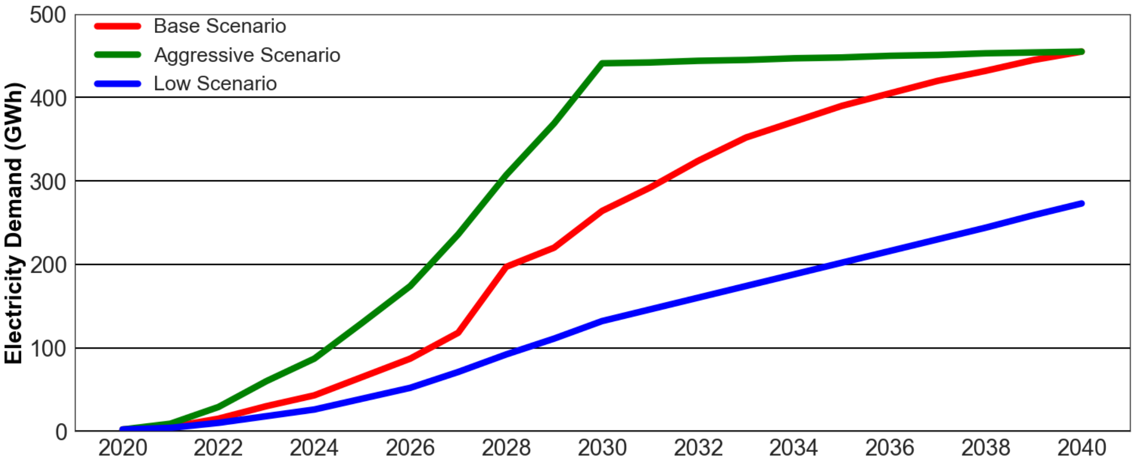
Type of EV	Total fleet no. in 2030	Annual electricity use by vehicle (MWh)	Potential electricity use in 2030 (GWh)
LDV	123,500	2.5	308.8
MDV	10,000	10	100
HDV	800	40	32

Source: Mott MacDonald estimates

Table D.4 in Appendix D shows our projected penetration of EVs for three growth cases (Base, Aggressive, and Low), with EV penetration reaching 60% in 2030 in our Base case, and 30% and 100% in our Low and Aggressive cases respectively. For simplicity we assume that all vehicle segments would have the same penetration rate, although one might expect a faster penetration rate for the HDVs and MDVs as these tend to have higher utilisation and are owned by fleet operators and so are often targeted first by policy makers.

Applying these penetration rates in the three scenarios leads to the projected EV demands shown in Figure 4.2. The total annual potential consumption in the Base and Aggressive scenarios comes to 455 GWh by 2040, which is a little less than half the current annual electricity use across all sectors. The figure compares with 1,500 GWh of gasoline and diesel used currently in road transport. This shows the potential EV consumption is reasonable given that an EV is typically 3-4 times as efficient as the comparable internal combustion engine vehicle.

Figure 4.2: Projected EV electricity demand

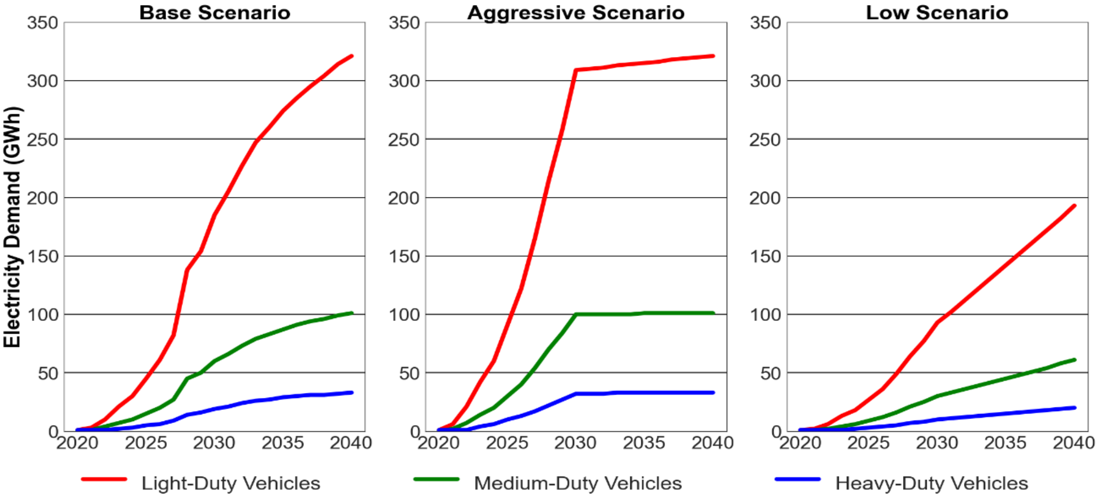


Source: Mott MacDonald

EV electricity demand in 2030 could be between 132 GWh and 440 GWh, with a central projection of 265 GWh in the Base scenario (Figure 4.2). Given that projected demand in the 2030 Reference scenario is 1084 GWh, this represents a very sizeable additional demand. The projected EV electricity demand for each type of vehicle in the three scenarios is presented in Figure 4.3, with the LDVs having significantly higher demand than MDVs and HDVs in all the scenarios. The annual forecasted EV demand for the different type of vehicles, in each of the three scenarios, are presented in Table D.5 in Appendix D.

In this study, we have assumed a 50/50% smart-charging/profiled-charging regime for the Base and Low EV scenarios. Profiled charging is where users adopt a fixed charging time which is easy or convenient and does not consider the electricity market or grid congestion conditions. Under an Aggressive EV scenario we anticipate that profile charging will be discouraged by discriminatory pricing or by charge point access such that users will charge when the power is most available, and the network is not seriously congested. We call this charging regime “smart" as it takes account of the wider system impacts and will charge the EVs on a least cost basis.

Figure 4.3: Projected EV electricity demand by vehicle type



Source: Mott MacDonald

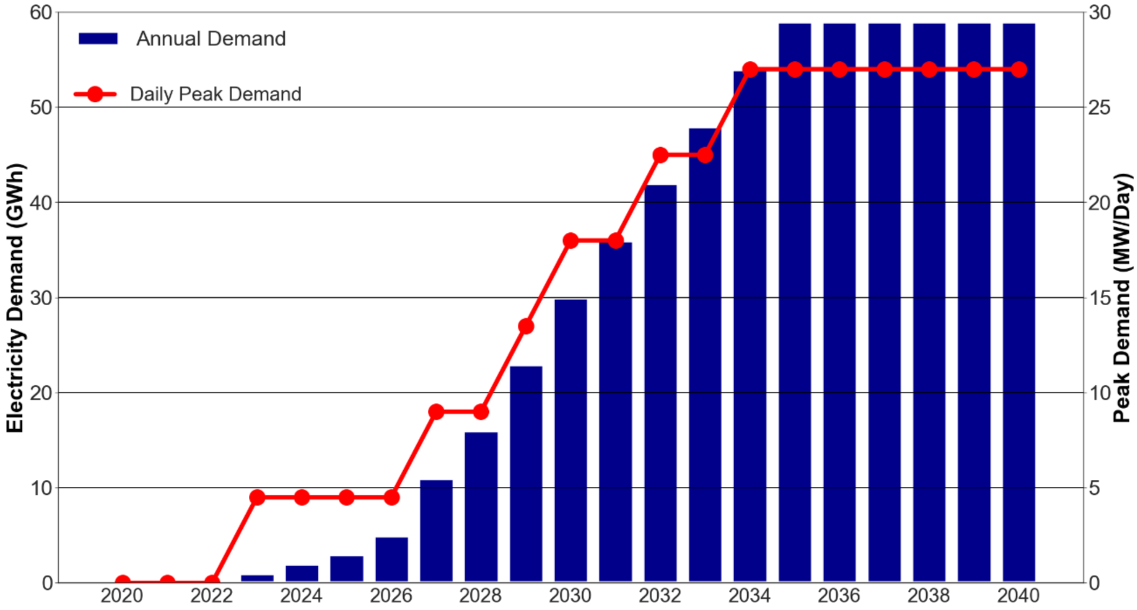
BLPC has supported deployment of charge-points for EVs and has started replacing its own fleet vehicles with EVs and hybrids [40]. BLPC installs EV chargers at its locations for charging of its fleet vehicles. These are not available to the public. The public chargers on the island are installed by MegaPower. The information on non-BLPC fleet chargers on island are available via a website. This is through the app called Plugshare [52]. As per Figure D.1 in Appendix D, MegaPower has 40 EV charging locations in Barbados. MegaPower predominantly uses 7 kW chargers although it has recently installed a 22 kW charging unit. MegaPower also has three 50 kW units and 80 kW charging units for 35 EV buses at Mangrove, Bridgetown, and Speightstown depots.

4.1.2.2 Cruise liners (CLs)

Generally, when CLs are in port, they run their own diesel generators for shore power supply. This load amounts to about 4.5 MW for a modern liner. In principle this could be replaced by drawing electricity from the grid. This would not be a continuous load as the liners tend to stay in port only during the day, so assuming they are in port 12 hours a day, a single liner in port would need 9.86 GWh/year over the six-month cruise season. This means that six liners would use just over 59 GWh a year.

In the Base case we assume 50% of the vessels are converted by 2030, so accordingly the consumption is just under 30 GWh in that year – see Figure 4.4. The detailed build-up of the CL electricity demand is presented in Table D.6. Even if 100% of shore power is supplied by grid electricity in 2030 (High Case), this is still a comparatively small demand in terms of annual energy use (6% of the Reference scenario). However, in terms of demand on the system, this 100% full conversion in the High case would represent 27 MW of additional day time demand during the cruise season. Table D.7 in Appendix D shows the forecasted annual demand and hourly profiles for CL in the Base, High, and Low cases.

Figure 4.4: Projected Cruise-liners electricity demand in the Base case



Source: Mott MacDonald

4.1.2.3 Cooking

According to the 2019 energy balance, approximately 103 GWh of LPG and 137 GWh of natural gas was used in the commercial and residential sectors. We do not know exactly how these sectors are defined or what these fuels are used for. However, it is known that a large amount of this energy is used for cooking, so it is worth making a broad estimate of what could be switched to electricity. Assuming cooking is half of this total use then this would require substituting 120 GWh a year. However, given that electric stoves are one and half to twice as efficient as the gas appliances this would represent an additional electricity demand of 60-70 GWh, based on the 2019 consumption. This would be a 6-7% uplift on electricity demand.

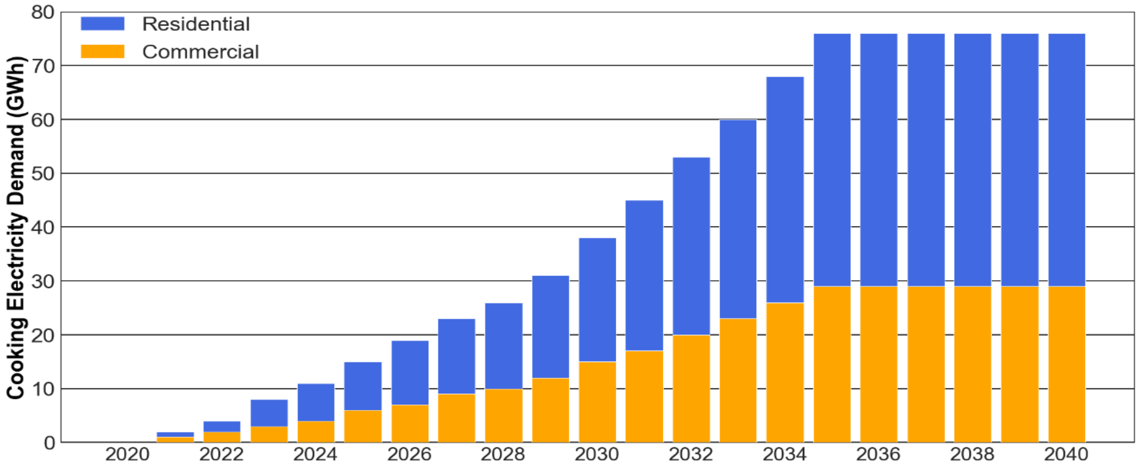
This demand would likely be phased in gradually as users buy new appliances rather than being the result of large facilities switching over, as such this additional demand would be phased in over a decade or more. Figure 4.5 shows one possible scenario for the build-up of this electricity demand used for cooking. A detailed breakdown of the potential electricity demand for cooking in the commercial and residential sectors in Base, High, and Low cases is presented in Table D.8.

4.1.2.4 Demand Side Management

MESBE's electricity demand projection does not factor in any major DSM initiatives beyond the underlying EE improvements, which are captured in the historical trend for energy intensity. The 2015 study by DNV-GL [12] on DSM identified significant energy saving potential for Barbados. DSM here refers to EE savings and demand side management (reductions in peak load), the latter often being called demand side response (DSR). DNV-GL estimate that the technical potential of EE by 2025 would be 371 GWh a year, which is about 40% of the final demand.

However, achievable savings, assuming a strong incentive programme were applied could be about 210 GWh, or about 22% of final demand. Most of these savings (145 GWh) would come from the non-residential sector, especially offices, hotels, and retail, with about 60 GWh from the residential sector. Note, these are the annual savings for 2030 and there is the expectation that additional savings could be made in the longer term as shown in Table D.9.

Figure 4.5: Potential cooking demand in the commercial and residential sectors



Source: Mott MacDonald

According to DNV-GL [12], in the non-residential sector the main potential EE savings areas are lighting (which in 2014 accounted for 40% of electricity use), cooking (21%) and office equipment (11.5%). Refrigeration, motors, and cooking/vending were other significant uses. In contrast, the residential sector's use was dominated by refrigeration, with 45% of use, with televisions and personal computers accounting for almost 24%. Lighting by comparison was only 8%.

According to the study, savings for peak demand (DSM proper) appear significantly less marked than for energy, with economic potential of 35 MW by 2030, with the achievable savings less than 30 MW. Key target areas of controllable demand are large chillers, pool pumps, and waste-water treatment processes, although the introduction of special tariffs would be expected to move load in other areas too. For the most part DNV-GL advocated using incentive mechanisms, rather than strong compliance regulations which prohibit purchase or use of less efficient equipment. That said DNV-GL did not recommend tightening standards on new appliance however this is something which the BNEP 2019-2030 has included for instance on lighting, air conditioners, and refrigeration as well as other domestic kitchen appliances.

The potential DSM savings (GWh/year) and peak demand savings (MW) in three scenarios (Base, Aggressive, and Low) up to 2040 are presented in Table D.9. The DSM savings are projected to be 139 GWh in 2030 in the Base case, and 277 GWh and 69 GWh in the Aggressive and Low cases respectively. On the other hand, peak demand savings is projected to be 17 MW, 34 MW, and 8.5 MW in the Base, Aggressive, and Low Cases respectively by 2030.

4.2 Assumptions

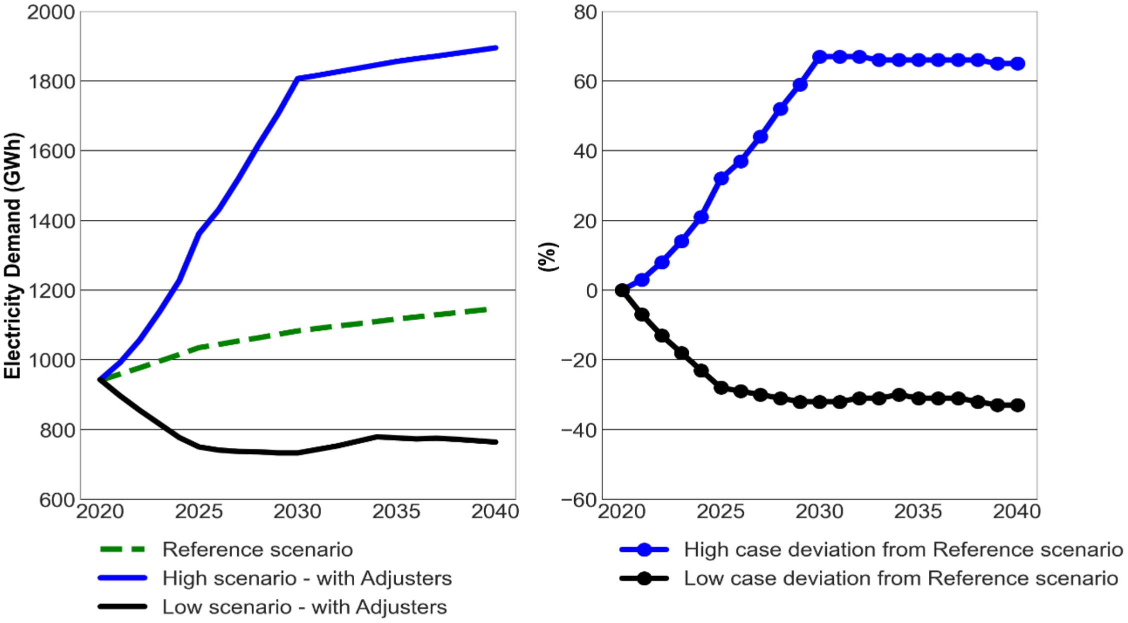
4.2.1 Scenarios

As outlined in Section 4.1.2 the demand forecasts are built up from an underlying demand projection using the LINDA model and then adjusting for demand from new sectors (EV, CL, and cooking) and a negative adjustment for impacts of EE programmes. Given the expectation of low economic growth rates and a low rate of change in energy intensity, the differences in the underlying demand projections in 2030 between the High and Reference scenario is at 17%, However, this difference increases to 19% by 2040.

A much greater range of outcomes is produced once we include a reasonable range of impacts from additional sectors and EE adjustments. If we combine High economic growth with High EV uptake, Low DSM, High CL, and High cooking, then this adds about 32% to the Reference underlying demand in 2025 and 67% in 2030 – see Figure 4.6. On the other hand, combining the Low economic growth case with the Low EV, High DSM, Low CL, and Low cooking, leads to a total demand level 28% and 31% below the underlying Reference scenario in 2025 and 2030 respectively.

In Figure 4.6 the High and Low scenario deviations from the underlying Reference case is wide at 66% and -33% respectively, and so we propose adopting fewer extreme scenarios. Three realistic scenarios are outlined in Table 4.3, alongside the underlying Reference, High and Low scenarios of the LINDA model. The range of underlying demand uncertainty is moderate, however there is considerable uncertainty relating to the new sector demand and EE programmes. The proposed scenario combinations have been agreed with MESBE.

Figure 4.6: Potential range of demand scenarios (extreme cases)



Source: Mott MacDonald estimates

Table 4.3: Explanation of Demand Forecast Scenarios

Demand scenario	Components of the demand scenario
Base	**Underlying Reference demand scenario provided by MESBE in the LINDA model, combined with the following adjustments:**
	Addition of base EV projection – which has 60% EV market share by 2030, with 50% smart charging and 50% fixed profile charging
	Addition of base CL demand – six ships – 50% conversion by 2030
	Additions of base cooking demand
	Deduction of base case DSM/EE savings.
High	**Underlying High demand scenario provided by MESBE in the LINDA model, combined with the following adjustments:**
	Addition of high (aggressive) case projection of EV demand - 100% EV share in 2030, with 100% smart charging

Demand scenario	Components of the demand scenario
	Addition of base CL demand – six ships – 50% conversion by 2030 Additions of base cooking demand Deduction of base case DSM/EE savings.
Low	**Underlying Low demand scenario provided by MESBE in the LINDA model, combined with the following adjustments:**
	Addition of low case projection of EV demand - 30% EV share in 2030, with 50% smart charging and 50% fixed profile charging
	Addition of base CL demand – six ships – 50% conversion by 2030
	Additions of base cooking demand
	Deduction of base case DSM/EE savings.

Source: Mott MacDonald

4.2.2 Load Profiles

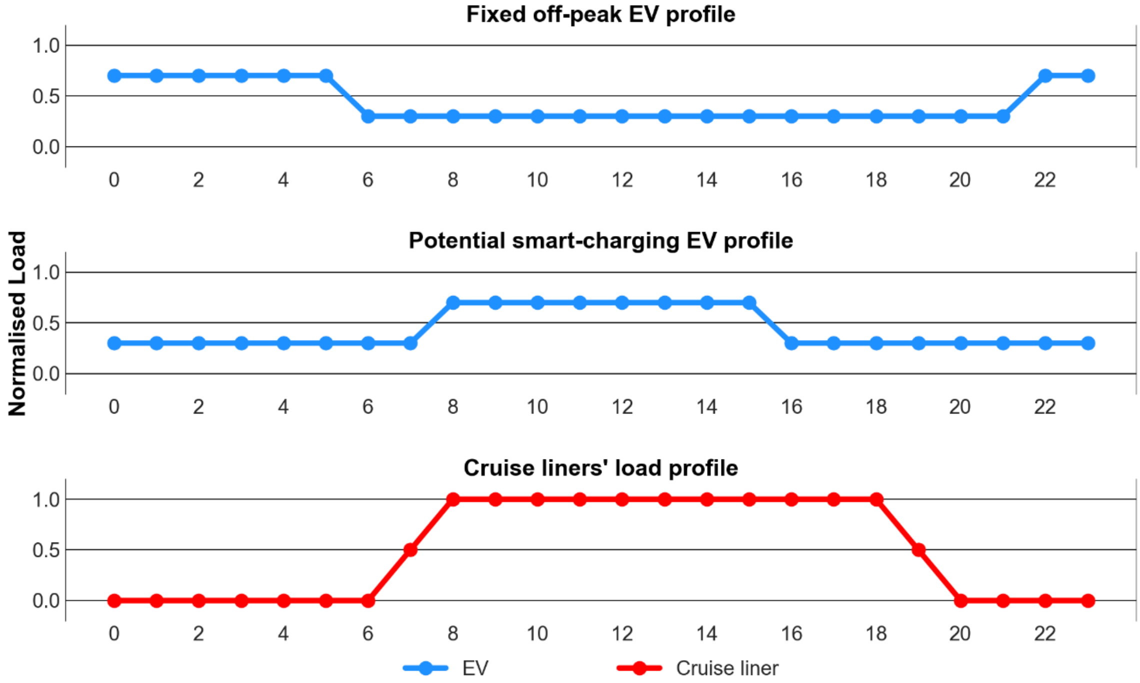
Forecasted load curves typically have the same shape over a number of years, as past hourly electricity demand is scaled to any increase or decrease in annual demand. However, significant changes in demand consumption patterns will have an impact on future load curves. The plans by the GoB to encourage the gradual integration of EV, and also supply CL electricity from the grid when in port could potentially have an impact on the annual load curve.

As mentioned in Section 4.1.2.1, we are assuming 50/50% smart-charging/fixed profiled-charging in the Base and Low EV scenarios, and 100% smart charging for the High EV scenario. For the 50% fixed profiled charging, if we assume two-third of fixed-chargers take advantage of the comparatively lower energy price at night and charge their EV from 10pm till 6am. The resulting normalised load profile for fixed charging is shown in Figure 4.7

Assuming the smart EV chargers communicate and respond to system price and stability signals, the EV fleet that is connected to charging points can be dispatched to charge at optimal times (e.g., when there is a surplus of power, typically during sunshine hours). Under such a regime, charging can also be interrupted to provide the system flexibility to balance intermittency of power supply (e.g., during passing clouds affecting the output of solar PV). Therefore, the smart portion of the EV can provide a contribution to reserve and ancillary services in the form of DSR. Figure 4.7 illustrates a potential smart charging load profile, assuming eight hours of uninterrupted solar PV generation.

For the electrified CL during the peak six-months cruise season (December to May), we assume they arrive at the port from 7am and then connect to the grid for electricity supply. As arrival times will differ for the different liners, we assume only 50% of the liners will be connected in the first hour, and then 100% connected to the grid by 8am. Similarly, the same load pattern is expected at departure time, which will start from 7pm. Figure 4.7 shows the normalised load profile for electrified CLs in a typical day.

Figure 4.7: Assumed normalised daily load profile of Cruise liners and Electric Vehicles



Source: Mott MacDonald

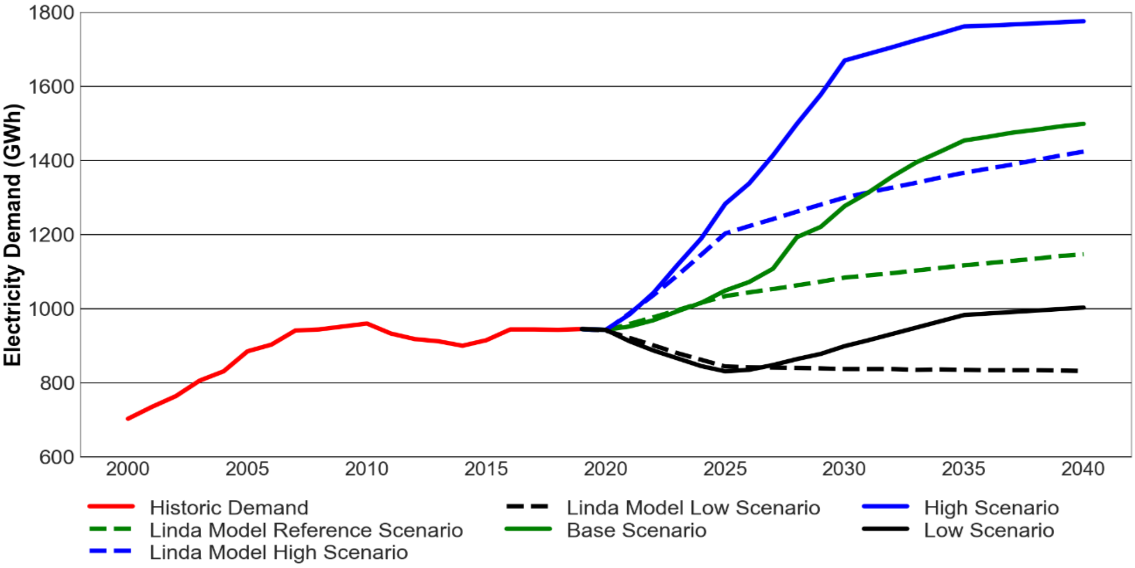
4.3 Results

The projected annual demand for the three defined scenarios (Base, High, Low) up to 2040, are presented in Figure 4.8 and Table D.10. The Base scenario demand initially rises slowly to reach 1049 GWh in 2025 and then more rapidly to reach 1277 GWh in 2030 and almost 1500 GWh by 2040. The High scenario sees demand growth accelerating through 2020s to reach 1670 GWh in 2030, before growth decelerates in the 2030s to reach 1776 GWh in 2040. The Low scenario sees demand falling slightly before slowly recovering from 2025 onwards to reach 899 GWh in 2030 and 1003 GWh in 2040. The spread between the projections is significant with the High and the Low scenarios standing at 31% above and 30% below the Base scenario in 2030, while in 2040 the corresponding figures are +18% and -33%.

These demand forecasts relate to final electricity demand and as such we need to add losses in the transmission and distribution network to get the final generation requirements figure needed for the generation planning analysis. Using the loss rate implicit in the Barbados energy balances for 2019 we need to scale the final electricity consumption by 7.2% to give the net generation requirements. Note that this loss adjustment is equivalent to a loss rate of 6.7% as normally reported by utilities (where losses are expressed as a percentage of sent out energy). Table D.10 shows the projected generation requirements for the three scenarios using the losses adjuster. This shows generation requirements in 2030 ranging between 963 GWh and 1791 GWh with 1368 GWh as the Base scenario. In 2040, the corresponding spread is 1075 GWh to 1904 GWh, with 1607 GWh for the Base scenario.

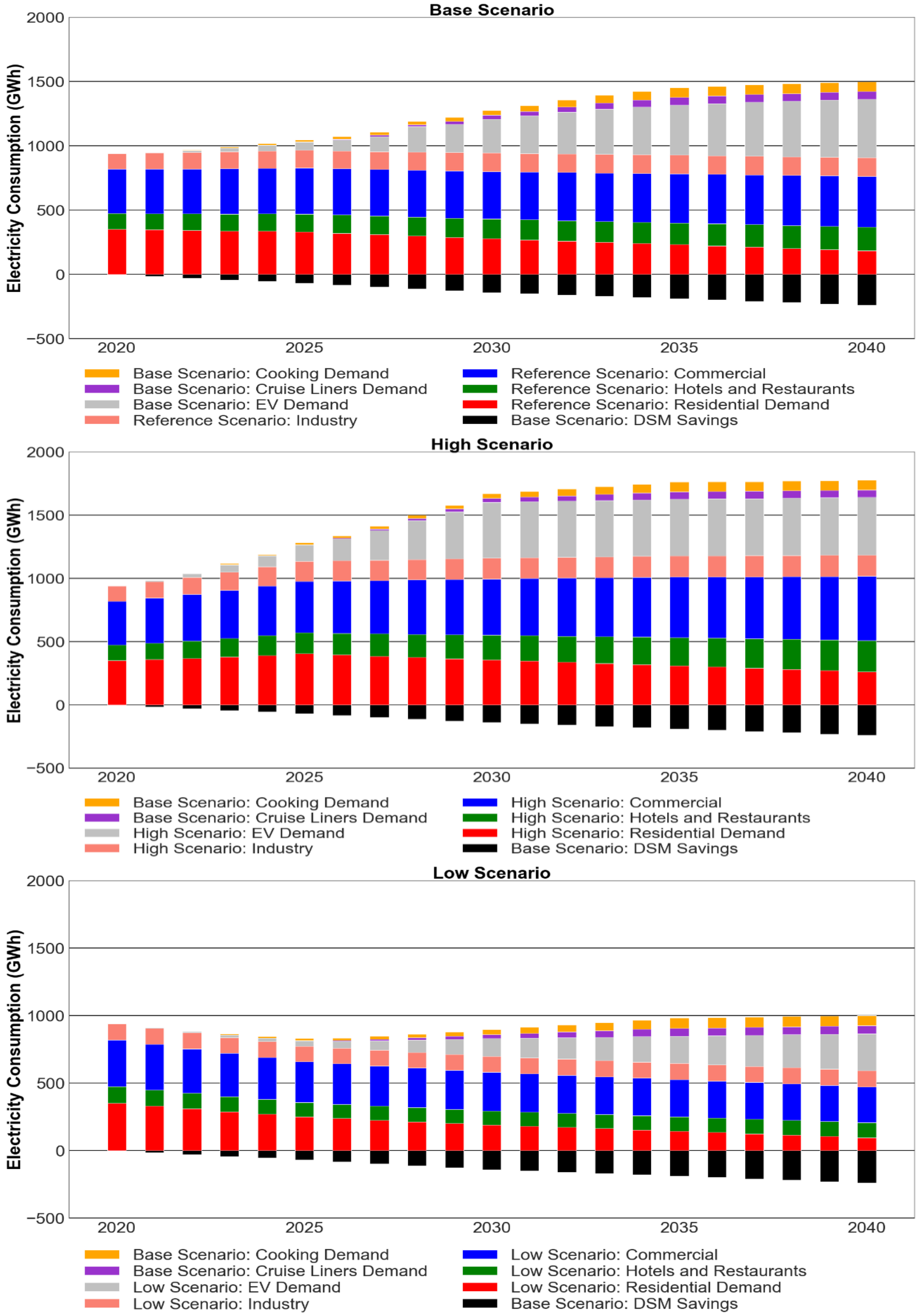
Figure 4.8 shows the three scenarios alongside the historical demand and the underlying demand scenarios from the LINDA model, with the detailed data presented in Table D.11. By 2030, it is projected that the Base, High, and Low scenarios will deviate from the underlying Reference scenario by 18%, 55%, and -17% respectively. The deviation of the High scenario from the underlying Reference demand remains at 55% by 2040, while the Base scenario rises to 31% and the Low scenario decreases to -13%. Figure 4.9 shows the demand projections in the three scenarios by sectors and highlights the impact of the three scenarios of the underlying demand and EV demand, particularly from 2030 onwards (see Table D.12,Table D.13, and Table D.14). Overall, electricity demand in the Base scenario is forecasted to increase from its 2019 levels by 35% and 59% in 2030 and 2040 respectively.

Figure 4.8: Final electricity demand under Base, High, and Low scenarios in the underlying LINDA model and updated model.



Source: Mott MacDonald

Figure 4.9: Projected electricity demand in the Base, High, and Low scenarios by sector



Source: Mott MacDonald

4.4 Conclusions

The LINDA model is an Excel-based modelling tool that forecasts electricity demand in Barbados' commercial, hotels and restaurants, industry, and residential sectors on a national level, up to 2040. Demand forecast in the residential sector is based on historic energy consumption growth in the sector, while consumption in the other sectors are a function of their respective real GDP growth and energy intensity.

With MESBE's agreement, we have made significant updates to the LINDA model in order to improve long-term planning for new technologies and changes in consumers electricity consumption patterns. The following updates have been made to the LINDA model:

- Functionality to evaluate two new scenarios (High and Low) of the four sectors.
- Three new electrified sectors; EV, CL, and cooking in residential and commercial sectors.
- Energy savings estimated from the DSM/EE programmes identified in the 2015 DNV-GL study.
- Functionality for user-defined combinations for three demand scenarios.

Electricity demand in Barbados is projected to increase to 1277 GWh in 2030 and 1499 GWh in 2040 under the Base scenario, which is a 35% and 59% increase respectively from its 2019 levels. The commercial and residential sectors currently account for the largest share of electricity demand (37% each), however, this status is expected to change. In the underlying Reference scenario, the commercial sector's electricity intensity is assumed to decrease at an annual rate of 0.3% between 2021 and 2025, while the residential sector experiences a significant annual growth of 2.7% in the same period. The industry, and hotel and restaurants electricity intensity are projected to have an annual growth rate of 2.2% and 1.8% respectively between 2021 and 2025.

The transport sector will see the biggest increase with 264 GWh in 2030 and 455 GWh in 2040 (Base scenario) as EVs are deployed, with the majority of the EV expected to be private cars. This newly electrified transport sector could account for 21% of the total demand of the country by just 2030 with a potential increase of up to 30 MW on peak demand.

The gradual replacement of gas cooking and CL's diesel supply with electricity from the grid, is projected to be 5% and 9% of the total demand in 2030 and 2040 (Base scenarios) respectively. On the other hand, DSM savings through efficiency measures could reduce total demand by 11% and 16% in 2030 and 2040.

Barbados' future power demand will be closely linked to economic drivers but will also be influenced by electrification of new sectors currently served by fossil fuels, most notably the road transport sector. The power demand from 2020 till 2030 will continue to be mainly driven by the commercial and residential sectors, with EV having a significant share from 2030 till 2040. At the same time, we can also expect to see more slow-acting saturation effects and energy efficiency changes in some end-use sectors and potentially more rapid policy-driven changes from DSM/EE programs. All these factors have been considered in framing the demand forecast.

Resource Options Evaluation

5 Resource Options Evaluation

This section evaluates technically feasible supply options of electricity in terms of their estimated cost. This is done here on the basis of Levelised Cost of Energy (LCOE).

LCOE is a constant value that can be thought of as the average minimum price in which the electricity generated by the asset is required to be sold at, in order to offset the total costs of production over its lifetime. More details on LCOE is provided in Appendix 0.

$$(1)\ LCOE = \frac{\sum_{t=0}^{T}\left(\frac{Cost_t}{(1+r)^t}\right)}{\sum_{t=0}^{T}\left(\frac{Energy_t}{(1+r)^t}\right)}$$

5.1 Demand Side Options

An in-depth or ground-up Demand Side Management or Energy Efficiency exercise is outside the scope of this assignment. However, we have reviewed DSM/EE studies done by others such as the DNV GL study [12].

The impact on DSM/EE measures on the Demand Forecast is explained in more detail in Section 4.1.2.4.

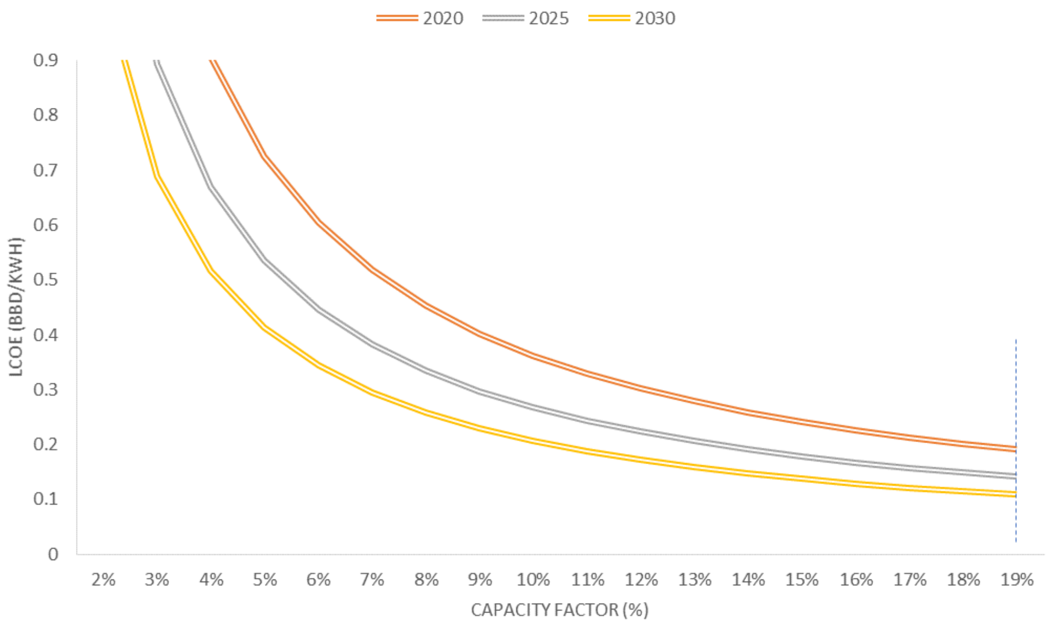
5.2 Supply Side Options

The objective of this section is to assess candidate power generation technologies to be subsequently considered in the expansion planning process. The below analysis serves as a preliminary economic assessment. The assumptions on capital expenditure are listed in Table E.1. Renewable technology capex is expected to decrease over time as supply chains are still developing and scaling up, manufacturing processes improve, and efficiencies increase. Such learning curves can be derived from third party estimates and applied to the relevant technologies.

In terms of operating costs, we have considered fixed and variable operational costs per technology and fuel costs as described in the assumptions used for the Generation Planning Study (refer to Appendix G.1). Emissions cost have been excluded from the LCOE calculations here, but associated volumes of carbon emissions are shown alongside the generation cost where applicable [47, 48, 49, 50].

We start the evaluation by assessing renewable technologies such as solar PV. The yearly cost reduction of these technologies makes them more attractive for investment the closer we get to 2030. The LCOE for different years is shown in Figure 5.1. We can observe the effect of the capital cost decay on the LCOE over time. Note that the LCOE is inversely correlated with the capacity factor, which in turn is limited by the maximum resource availability and technical performance. LCOE values range from 0.43-0.78 BBD/kWh at low-capacity factors (5%) and reach as low as 0.11-0.21 BBD/kWh at maximum availability (19%).

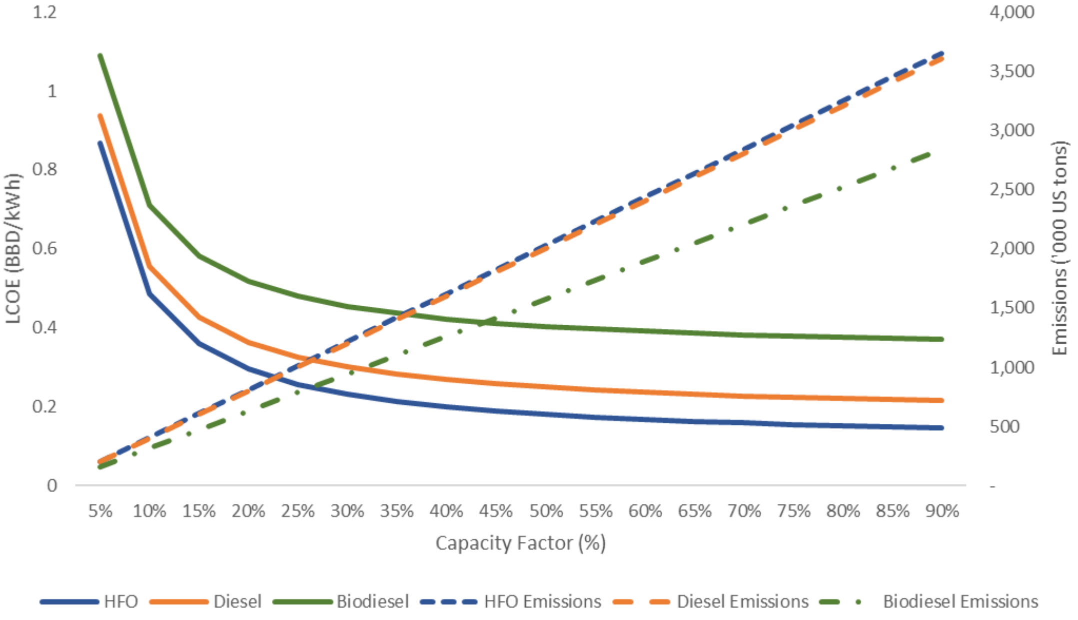
Figure 5.1: Levelised Cost of Energy for Solar PV at different utilisation levels



Source: Mott MacDonald

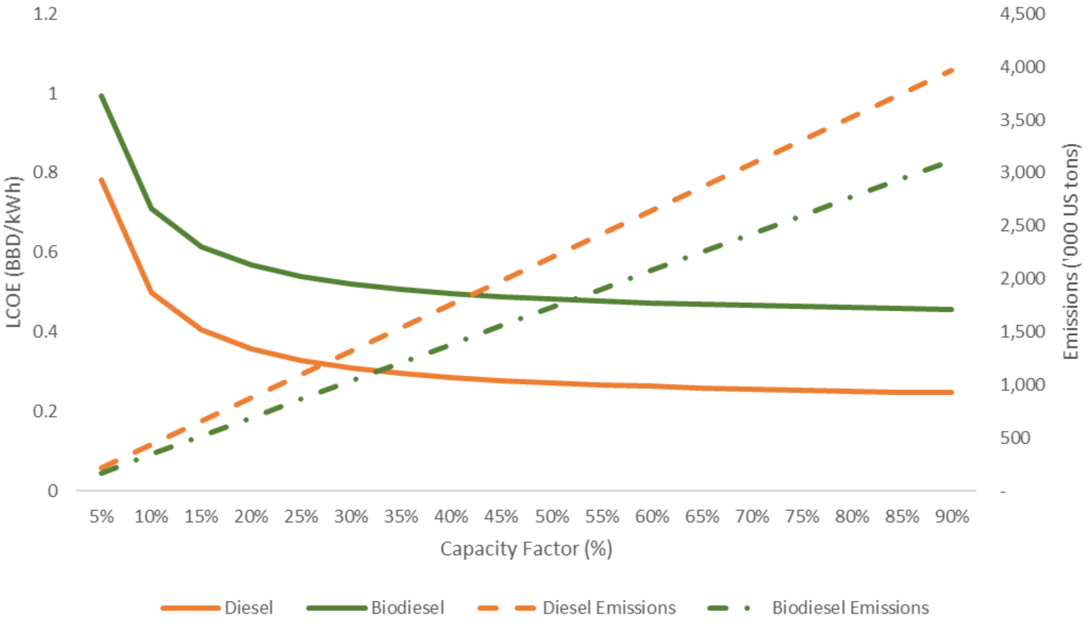
For thermal technologies, the LCOE is affected by the choice of fuel. For internal combustion engines (Figure 5.2) the use of heavy fuel oil is the cheapest resource and results in the lowest LCOE values. For Gas Turbines (Figure 5.3) the use of diesel is the most cost effective with biodiesel resulting in higher levelized cost values. There is a notable difference in CO_2 emissions production with Biodiesel having the least amount of emissions in both cases of ICEs and GTs. However, biodiesel emissions are considered carbon-neutral because they are not of fossil origin, even though we count them as local emissions here.

Figure 5.2: Internal Combustion Engine Levelised Cost of Energy for different fuels and associated emissions



Source: Mott MacDonald

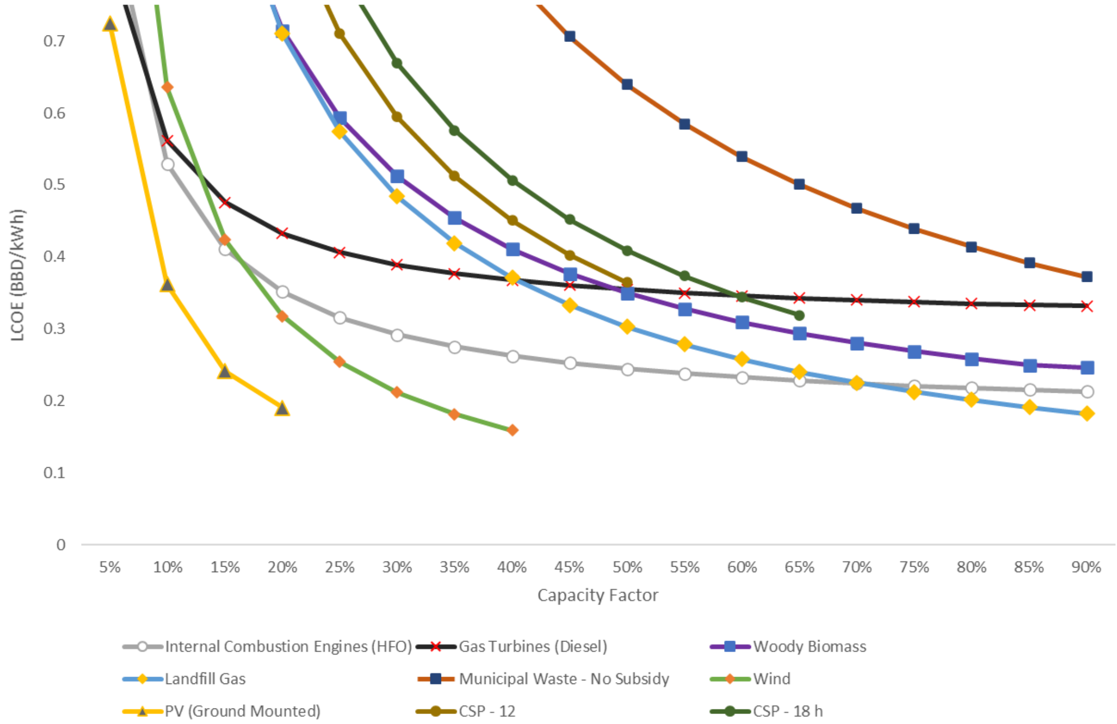
Figure 5.3: Gas Turbine Levelised Cost of Energy for different fuels and associated emissions



Source: Mott MacDonald

We can use a similar approach to conduct a comparative analysis of LCOE across all available candidate generation technologies, namely those listed in Table E.1. The trade-offs between capital costs, operating costs, and utilization levels for various types of generating capacity in the system can be consolidated in a single graphical representation as in Figure 5.4 and Figure 5.5.

Figure 5.4: Levelised cost of energy (2020) at different plant utilisation levels



Source: Mott MacDonald

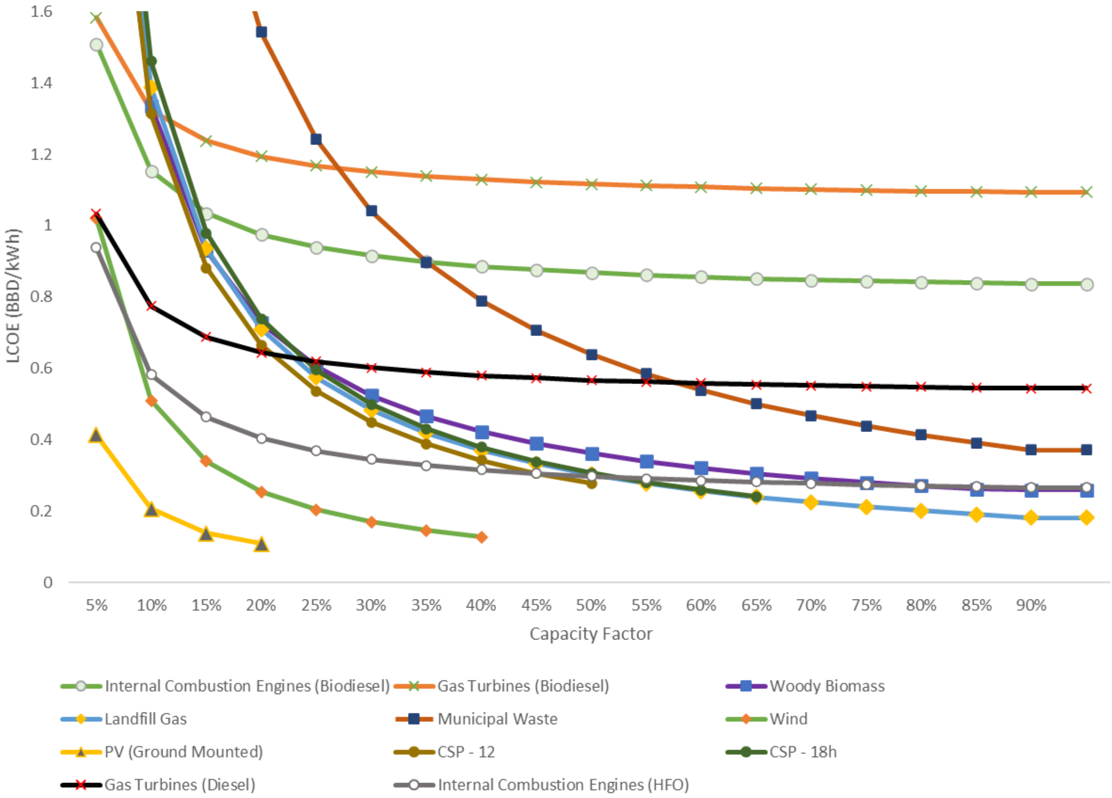
In 2020 solar PV appears to be the cheapest available option, especially at high utilisation factors (10%-19%), i.e., if no capacity is curtailed. Onshore wind generation is the next cheapest available technology, albeit only when it achieves high-capacity factors (above 30%).

For low-capacity factors, the second technology in the merit-order appears to be GTs, which are cheaper than ICEs, however they become more expensive at higher capacity factors (above 5%). This is reflective of the higher efficiency of ICE generators which can make up for the difference in capital and operational expenditure compared to gas turbines. This means that gas generators are more suitable to serve as peaking plants if it is decided to invest early in this technology, whereas ICE would be running as baseload. A similar behaviour is observed for landfill gas technologies which can only be considered economic at very high capacity factors.

Even at maximum availability, projects such as biomass, waste and concentrated solar power are much less economic with municipal waste being the least attractive option. Specifically, we can observe that at 90% availability waste to energy is almost twice as expensive than an ICE generator. This analysis assumes zero cost of fuel for energy to waste; in reality there is often a gate fee associated with waste management in the form of subsidies.

The CSP with 18 hours of energy storage shown is also an expensive option, more expensive than biomass in 2020. CSP with shorter durations of storage, e.g. 12 hours, are cheaper but still less economic than biomass.

Figure 5.5: Levelised cost of energy (2030) at different plant utilisation levels for low-carbon options



Source: Mott MacDonald

In 2030, we can already see the effect of renewable technology costs having decayed over 10 years. In all cases solar PV is projected to be by far the cheapest available option, regardless of the availability factor followed by onshore wind with LCOEs. We would expect that generally the utilisation factors of renewable technologies such as PV and wind will be maximised and that the large differentials in expected cost would also imply storing PV and wind energy will be economic.

The results above further indicate that ICEs running on biodiesel are generally cheaper than GTs running on biodiesel for high-capacity factors. However, both technologies are not cost effective due to the high cost of biodiesel.

The landscape is very similar for biomass, concentrated solar power, waste, and landfill gas which remain less attractive options, with the landfill gas approaching low LCOE values at high capacity factors, similar to the 2020 analysis. The resource for this technology however is usually scarce and there is a lot of uncertainty around the quantity and cost of gas supply. CSP has seen a cost reduction that drops the cost lower than a biomass project and making it competitive with landfill gas. Energy from waste is the most expensive resource assuming zero cost of fuel (no subsidies).

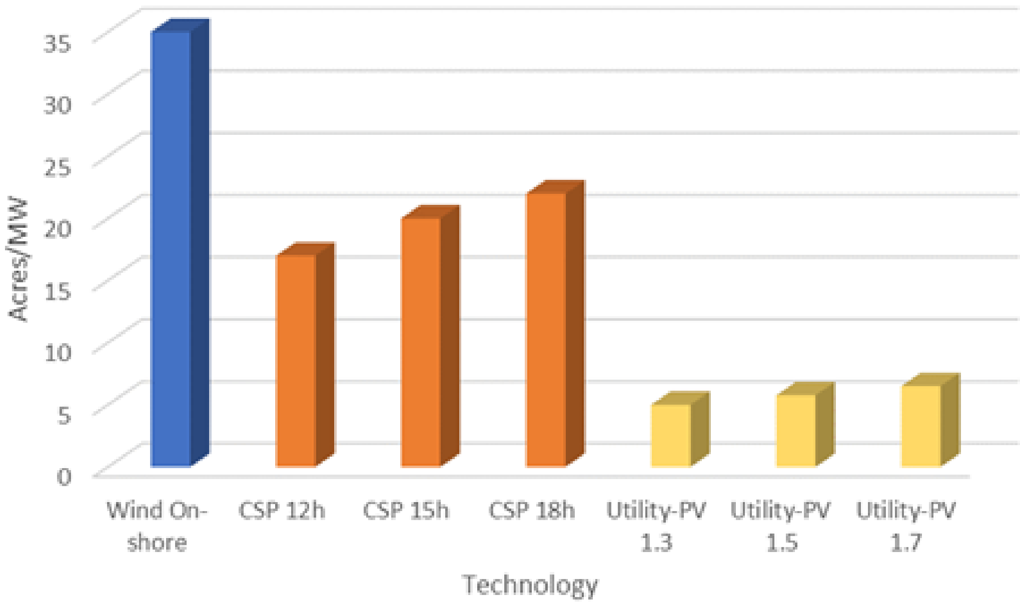
5.2.1 Land Use

While the potential renewable resource on the island of Barbados alone is perhaps several multiples of projected electricity demand (excluding off-shore development potential), land use is an important factor on a small island as there is competition for land from productive agriculture, real estate developments (hotels and tourism establishments, dwellings, commercial, and industrial), and recreational space.

We do not know where these constraints will arise, but total land use will have to be considered in the least-cost generation mix and its negative impact, such as from visual intrusion, will need to be avoided or mitigated.

Figure 5.6 below demonstrates the land requirement per kW of installed peak capacity for different technologies (wind, solar PV with different DC/AC ratios, and CSP with different hours of storage).

Figure 5.6: Estimated Land Requirements per Technology



Source: Mott MacDonald

Onshore wind, due to spacing requirements between turbines in Barbados, has the largest footprint per MW with 35 acres per MW (as an average across a range of turbine sizes (1 MW and 3 MW) and yields). CSP ranges between 17 and 22 acres per MW (increasing with larger thermal energy storage). Solar PV only has a footprint ranging from 5 to 6.5 acres per MW (increasing with larger oversizing ratios).

Stakeholders have fed back during consultation sessions regarding land availability for RE development that an estimated 5000 Ac (20 km^2) would be available for RE development. At the above estimated land requirements, this could equate to ~1 GW of solar PV (~1.752 TWh) or in ~150 MW of wind (~525 GWh) compared to an estimated demand of 1300 GWh by 2030.

In practice, there will of course be a mix between resource allocation due to the complimentary nature of wind and solar resources as we shall see in the next section below.

5.2.2 Resource Analysis and Intermittency

A full solar and wind resource analysis was carried out for Barbados. Key conclusions that can be highlighted here are that Barbados has good solar resource availability throughout the year, although some minor seasonality exists. Similarly, a good wind resource is also present, although the variability across seasons is much stronger than for solar. Wind and solar resources appear complementary to a good degree.

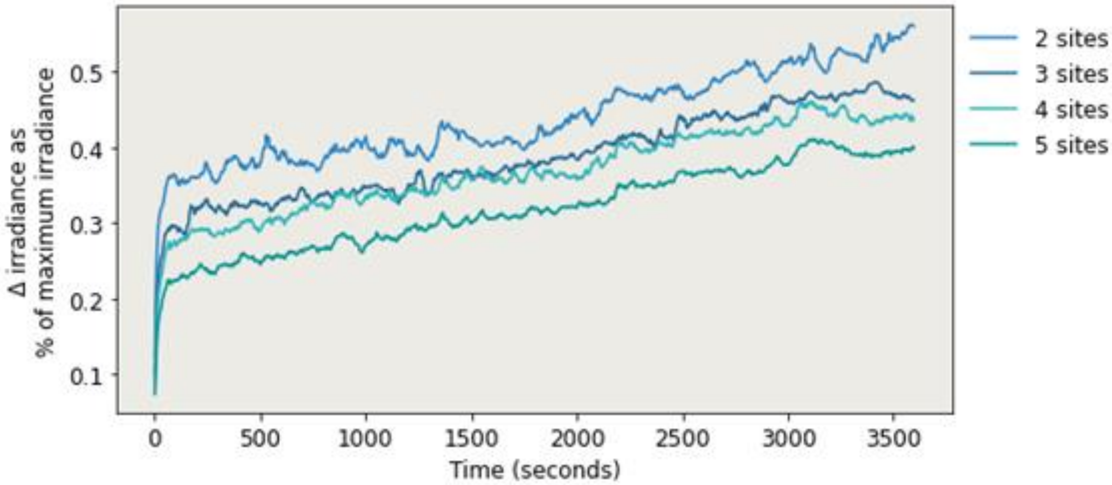
We note that system planners and operates would be expected to have access to more and more detailed data for resource analysis with higher temporal and spatial resolution. Note our recommendation in respect of this aspect, in particular in relation to reserve dimensioning for the future.

For the solar resource intermittency, we have analysed five irradiance profiles expressed at one-minute intervals and measured by different pyranometers from across the island. Whilst this dataset is limited in that it only covers five different, it highlights the smoothing effect that is inherent to the geographical dispersion of solar resources across short time horizons.

This is visible in Figure 5.7, whereby a clear decrease in the magnitude can be observed in the resource intermittency when the irradiance profile is aggregated across multiple sites. The distance between the sites matters also as can be seen from the comparison of the reduction achieved by adding a fourth site to the three-site portfolio, which is nearby, versus the significantly greater reduction achieved by adding the fifth site, which is farther away.

This graph also highlights how increasingly extreme changes in irradiance would be observed when measured across increasing different time horizons. Nonetheless, the steepest ramping occurs within the first minute, which poses the greatest challenge for system balancing.

Figure 5.7: 99th percentile of the absolute change in solar irradiance measured across different time intervals



Source: BLPC Plexos Model

5.2.3 Technologies

As part of the future supply options, technologies that would be compatible with the BNEP 2019-2030 are considered in this Final Report. While this is not an exhaustive list of potential future technologies, it considers a range of applicable and proven technologies over the study horizon to 2030. Not all technologies however can be considered for Barbados without further studies.

The discussion on the full list of generation technology options is included in Appendix E.

5.3 Conclusion

We have conducted a first-step evaluation of different feasible supply options for the energy landscape of Barbados. It is evident from the analysis that renewable energy options in the form of solar PV and wind are the two most attractive options in terms of minimising the cost of energy supply to the island, with their projected costs decreasing in the future to decrease making them even more economic.

Further studies of the solar and wind resources have shown that while there is promising resource potential, the intermittent nature of the renewable output can be quite significant which poses a risk for the balancing of the system.

Certain consideration needs to be given towards the implications of renewable technology uptake, with regards to the associated land uptake. These implications arise from externalities that go beyond power system planning, however they are important to be taken into account due to their societal and environmental impact.

For fuel-based technologies, internal combustion engines can be used as a reliable source of supply and is the most economic thermal technology when utilised high-capacity factors. In contrast, usage of gas turbines can be justified for peaking periods as this appears to be the most economic use case for this technology. Resource options that are based on liquid biofuels are not expected to play a role in a least-cost energy mix due to the high costs associated with their imports (e.g., ethanol). Should these costs drop significantly in the future, or if the cost of emissions becomes high enough, then these technologies could become attractive as alternative, low-emission options for Barbados.

Energy Storage Technology Study

6 Energy Storage Technology Study

This section of the report assesses the feasibility of storage technologies in Barbados. We present different technologies across a range of scales, power-energy ratings, and round-trip-efficiencies. These are assessed based on cost and applicability in Barbados with a view on energy security and resilience.

6.1 Introduction

With the implementation of the BNEP 2019-2030, the delivery of power across the electrical grid is going to radically change; traditional dispatchable thermal generation will be largely phased out and replaced by intermittent renewable technologies. Many of the services provided by the traditional generators will also disappear with them but are vital to support the integrity of the electrical grid.

The selection of the storage system depends mainly on the application; these range from bulk energy storage provision with long-duration energy capacity to stabilization of the transmission network which requires large power ratings with short-duration storage. The main function of energy storage is to balance demand and supply over different horizons and durations.

Performance factors such as energy and power density are some of the main technical requirements of the energy storage system to meet their objectives, where sizing is typically expressed in terms of power ratings (MW discharge and charge) and energy storage capacity (MWh of energy held). Often, energy storage capacity is also expressed in duration of discharge at rated power capacity. Other performance factors include the round-trip efficiency, expressed as percentage of energy out vs energy in (% between 0 and 100), and the useful life in terms of cycling age, where one cycle is equivalent to one full charge and discharge (usually on the basis of energy throughput rather than actual cycling). Also, response times with which energy storage assets can discharge or charge in response to a signal is a crucial factor in determining their application.

In the context of Barbados future energy system, the main objectives of energy storage system are summarised below for the specific application in the categories of bulk energy storage and distributed storage.

Table 6.1: Energy Storage Applications in Barbados

Category	Application	Energy Storage Capacity	Suitable Technologies
Bulk energy storage (grid connected)	Time shifting of demands and resources over horizons of hours, days, weeks, or even seasons, e.g., to use solar energy during the night	4 hours + (days or weeks)	Lithium-ion Battery Storage Technology (for shorter duration storage) Pumped Hydro Storage, Compressed Air Energy Storage (CAES), Flow Battery, Thermal Energy, Hydrogen Energy Storage
Bulk and distributed energy storage	Firming and smoothing of intermittent supply to maintain specific output profile	60-120 minutes	Lithium-ion Battery Storage Technology
	Ramp rate control to mitigate ramping of renewables (e.g., morning and evening for solar PV)	30-60 minutes	Lithium-ion Battery Storage Technology

Category	Application	Energy Storage Capacity	Suitable Technologies
	Frequency Response to maintain grid stability by correcting over - and underfrequency	<1 second-30 minutes	Lithium-ion Battery Storage Technology

6.2 Storage Technologies Feasibility

We have considered and discussed the feasibility of different identified energy storage options in Barbados which is presented in detail in Appendix F.1. Advantageous and Disadvantages for each are included alongside the recommendation with respect to feasibility in Barbados. In the next section, we summarise the results within a comparative analysis.

6.3 Comparative Analysis

We present an overview of relevant considerations within this scope for the feasibility of storage technologies in Barbados alongside a cost estimate for the assumed used case in Table 6.2 below for 2030. The considerations are capital investment cost, round-trip efficiency (i.e., MWh of generation per MWh of charging), useful asset life, commercial readiness (mature versus emerging technology), Barbados specific challenges (such as geology and geography), impact on resiliency (through modular and distributed deployment), and impact on transmission infrastructure requirements.

All capex estimates are indicative only and subject to considerable uncertainty arising from the degree of cost reduction over the next decade, consideration of emerging technologies which are yet to mature, and specifics of the application in Barbados.

In order to estimate Levelised Cost of Storage (LCOS) for each of the storage technologies considered here, a use case needs to be assumed which we have developed based on the following:

- The Demand Forecast (section 4 above) and the Resource Options Evaluation (section 5 above) allows us to construct a plausible use case on the basis of which to evaluate different energy storage options without needing to conduct full system modelling of all options.
- By 2030, Barbados electricity demand is expected to reach ~1300 GWh annually with a peak demand of ~200 MW. This translates to a Load Factor of ~75%.
- The cheapest supply option is solar PV with a capacity factor of ~25%.
- A very crude least-cost expansion method would suggest that the country would simply require three times the load in terms of solar PV capacity in order to achieve its energy requirements (75% / 25% = 3), i.e., 600 MWp.
- Given that solar PV generates only during the day and not at night, it will therefore be required to supply 12 hours each day via some form of bulk energy storage. That means the expected throughput via energy storage is in the order of 750 GWh annually for a storage system that can absorb all excess energy from solar PV via charging during the day and discharging in the night.
- The system would be sized at 400 MW / 4800 MWh (600 MWp solar PV minus 200 MW load available for 12-hour discharge), which results in a utilisation factor of 42%.

Based on this use case, we can calculate an estimated LCOS. For simplicity, we assume here that energy to charge the storage will be free. The LCOS spreads the capex and operating cost of the storage system evenly across the energy throughput (i.e., charged, stored, and release energy via the system) to arrive at a cost per kWh put through the system.

Table 6.2: Comparative Feasibility of Storage Technologies for long-duration bulk storage over 12 hours in Barbados

Technology	2030 Capex Estimate	Round-Trip-Efficiency (%)	Useful Life (on use case)	Commercial Readiness	Barbados specific challenges	Positive Impact on Resiliency	Positive Impact on Transmission	2030 LCOS (USDc/kWh)
Li-Ion battery	USD/kWh 100-200*	90	15 years	Yes – fully mature	No	Yes, through modular and distributed deployment	Yes - can be distributed to minimise transmission requirements	3.2-6.4
Flow Batteries	USD/kWh 100-500	~80%	15-20 years	Commercially available at scale but no proven track record.	No	Yes, but chemical hazards likely lead to less distributed deployment	Yes - can be distributed to minimise transmission requirements	3.7-18.5
Hydro Pumped Storage	USD/kW 3000-6000	~75%	30 years+	Yes – fully mature	Yes	No	No – concentrated at location. Likely to require new transmission infrastructure.	4.2-8.4
Compressed Air Energy Storage	USD/kW 1,000 + USD/MWh 30	~65%	25 years+	Commercially available at scale but no proven track record.	Yes	No	No – concentrated at location. Likely to require new transmission infrastructure.	~3.00
Thermal Energy Storage	USD/kW 1,000 + USD/MWh 30	~65%	20 years+	Commercially available at scale but no proven track record.	No	Yes, can be modularly deployed and distributed	Yes - can be distributed to minimise transmission requirements	~4.1
Hydrogen Storage using electrolyser and fuel cell	USD/kW 2,000-4000	~45%	15 years	Commercially available but no track record in this application	No	Yes, can be deployed on distributed basis	Yes – can be distributed to minimise transmission requirements	~8.1 –16.2

The LCOS of Li-ion in 2030 for 12 hours of storage is estimated to be in the same potential range as the other technologies (CAES, flow batteries, pumped hydro, and thermal energy storage), as such we will consider Li-ion as the candidate storage technology. The other technologies as applicable can be evaluated closer to the time of installation and as they mature over time.

6.4 Conclusions

This section highlighted that for shorter duration storage (<4 hours) Li-ion is the dominant technology, which is also highly competitive in terms of cost, both today and in future. The technology has been benefiting from the investment, innovation, and large-scale manufacturing mainly driven by the automotive industry in developing competitive e-mobility. There are a number of potential alternative solutions; however, of these only Li-ion has a proven track record while scoring well on the other factors considered in the context of Barbados.

While many storage technologies such as HPS, CAES, and thermal based systems have been developed, many are still limited with respect to their response capabilities, siting, and capacity flexibility. Electrochemical energy storage is capable of meeting a far wider range of capability than many alternatives and this capability is developing rapidly as battery storage is seen as very much the future across a range of applications from transportation to the electrical grid systems. BESSs have a long track record of implementation for grid applications and costs have recently been in rapid decline while performance and life expectancy continue to increase.

At the moment, Li-Ion battery storage is the only mature and proven technology which can cover the whole range of required storage applications. This may change as technology development advances and feasibility studies shed more light on the options available to Barbados. In the near term, for bulk storage application, HPS could be competitive option, and in the future also Flow Batteries, CAES, and thermal storage may become suitable options.

However, from a resiliency and transmission network perspective, modular, and distributed solutions would be preferred, which currently leaves only Li-Ion battery storage as an option with the following advantages:

- Optimal use of existing network capacity with less overloading and reduced transmission losses
- Supporting electrical islanding by balancing geographically dispersed generation and loads across the island

In principle, it does not matter where and what type of energy storage is connected so long as the system controls and performance allow it to meet the requirements of the intended application. The clearly feasible alternatives for Barbados are:

- Utility-scale battery storage systems (10-30 MW) that are distributed across the island; and
- Distributed home energy storage (thousands of small-scale systems in the kW range).

Utility-scale energy storage typically provides cost advantages due to scale, while distributed energy storage on the other hand can be more resilient in performing the same function when it acts as a “virtual power plant”. Multiple small, distributed units can have the same cumulative effect on the grid supply and demand balance as a single unit of the same size. It is more important that the size of the storage systems is proportional to the needs of the balancing area within which it is installed.

Generation Planning Study

7 Generation Planning Study

This section provides an analysis of the generation planning results. The assumptions and scenarios modelled have been agreed and finalised with MESBE. The model has been calibrated for accuracy and performance. Assumptions that have gone into this study and an outline of the methodology are available in Appendix G.

7.1 Scenario Assumptions

The IRRP spans a 10-year horizon from 01/01/2021 to 31/12/2030 which is the timeframe over which the BNEP 2019-2030 is set out to be implemented.

The three scenarios investigated are summarized below.

Table 7.1: Planning Scenarios

ID	Scenario	Description
1	Least-cost plan (LCP)	Baseline scenario without policy intervention for reference. Carbon is priced for accounting purposes but otherwise externalised, i.e., not a driver for build and dispatch decisions.
2	Carbon Cost internalised (CO2)	Policy intervention implemented via a Carbon Price. The Carbon Price is internalised into build and dispatch decisions.
3	Forced Firm Renewable Scenario with Carbon Cost internalised (FRES)	Policy intervention implemented via a Carbon Price. The Carbon Price is internalised into build and dispatch decisions. In addition, firm renewable resources are enforced into the plan as follows: • A maximum of two Biomass plants of 10 MW each or a minimum of one Biomass Plant of 10 MW can be built, one of which must be built by 2025. • A maximum of five Landfill Gas plants of 1 MW each can be built from 2023 and must be built by 2025. • A maximum of one Waste to Energy plant of 8 MW can be built from 2023 and must be built by 2025. A choice must be made between a baseload or a more flexible technology type.

Source: Mott MacDonald

The robustness of the results of each scenario were tested with various sensitivities. The range of values used for each planning parameter in the sensitivity analysis is described in Appendix G.1.1 below. The high and load demand assumptions can be found in section 4 above.

We have considered the resilience of the different scenarios by taking into account key aspects of a number of the assumptions in this study as follows:

- Resilience was considered in the Capex assumptions, by including a small Capex premium for RE plants like Solar PV and Wind, as they could be susceptible to hurricanes and other weather phenomena;
- Resilience is considered in ensuring that there was a high level of optionality in energy sources with comparatively shorter build time (such as solar PV);
- Resilience was considered in terms of economic shock of oil prices by ensuring a certain level of RES was integrated in the grid; and
- Resilience was considered in the sensitivity analysis by adjusting the assumptions of input parameters (see Table 7.2).

Table 7.2: Scenario sensitivity matrix

Scenario name	Load High	Load Low	Capex High	Capex Low	WACC High	WACC Low	Fuel Price High	Fuel Price Low	Carbon Price High	Carbon Price Low
LCP[4]	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
CO2	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
FRES	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

Source: Mott MacDonald

7.2 Results

The generation planning results start with a comparative overview of all scenarios in section 7.2.1, highlighting the key results across the scenarios analysed. Section 7.2.2 analyses each base scenario in greater detail for parameters of interest. The results of the sensitivity analysis are presented in section 7.2.2.8, where the variables such as load, capex, WACC, fuel price and carbon price were tested on all three scenarios.

The results presented here are non-inclusive of transmission equipment, with the exception of the build and operating cost of synchronous condensers. For grid support requirements, please refer to section 8 below.

7.2.1 Results overview – All base scenarios

7.2.1.1 Key performance indicators

Table 7.3 summarises the key performance indicators (KPI) for each scenario. These include the NPV, relative NPV (as a percentage increase of the least cost plan – scenario 1), total cumulative CO2 emissions over the planning horizon (2021 -2030) and the implied carbon reduction cost (ΔNPV/Δ cumulative CO2 emissions).

Table 7.3: Scenario summary by key performance indicators

Scenario	NPV (Billion BBD)	Relative NPV (%)	Carbon Emissions (Million tons)	Implied carbon reduction cost (BBD/kg)
1 LCP	13.48	-	3 740	-
2 CO2	13.96	3.50	3 039	0.67
3 FRES	15.44	14.53	2 758	2.00

Source: Mott MacDonald

In scenario 1, the reference scenario, carbon emissions cost is externalised, and the carbon emissions are therefore not a driver of build or dispatch decisions. Nonetheless, for the comparison of the three scenarios, we have adjusted the NPV to account for the cost of carbon emissions. On the basis of a comparison between scenario 2 and 3, respectively, with the reference scenario 1, we can calculate the implied cost of carbon emissions reduction; that is the costs incurred related to the reduction of carbon emissions compared to scenario 1 which does not take any action to actively reduce carbon emissions.

Scenario 1 has an NPV of BBD 13.48 billion (adjusted to include carbon emissions cost) and associated cumulative carbon emissions of 3 740 million tons over the planning horizon.

[4] As the Carbon Price is for Accounting Purposes only and not used in build or dispatch decisions, there is no impact on the plan from a Carbon Price Sensitivity.

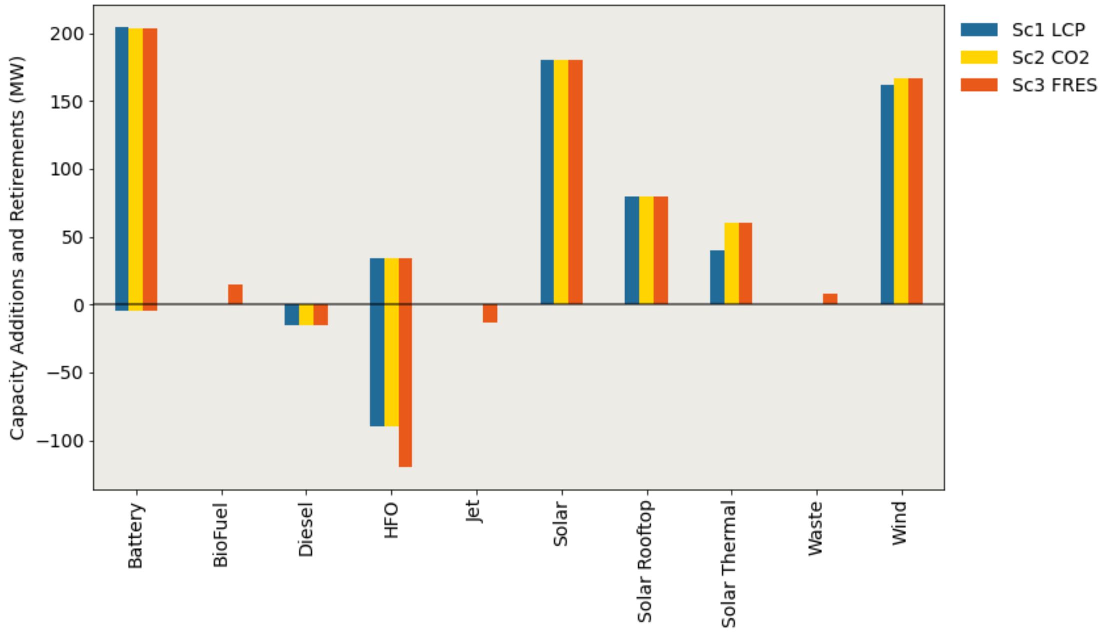
Internalising the cost of carbon emissions in scenario 2 increases the NPV by 3.5% to BBD 13.96 billion. Cumulative carbon emissions are reduced by 19% resulting in a cost of carbon emissions reduction of BBD 0.67/kg of CO2 reduced. This is achieved by building more onshore wind capacity as well as CSP.

Scenario 3 NPV is BBD 15.44 billion, this is at a 14.5% premium over scenario 1. The implied carbon emissions reduction cost is BBD 2.00/kg of CO2. Scenario 3 achieves the lowest carbon emissions because of more aggressive retirement of HFO plant which is feasible because of firm renewable energy being introduced in this scenario.

7.2.1.2 Capacity additions and retirements

Figure 7.1 below compares the cumulative capacity additions and retirements in MW by fuel type for all three base case scenarios. Solar thermal refers to CSP and solar generally refers to ground mounted solar PV. Biofuel refers to biodiesel and waste represents land gas and waste to energy plant.

Figure 7.1: All base scenarios – Cumulative Capacity additions and retirements



Source: Mott MacDonald

The cumulative capacity additions and retirements over the 2021 to 2030 horizon are very similar across scenarios and almost identical when it comes to Solar PV and Wind; clearly these resources are the least-cost options for Barbados and therefore any least-cost expansion plan (regardless of considerations for carbon emissions) would maximise the use of these. Battery energy storage cumulative capacity is also almost identical across scenarios as these are necessary to integrate the variable renewable resources, albeit noting the uncertainty at this point around the level of secondary reserve being ultimately required (refer to discussion in Appendix section G.1.2.5 and analysis in Appendix section G.3).

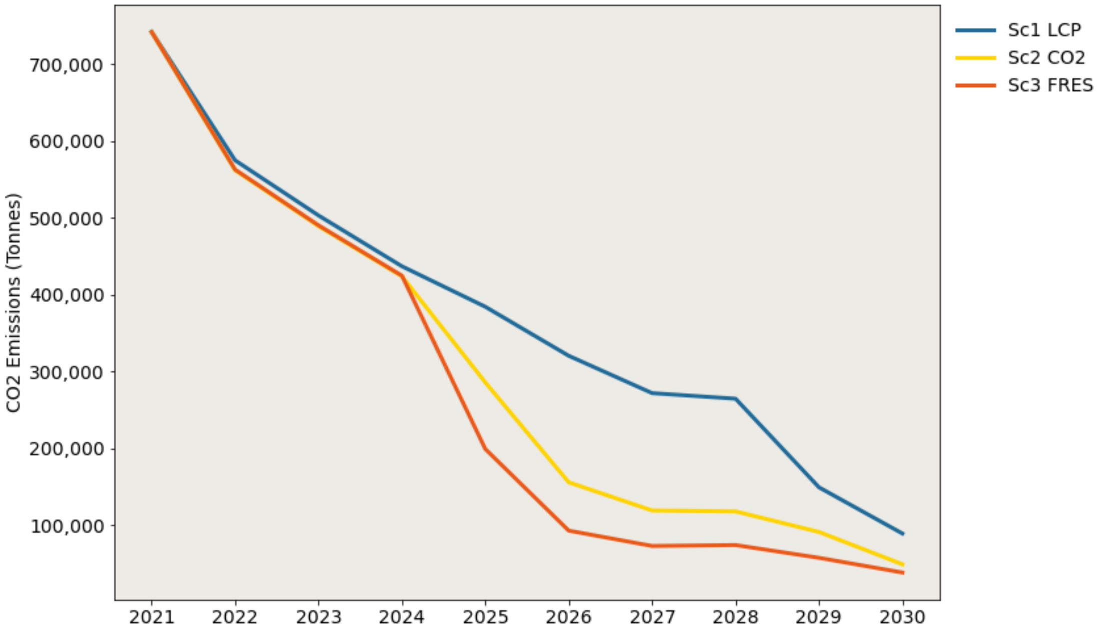
Scenario 3 allows for more HFO units to be retired due to the addition of firm renewable generation in the form of waste and biomass. Retirement across all scenarios are driven by age, operating economics, and reliability of the units. Scenarios 2 and 3 build 20 MW more CSP and 5 MW of wind than scenario 1 in response to the carbon price constraint.

The overall capacity additions are around 640 MW compared to the peak load being around 260 MW by 2030. Around one third of this capacity is battery storage and the remaining being generation plants.

7.2.1.3 Carbon emissions

The annual carbon emissions for each base case scenario are presented by Figure 7.2 below. Current (2021) carbon emissions due to power generation amount to approximately 740 thousand tonnes. Under all three scenario emissions gradually decreases over time and as expected scenario 2 and 3 emissions are reduced at a steeper rate due to the carbon emissions cost being internalised into the build and dispatch decisions. Scenario 1 and 2 sees emissions fall to 12% and 6.7% of current levels, respectively. However, scenario 3 achieves the lowest emissions by 2030, reducing to 5% of current levels.

Figure 7.2: All base scenario – Carbon emissions

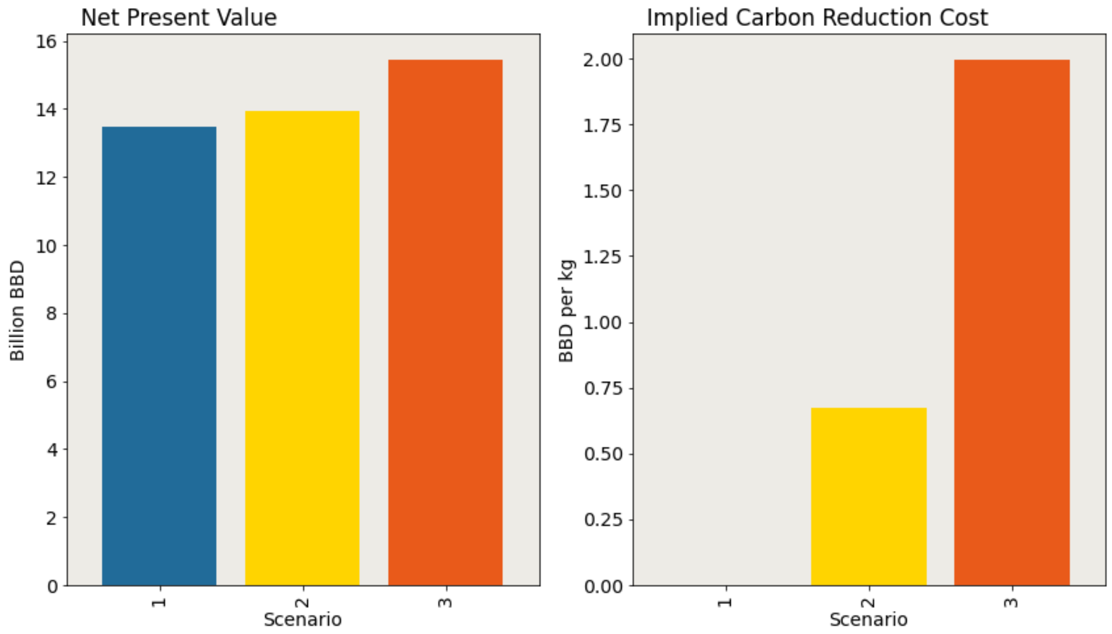


Source: Mott MacDonald

The cost of achieving the reduced carbon emissions relative to Scenario 1 are shown in Figure 7.3. Scenario 3 has an implied carbon reduction cost three times higher than scenario 2. This shows that Scenario 2 offers a more cost-effective solution to carbon emissions reduction. Although the NPV for Scenario 3 is only 10.8% higher than Scenario 2, the cost of carbon emissions reduction shows that there are decreasing marginal returns to carbon emissions reduction investments, which is generally a well-known phenomenon.

In Barbados, the evidence obtained through the modelling described in this report shows that the first 88% of decarbonisation is achieved without needing to pay any premium over what a least-cost plan would do regardless. The next 5% of decarbonisation (93.3% decarbonisation) results only in a 3.5% NPV premium and Scenario 3 achieves a 95% decarbonisation at an additional 10.7% premium (total premium of 14.5%). It is noted that none of the scenarios achieved a 100% decarbonisation as set out in the Barbados New Energy Policy and that it would require increasingly higher premia to achieve this.

Figure 7.3: NPV and cost of CO2 reduction



Source: Mott MacDonald

7.2.1.4 Reliability

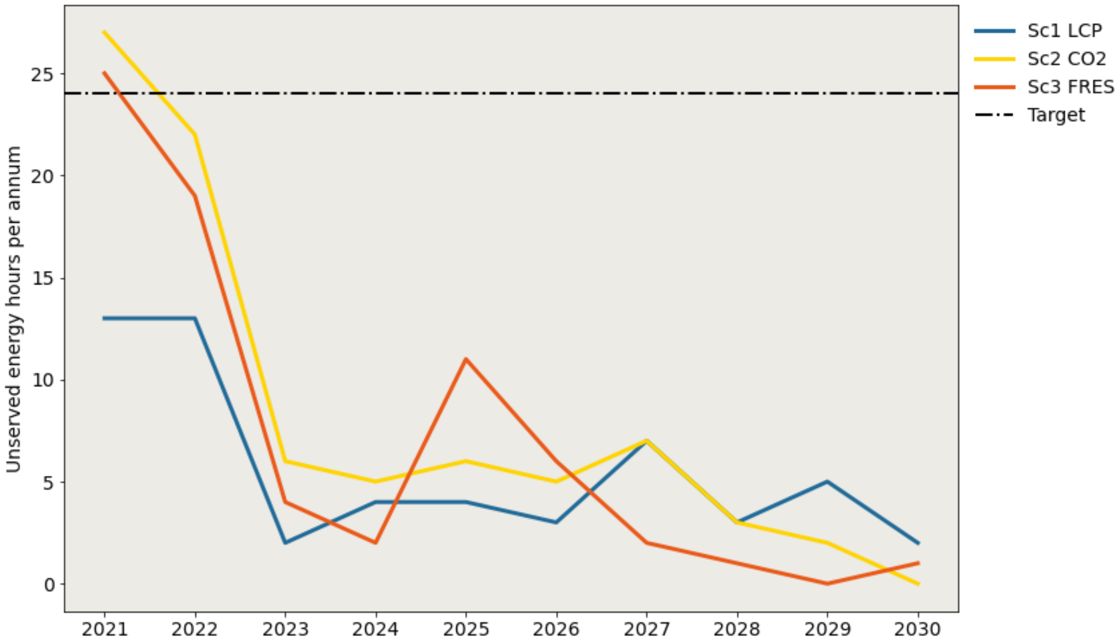
A key performance metric when comparing power systems and different expansion scenarios is the loss of load probability (LOLP) or loss of load expectation (LOLE), measuring the expected amount of unserved energy in relation to the load. The results are taken from the generation adequacy modelling exercise, i.e., the detailed ST-phase system simulations.

As shown in Figure 7.4, the Barbados system in 2021 currently violates the reliability target by a small margin in Scenarios 2 and 3 whereas in Scenario 1 a LOLE of 14 hours achieved is well within the allowable range. This represents the current reliability of the system as it currently is (i.e., in 2021 all scenarios are identical with the exception of the carbon price being applied to dispatch in Scenarios 2 and 3) noting that the reliability of the system has a stochastic element such that three different instances of the same system modelled can result in slightly different outcomes. The average across the three scenarios for 2021 results in a LOLE of 22 hours which is within the allowable range.

Over the rest of the planning horizon, all scenarios meet the regulatory requirement of staying below 24 hours per year and reliability generally increases over time compared to current levels. This is particularly achieved by the phasing out of the least reliable plant present in the system now as well as the modularity of the new technologies replacing them resulting overall in higher reliability.

When planning a system that largely relies on variable renewable resources, there is a strong inverse relationship between the level of reliability and the capacity curtailed. We explore this further in the next section.

Figure 7.4: All base scenario – Unserved energy hours



Source: Mott MacDonald

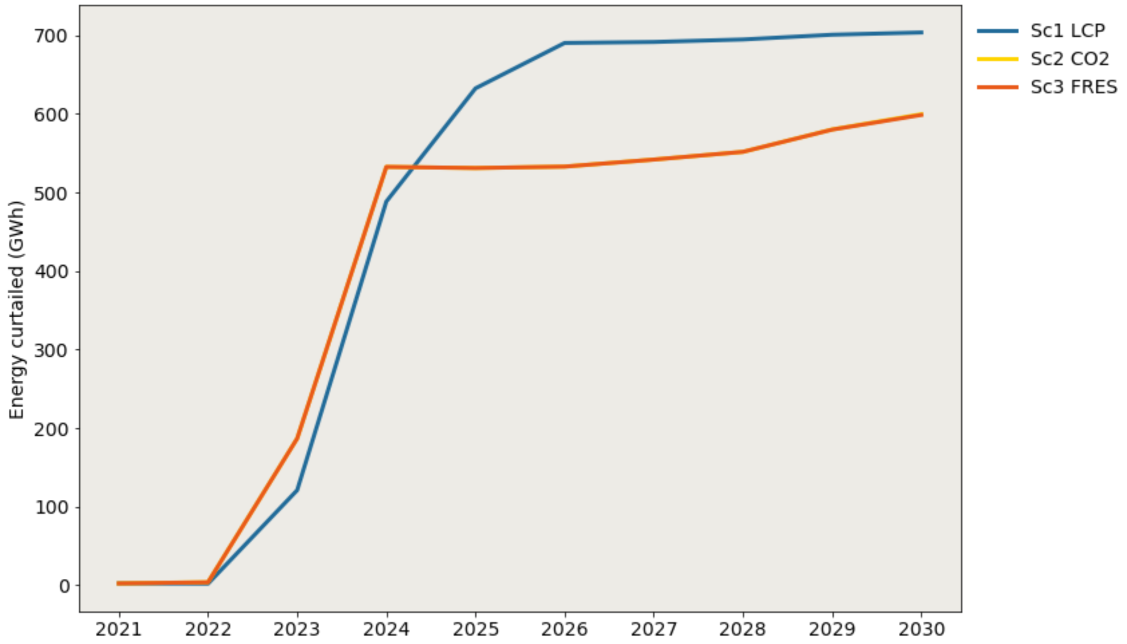
7.2.1.5 Curtailment

Figure 7.5 shows the projected level of generation capacity curtailed in GWh for each of the three base scenarios. This shows a picture of generally rising levels of curtailment in all scenarios with Scenarios 1 and 2, being nearly identical, reaching 700 GWh in 2025 with minimal increases in curtailment to 2030. Scenario 3 sees a steep increase in curtailment until 2025, after which curtailment rises at a steadier rate. This corresponds to the waste and biodiesel plants coming online in 2025, higher level of dispatchable generation in this scenario compared to Scenario 1 and 2 explains the lower level of curtailment.

Note that it will be optimal to accept a level of curtailment given that a particular reliability needs to be achieved because it is usually cheaper to curtail energy than storing it. This is particularly the case for seasonal balancing of energy demand and supply because it is very costly to move energy from months with abundant sunshine and wind to months with less renewable resource availability but also applies in the short-term. To ensure year-round (or all week) security of supply, the capacity of renewable energy needs to be sufficiently large to meet demand even in those low renewable energy periods (e.g., the non-windy night) and thus necessarily resulting in curtailed energy generation capacity during abundant periods.

It should further be noted that curtailed renewable energy capacity can be utilised for providing operating reserves. In this IRRP study, conservatively we have not assumed this to be the case for Barbados as the operating system and the renewable generators will need to be equipped to be able to do this. However, there are a number of countries that have already or are introducing this mechanism over the coming years. The effect of this would be an additional use case for renewable generators in providing ancillary services which in turn reduces the requirement of battery storage installations.

Figure 7.5: All base scenarios – Energy curtailed



Source: Mott MacDonald

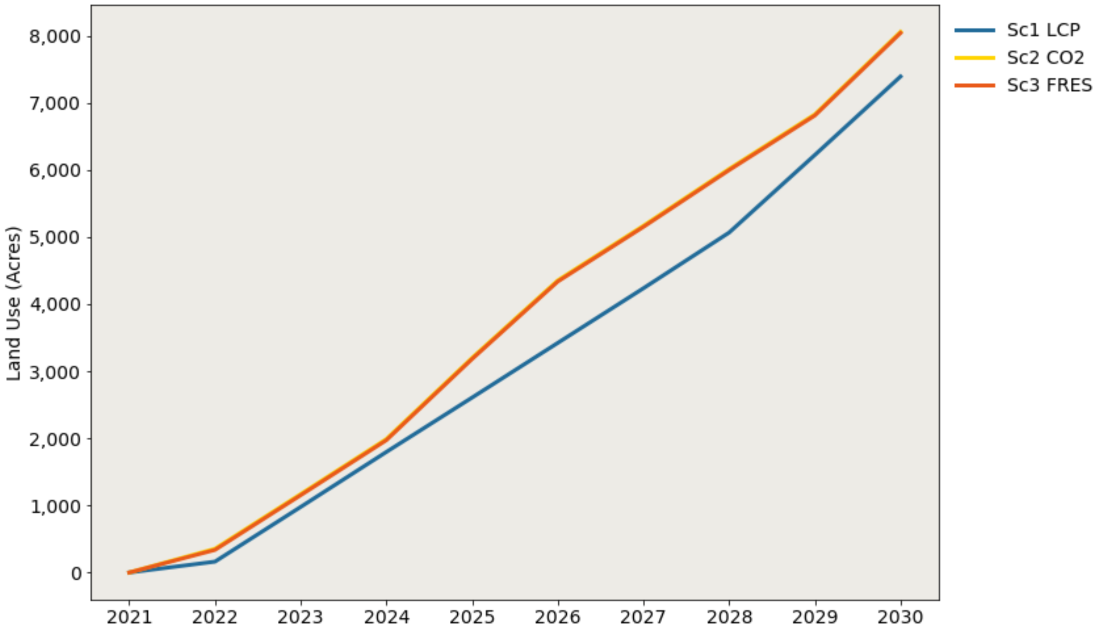
7.2.1.6 Land requirement

The growth of renewables absorbs considerable land area, and this is seen in the continuing increase in land take across all scenarios as shown in Figure 7.6. We consider here explicitly the land used for the purpose installing on-shore wind, solar PV, and CSP excluding indirect land use for biomass and fuel crop production which would be additional land take in Scenario 3. We assume here as well that land would only be used for a single purpose whereas in practice PV, wind, and agricultural uses of land could be shared to some extent on the same land.

Due to similarity in builds between Scenarios 2 and 3, the land requirement for these two scenarios reach a maximum of approximately 8 059 acres by 2030, while Scenario 1 requires approximately 7 400 acres by 2030. Scenario 3 requires CSP plants with a lower storage specification, therefore Scenario 3 land use is 100 acres less than scenario 2 by 2030.

Indirect land use for fuel crop production is estimated to amount to an additional 5,000 acres (assuming up to 500 acres per MW in baseload operation) for Scenario 3.

Figure 7.6: All base scenarios – Land use



Source: Mott MacDonald

7.2.2 Detailed results analysis – Individual scenarios

In this section, we present more detailed results of the different scenarios broken down by year.

The focus is on the three main scenarios where we will analyse the capacity expansion and retirements, investment and operating costs, generation mix and typical dispatch analysis and curtailment, reliability, and operating constraints.

7.2.2.1 Capacity additions and retirements

Figure 7.7 below shows the capacity additions and retirements for Scenario 1. The LCP sees the replacement of end of life HFO plant with new HFO generating plant early on but otherwise relies entirely on Solar PV and Wind capacity additions which are incrementally added starting from 2022. From 2029, some CSP is added at the end of the horizon. This large amount of variable renewable energy (VRE) necessitates a large build of battery storage with a significant amount already being built in 2022 and 2023; this is further discussed in section 7.2.2.8 below.

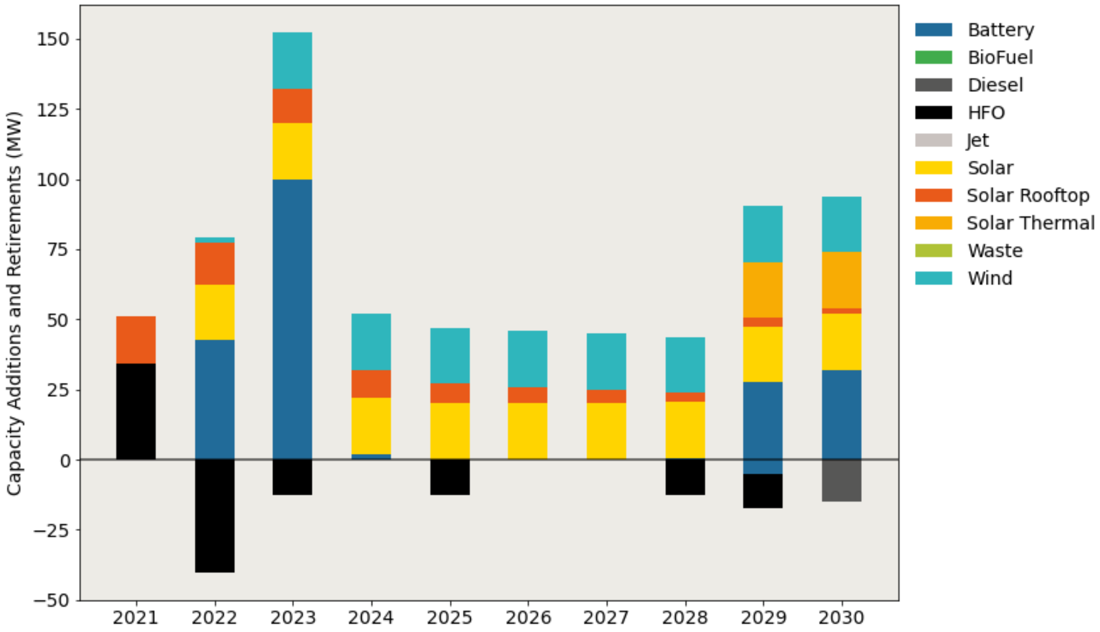
The HFO plant built in 2021 is the Resiliency Bridge. Existing plants were allowed to freely choose when to retire. As such some plant deviated from the BLPC retirement plan. Units S1 and S2 retire in 2022 in line with BLPC's plan. In the subsequent years D10 to D13 retire in 2023, 2025, 2028 and 2029. These units were originally planned to retire in 2028, therefore 2 units retired early, one on time and one retired one year later. In 2029, the existing Trents battery storage system retires as expected as the battery has reached its technical life. The small diesel unit BLPC recently (2020) commissioned is due to retire at the end of the planning horizon.

The ground mounted solar PV technology selected in this scenario comprises those with a DC/AC ratio of 1.3 in 2022, the majority has a DC/AC ratio of 1.5 with some 1.7 selected at the end of the horizon. As the system saturates with PV installations, technologies with a flatter and wider generation profile, albeit more expensive, are preferrable as more energy is available than is needed and less energy curtailed when widely available.

The battery technology picked is all lithium-ion with three and four-hours duration storage. The four-hour battery is built throughout the planning horizon and 50 MW of the three-hour battery is built in 2023. The battery energy storage provides multiple functions in providing necessary operating reserves, smoothening, and firming of renewable output but also, given the longer duration, allows for significant absorption of renewable energy during the day when it is available and shifting it into the night when it is not.

Two CSP units are added, one in 2029 and another in 2030. The CSP technology picked has 12 hours of thermal energy storage.

Figure 7.7: Scenario 1 – Capacity additions and retirements

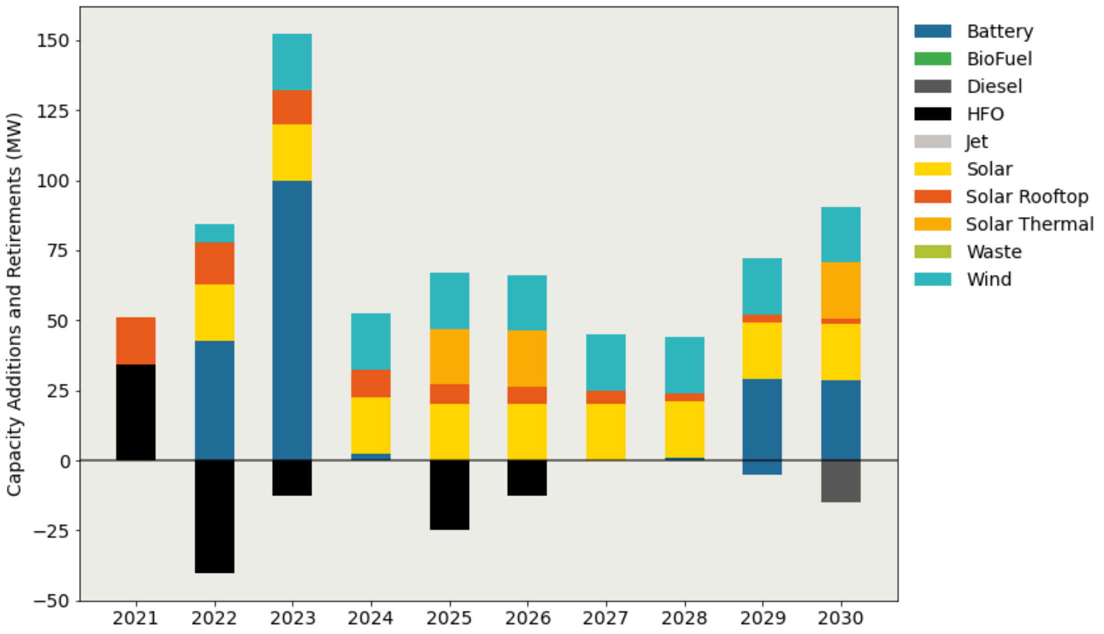


Source: Mott MacDonald

As seen in Figure 7.8, Scenario 2 is broadly similar to Scenario 1 regarding selected technologies, however there are some differences in the timing where HFO units are retired earlier (by 2026). The earlier retirement is due to the carbon price constraint, motivating the model to build renewables to reduce carbon emissions and reduce operating costs. The capacity that makes up for this difference is an additional CSP plant that is also brought forward. CSP with 15-hour duration storage is built in 2025 and 2030, and one with 12-hour storage is built in 2026, which overall equips the Barbados system with a higher level of thermal storage than Scenario 1 requires.

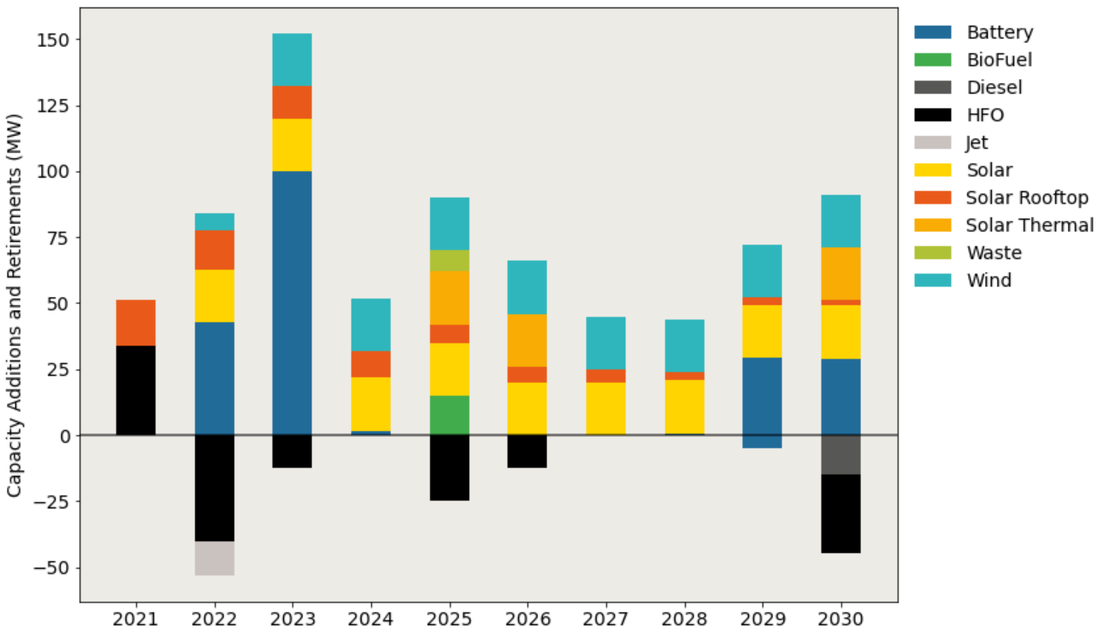
The ground mounted solar PV technology selected here comprises largely of those with a DC/AC ratio of 1.5 with some 1.7 selected from 2028 onwards which means, albeit at slightly cost, Scenario 2 requires higher capacity factors and flatter PV generation profiles compared to Scenario 1. The selected battery technology and quantities are almost identical.

Figure 7.8: Scenario 2 – Capacity additions and retirements



Source: Mott MacDonald

Figure 7.9: Scenario 3 – Capacity additions and retirements



Source: Mott MacDonald

Scenario 3 follows a similar retirement plan to Scenario 2, with the additional retirement of GT02 in 2022. These additional retirements without compromising the reliability of the system is possible because of the forced build of firm renewable generation (waste, landfill gas, and biomass) in this scenario. All landfill gas plant have been delayed as much as possible to 2025, the latest year by which they had to be built. Similarly, the waste and biomass plants were built in 2025. Biomass capacity added is only 10 MW (one out of two candidates) and the second candidate was not added over the horizon to 2030, which is due to the relatively high cost. Ground mounted Solar PV with a DC/AC ratio of 1.5 is built until 2028, after which half as much solar PV with DC/AC ratio of 1.7 is built.

Similar to Scenario 1 and 2 above, the battery technology picked is all lithium-ion with 3 and 4-hours duration storage with 3-hour battery (50 MW) being built in 2023 only.

CSP technology is identical to Scenario 2 but the early units are delayed by one year with 15-hour duration storage is built in 2025 and 2030, and one with 12-hour storage is built in 2026.

We note that all three scenarios rely heavily on BESSs with an aggressive build-out early on during the horizon. Indeed, BESS with its modularity and short lead times is one of the quickest technologies to deploy.

BESS is used for a number of purposes in Barbados:

- Daily shifting of solar PV generation from midday periods into the evening peak
- Primary and Secondary Reserve Provision
- Provision of flexibility for balancing and smoothing variable renewable output

By 2023, a number of significant changes to the system will already be under way:

- Significant amount of generation capacity will already need to be retired (Steam Plant 1 & 2)
- Increasing VRE deployment increases supply balancing requirements
- Primary reserve provision is expected to shift away from the UFLS and be provided by other supply options
- Secondary reserve provision requirements will grow as VRE supply on the systems grows

These are the drivers behind the deployment of battery storage. There may however be a risk that the level of deployment suggested by the IRRP is not achieved in the given timelines, particularly by 2024. We have therefore explored the impact of a delays or phasing of this deployment over several years as well which is discussed in more detail in section 7.2.2.8 below.

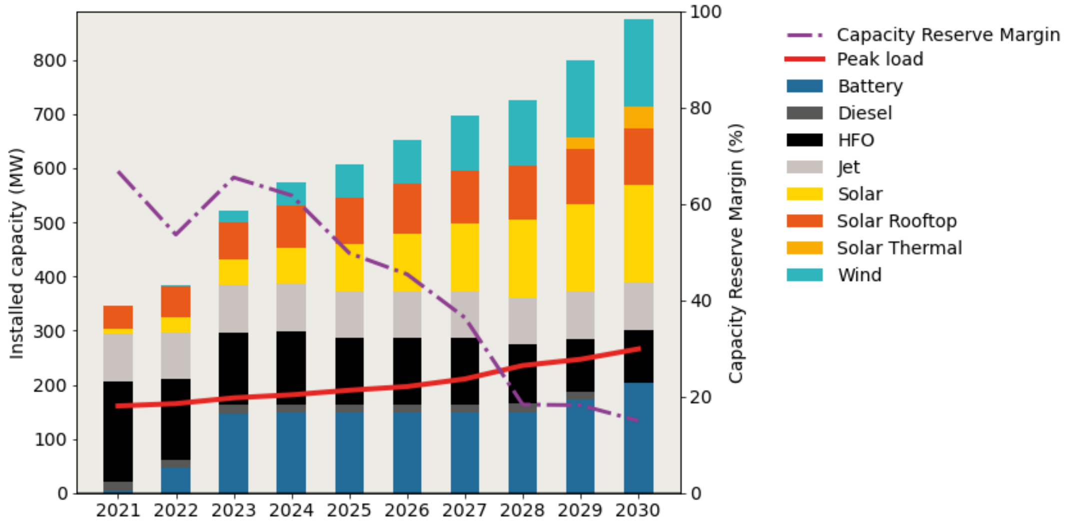
7.2.2.2 Installed capacity and peak load

In terms of the evolution of the system, the figures below show the total capacity installed for each scenario over the planning horizon. The installed capacity [in MW] and peak load [MW] are displayed against the capacity reserve margin (CRM) [in %]. Please note that the CRM is calculated using the firm capacity rather than the installed capacity, i.e., is corrected for its dependable firm generation in relation to meeting peak demand.

All scenarios (including the least-cost scenario that treats the cost of carbon emissions as an externality) stand out for the projected growth in VRE capacity and batteries such that installed capacity reaches over 800 MW by 2030, or four times the peak demand. Given the lower capacity factors of renewable energy averaging about 25%, this observation can easily be explained.

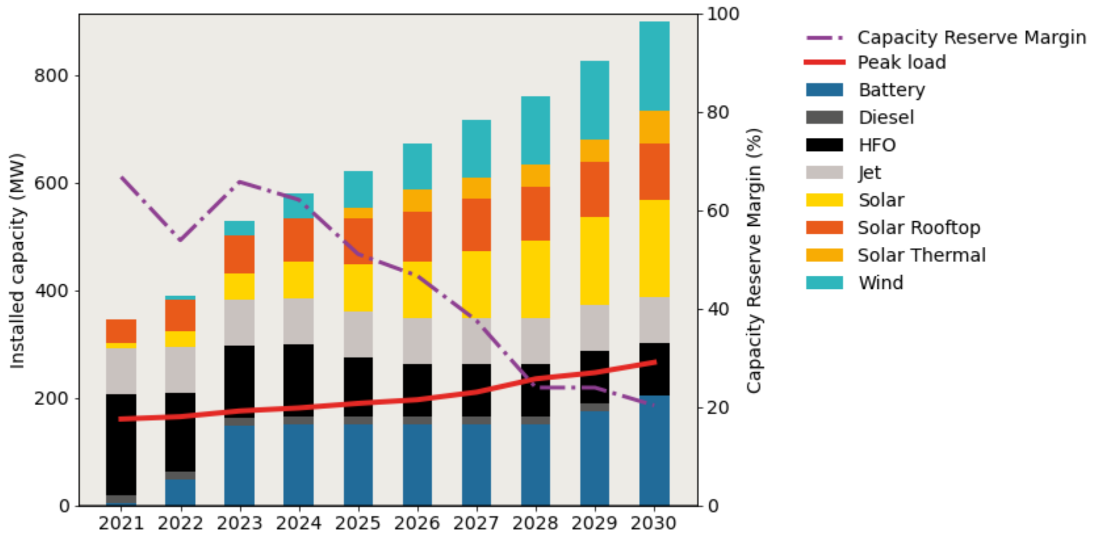
This is also the reason why for the CRM, only firm capacity is considered. The CRM is shown on a generally declining trend, falling from about 40% today to 15% in 2030. We see later that this does not impair system reliability. The reliability is not impacted with reduced capacity reserve margin as the demand forecast assumes an increased portion of dispatchable load as the planning horizon progresses. Conversely at the start of the planning horizon the load is non dispatchable and a small portion of BESS is required to help with peak shaving. The future generation mix includes renewables, BESS and dispatchable load which all contribute to load management and peak shaving and therefore does not impact the reliability of the system. Furthermore, the simulated system reliability is inclusive of forced outages and maintenance of generation assets.

Figure 7.10: Scenario 1 – Installed capacity mix and peak load



Source: Mott MacDonald

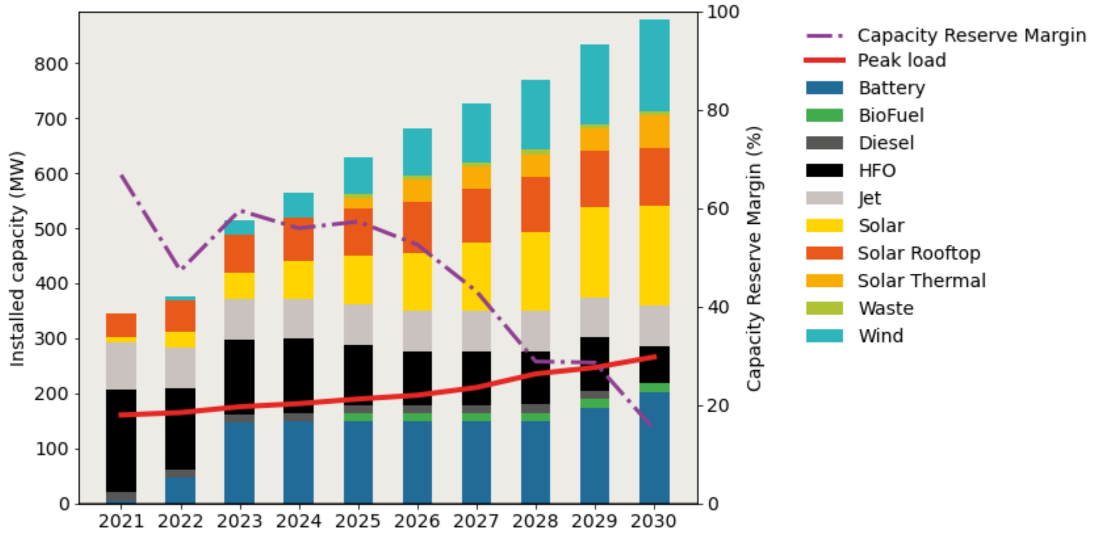
Figure 7.11: Scenario 2 – Installed capacity mix and peak load



Source: Mott MacDonald

The capacity mix for Scenario 2 is very similar Scenario 1, with a higher level of solar thermal and also an earlier introduction (2025 versus 2029); this substitutes for HFO capacity which is retired earlier in Scenario 2 than in 1.

Figure 7.12: Scenario 3 – Installed capacity mix and peak load



Source: Mott MacDonald

Scenario 3 is similar to Scenario 2 with the exception of biofuel and waste replacing HFO plant.

7.2.2.3 Annual costs

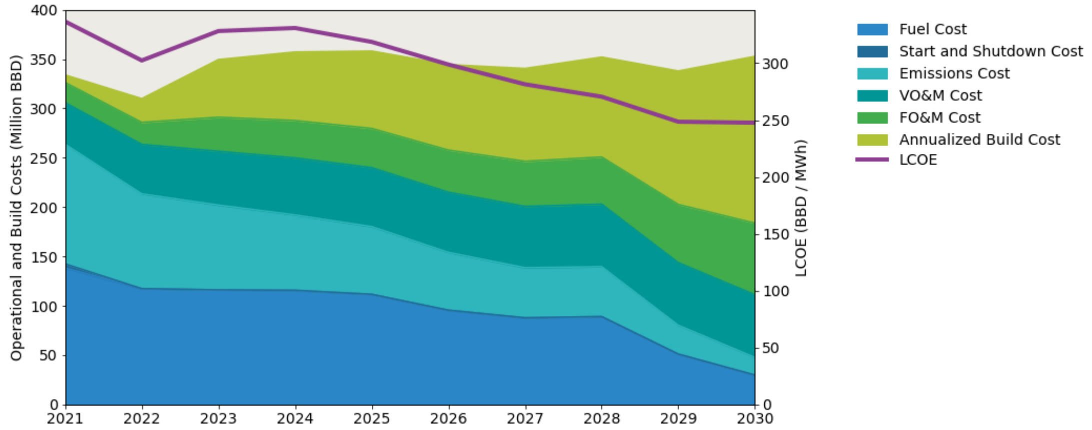
Figure 7.13 shows the evolution of total costs in Scenario 1 planning horizon. All cost categories include the cost for generators, batteries, and synchronous condensers. Other transmission assets are excluded in this analysis. Note that the LCOE is a simplified LCOE that simply divides the total cost (cost categories shown in the figures below) by the total generation in each year. The LCOE is a good approximation of the generation tariff although it excludes additional cost of service such as depreciation and overheads such as cost of the transmission and distribution business.

As expected, the fuel and variable cost of the system decrease rapidly over the horizon as renewable plants are built and fossil fuels plants retire. This is however substituted for by a large increase in build[5] costs to add the renewable energy assets into the capacity mix, which becomes the largest cost component required for the system. In contrast, the fuel cost which is now the largest cost component becomes an insignificant share of the cost over time.

The LCOE decreases from its 2021 level of 336 BBD/MWh in all three scenarios. Scenario 1 achieves a 27% reduction over the horizon to 247.65 BBD/MWh the highest cost savings. Although, the LCOE decreases in most years and steadily from 2024, there is an increase between 2022 and 2024 which is a result of significant capacity being added in that period.

[5]Build costs are presented as Annualized Build Cost which can be thought of as mortgage payments for the capital assets

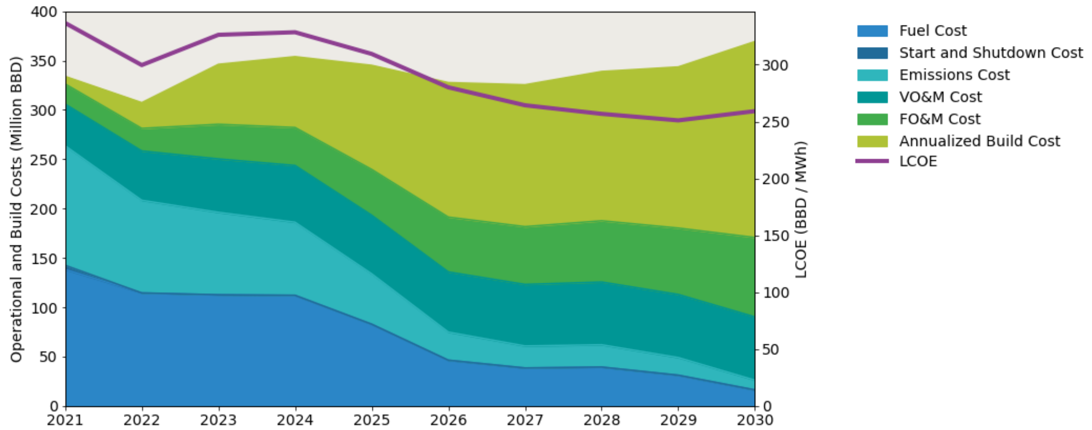
Figure 7.13: Scenario 1 – Total costs



Source: Mott MacDonald

Scenario 2, shown by Figure 7.14 has a higher build cost than Scenario 1 due to the addition of 20 MW of CSP. This results in a steeper decrease of fuel and emissions cost, driven by the carbon price in the model compared to Scenario 1. The LCOE in Scenario 2 is slightly higher than Scenario 1 however still decreases to approximately 260 BBD/MWh.

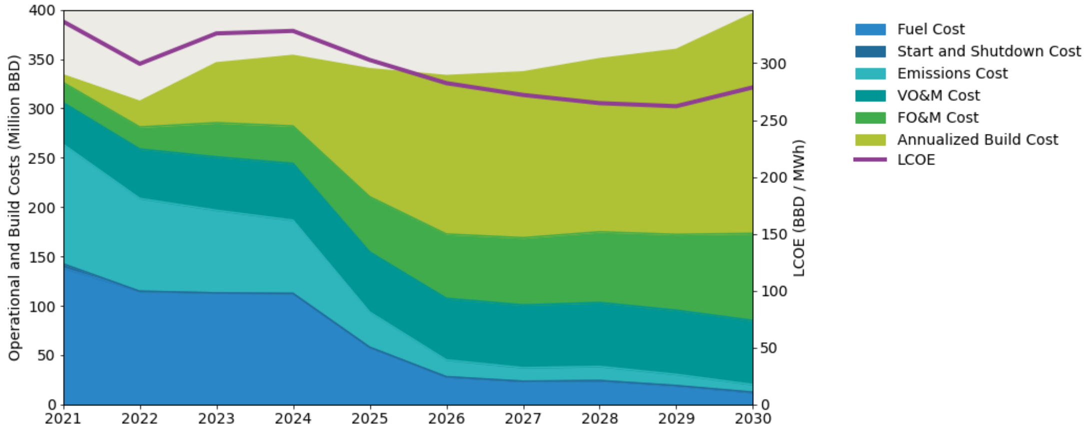
Figure 7.14: Scenario 2 – Total costs



Source: Mott MacDonald

Figure 7.15 shows Scenario 3 as being similar to Scenario 2 but with a higher LCOE and Total Cost as a result of the build of expensive waste and biofuel power plants. The LCOE by 2030 is approximately 280 BBD/MWh. The VO&M and FO&M also increase slightly due to the waste and biofuel plants. Table 7.4 presents a summary of the undiscounted build costs in each of the three scenarios.

Figure 7.15: Scenario 3 – Total costs



Source: Mott MacDonald

Table 7.4: Undiscounted build costs (million BBD) in the three scenarios

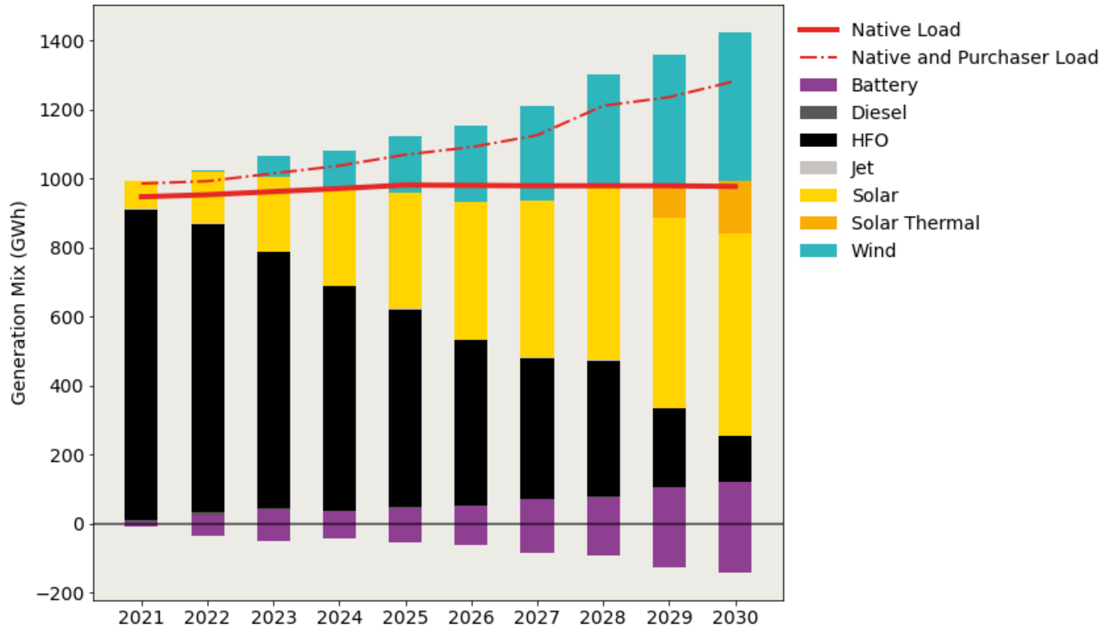
Year	Scenario 1	Scenario 2	Scenario 3
2021	117.37	117.37	117.37
2022	145.18	170.35	168.72
2023	311.29	314.43	314.42
2024	131.58	131.24	129.93
2025	110.96	419.86	747.56
2026	100.88	384.31	384.02
2027	92.67	92.67	92.67
2028	88.84	92.17	91.71
2029	400.57	125.47	125.63
2030	395.93	417.45	418.03

7.2.2.4 Generation mix

Figure 7.16 below shows the generation mix compared to the native and system load for each year [in GWh]. Native load refers to the normal electricity demand within Barbados. Purchaser load refers new demand sectors of demand that is expected to gradually electrify, such as EV and cruise liner demand. The dotted red line (native and purchaser load) shows the total demand in the Barbados system that needs to be met. Note that the sum of generation has to be in excess of loads in order to charge the batteries as well as to cover the charging losses (which are represented as negative generation in the battery category).

Generation in 2021 consists mostly (91%) of fossil fuel plants and the remainder from solar PV (rooftop – 6% and ground mounted – 2%) and BESS (1%). However, the ratio of fossil fuel to renewables generation rapidly inverts, even in Scenario 1 (see Figure 7.16 below) and by 2030 to only 9% of generation is from liquid fossil fuels, 41% from solar PV (ground mounted and rooftop), 11% from CSP and 30% from onshore wind. Battery generation is equivalent to 9% however that it not a net contribution since battery storage has a negative net generation due to charging losses.

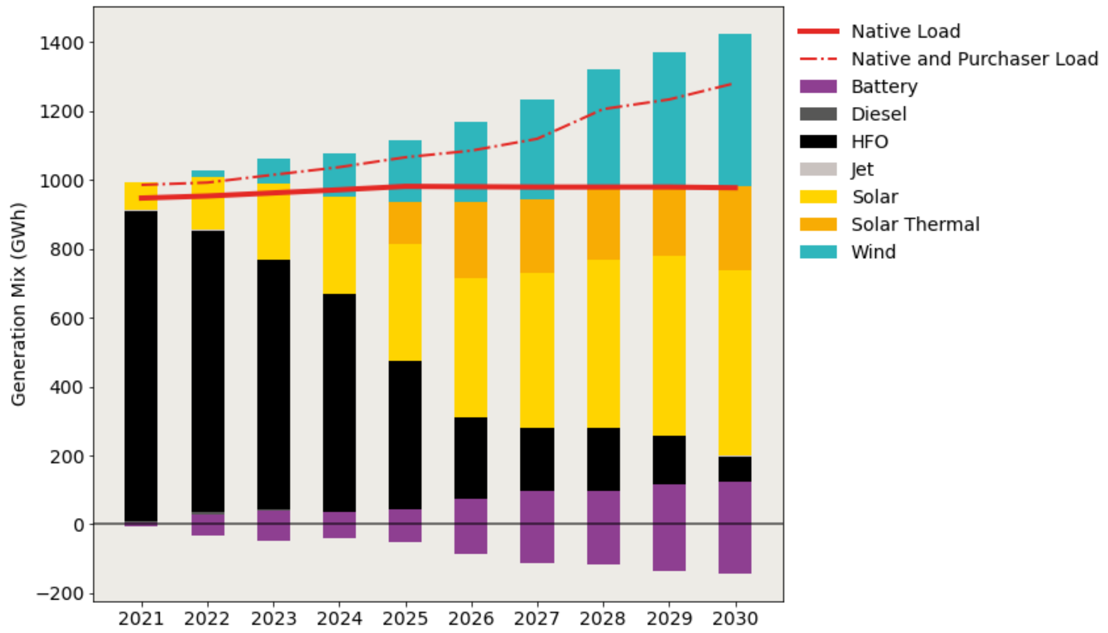
Figure 7.16: Scenario 1 – Generation mix



Source: Mott MacDonald

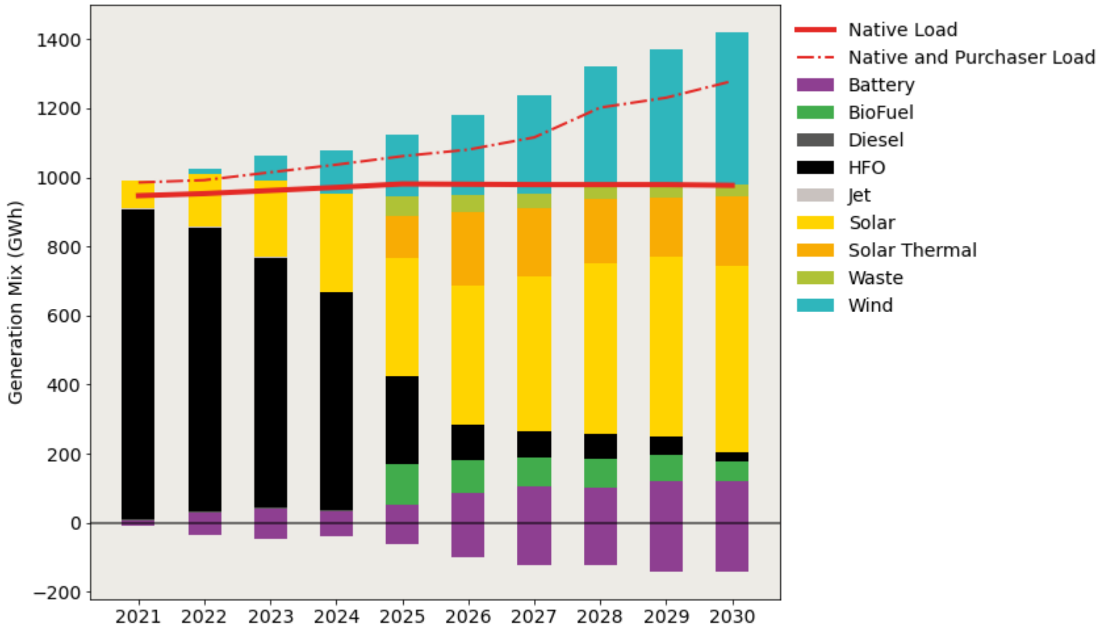
The generation mix for Scenario 2 is shown by Figure 7.17, due to the more rapid uptake of renewables in this Scenario, the generation mix shifts even the 2030 generation mix is only 5% fossil fuels, 31% wind, 38% solar PV, 17% CSP, and 9% BESS. Fossil fuel generation is 4% less in this scenario than Scenario 1 due to additional CSP capacity.

Figure 7.17: Scenario 2 – Generation mix



Source: Mott MacDonald

Figure 7.18: Scenario 3 – Generation mix



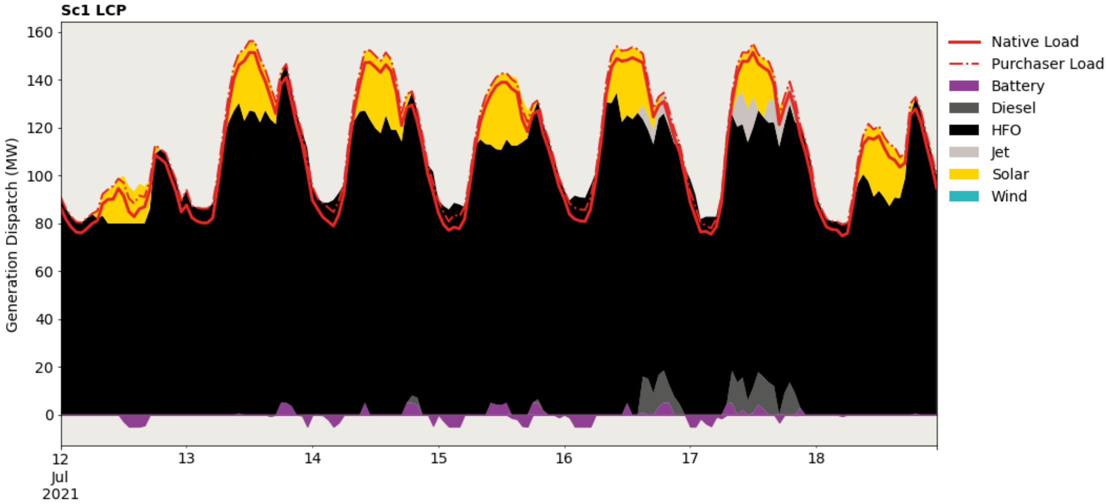
Source: Mott MacDonald

Figure 7.18 above shows the generation mix for Scenario 3 which is slightly different due to the introduction of waste and biofuel plants from 2025. Therefore in 2025 there is a more significant drop of the share of generation from fossil fuels. By 2030 the generation mix is 2% fossil fuels, 4 % firm renewables (waste – 1%, biodiesel – 3%), 31% wind, 38% solar PV, 14% CSP, and 9% BESS. Fossil fuel generation is 7% less than Scenario 1 and 3% less than Scenario 2.

7.2.2.5 Typical week dispatch

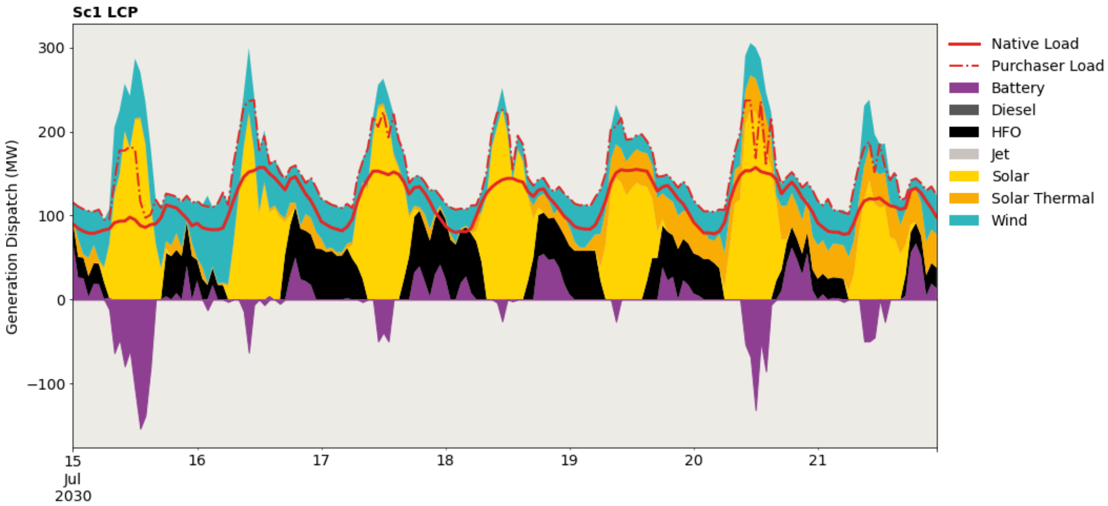
The pattern of dispatch is set to change dramatically during the next decade under all the scenarios as variable renewable generation meets an increasing share of generation and surpluses are partly absorbed in batteries which are discharged during the evening peak. The following charts show an eight-day snapshot of dispatch in 2030 (compared to the 2021 baseline Figure 7.19 below) for all scenarios.

Figure 7.19: Scenario 1 – 2021 typical week dispatch



Source: Mott MacDonald

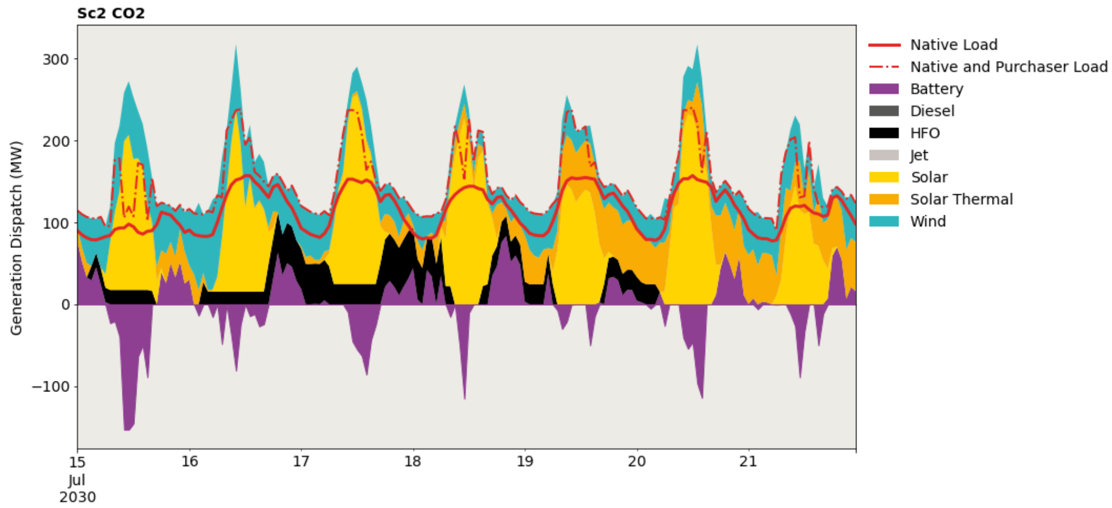
Figure 7.20: Scenario 1 – 2030 typical week dispatch



Source: Mott MacDonald

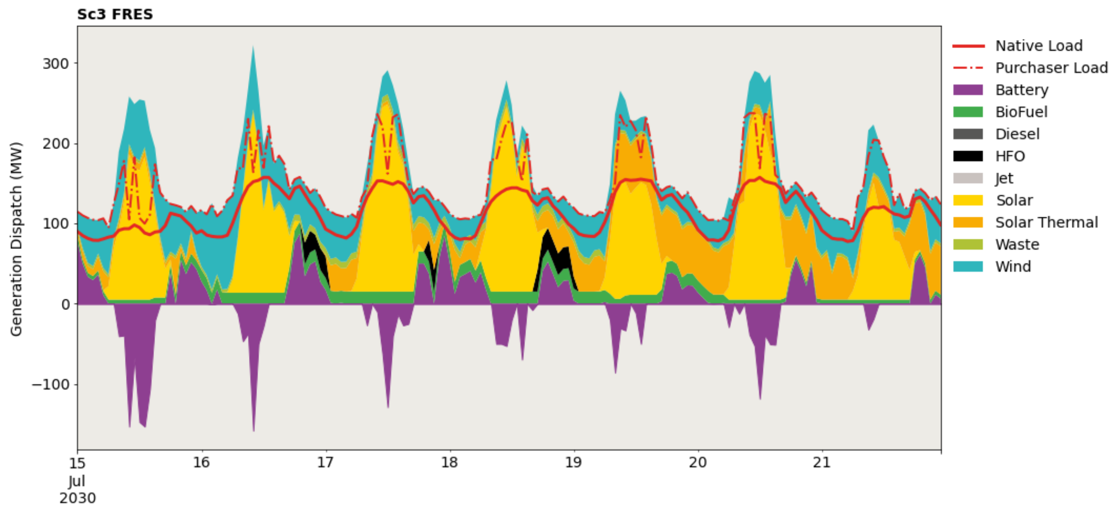
Although not always visible, synchronous generation is available every hour during the year from firm generation plants. In Figure 7.20 above, there are specific hours where synchronous generation reaches its lowest figures, however during these hours there is a minimum amount of CSP generation.

Figure 7.21: Scenario 2 – 2030 typical week dispatch



Source: Mott MacDonald

Figure 7.22: Scenario 3 – 2030 typical week dispatch



Source: Mott MacDonald

The key observations to note are as follows:

- The power system will become much harder to operate in future as VRE share increases and as the system operator will need to depend on effectively managing non-dispatchable resources. The ability to forecast expected renewable resource generation ahead of time will be important to ensure balancing resources are committed and, in the case of storage, the state of charge is effectively managed.
- Solar PV generates in the middle of the day and tends to have a surplus over demand which is used to charge batteries. The charts exclude VRE curtailment, which is material by 2030 on sunny and windy days.

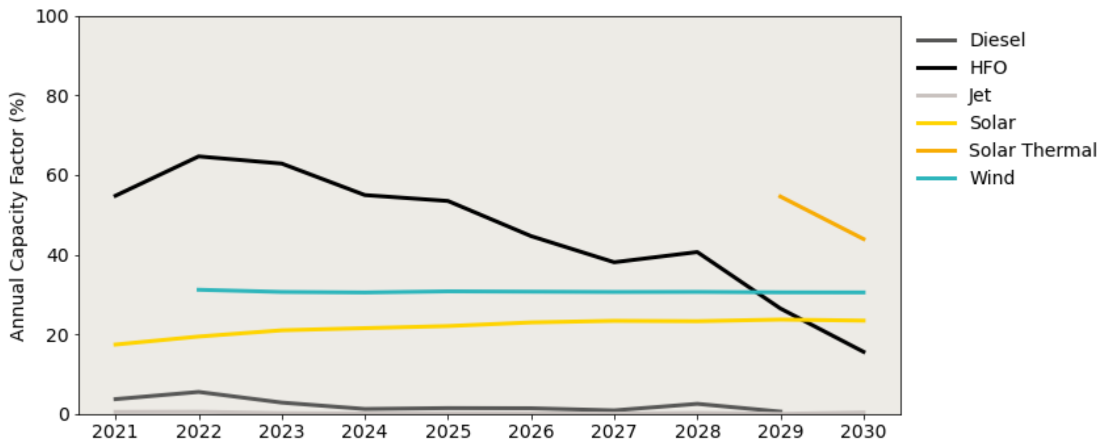
- A significant number of batteries will be charged during the day from solar PV generation to shift output into the evening and night. This is in contrast to the small amount of battery storage currently present in the Barbados system. At present, the battery charges at night when cost and demand is low.
- Wind generation is much more volatile than solar PV but tends to generate slightly more at night compared to daytime generation. Also, windy periods are more likely associated with cloud movement, therefore wind and solar PV output are not correlated.

HFO generation (Resiliency Bridge) is filling in the renewable energy gaps, so is particularly important in the evening peak and night times still, although in much smaller quantities than at present. Scenario 3 relies the least on HFO plant because Biofuel and Waste plant can provide a level of dispatchable back-up generation although that does not completely remove the need for fast and flexible HFO engines (see Figure 7.22 below). Scenario 2 also uses less HFO generation than Scenario 1 with more CSP generation being available (compare Figure 7.20 and Figure 7.21 below).

7.2.2.6 Capacity factors

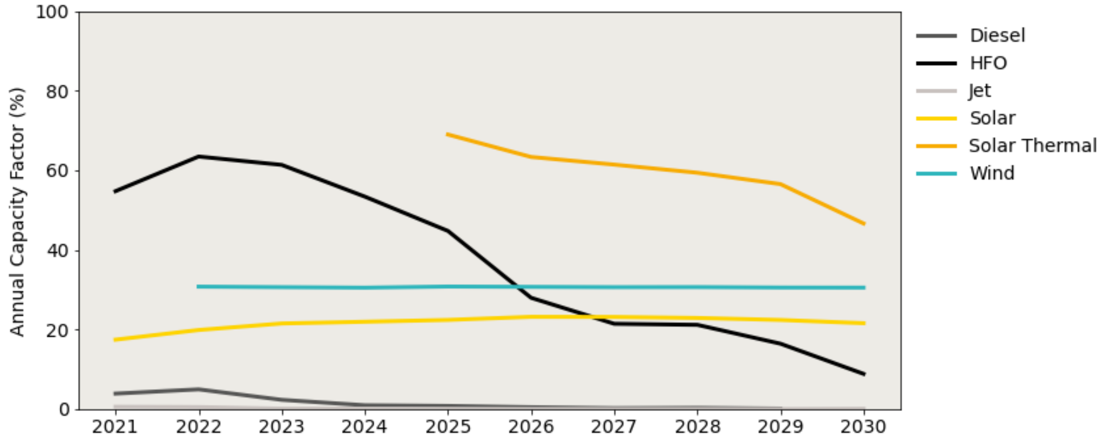
Annual Capacity Factors [ACF] by fuel type are shown in the following figures. With the additions of renewable generation, the fossil fuel plant ACFs decrease. Solar thermal ACF decreases due to another CSP build an in 2030. These ACFs are net of curtailment as they are measured on the basis of generation rather than availability.

Figure 7.23: Scenario 1 – Annual capacity factors



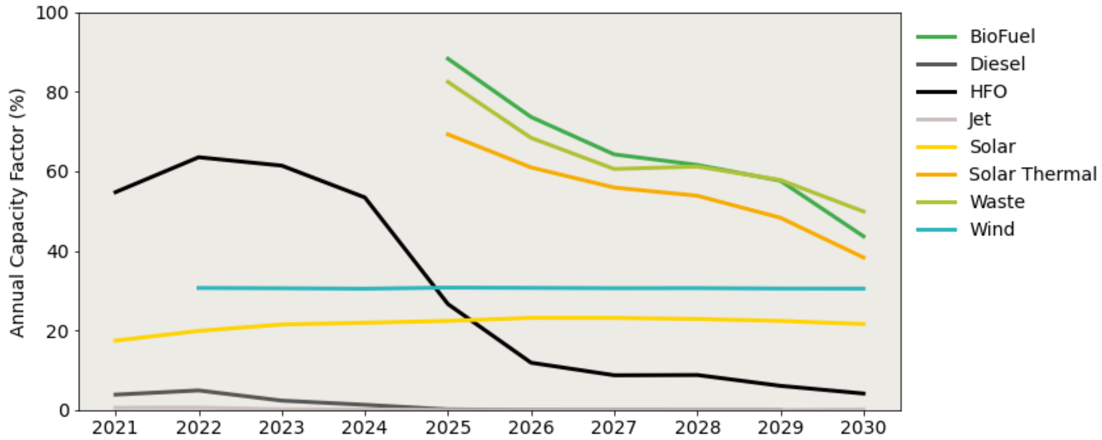
Mott MacDonald

Figure 7.24: Scenario 2 – Annual capacity factors



Source: Mott MacDonald

Figure 7.25: Scenario 3 – Annual capacity factors



Source: Mott MacDonald

Across all scenarios, the fleet of HFO plant sees the ACF fall from 50% to below 10% over time. Scenario 2 and scenario 3 achieve a faster and reduction in the ACF of HFO plant where ACF are ultimately below 4% and 1%, respectively.

Diesel and Jet Fuel plant (GTs) see no real change in ACF which is because they are already only being used as peaking or back-up plant, a function that the machines that are being kept in service will still have to perform in future. Scenario 3 allows earlier retirement of such plant.

Solar PV and wind have broadly flat ACFs at 20% and 30%, respectively. The Solar ACF increases however over time as the composition of the PV plant fleet changes from being largely roof-top based (which are often not optimally placed with respect to maximising energy due to shade-free roof space and sun-angle limitations) to having a high share utility-scale PV plants with high AC/DC ratios which provide more energy for a given AC capacity. Solar Thermal, or CSP has a higher ACF than PV because of the thermal storage being utilised to drive a steam turbine. Larger storages in conjunction with larger collector fields for a given steam turbine size allows for operation at higher ACFs.

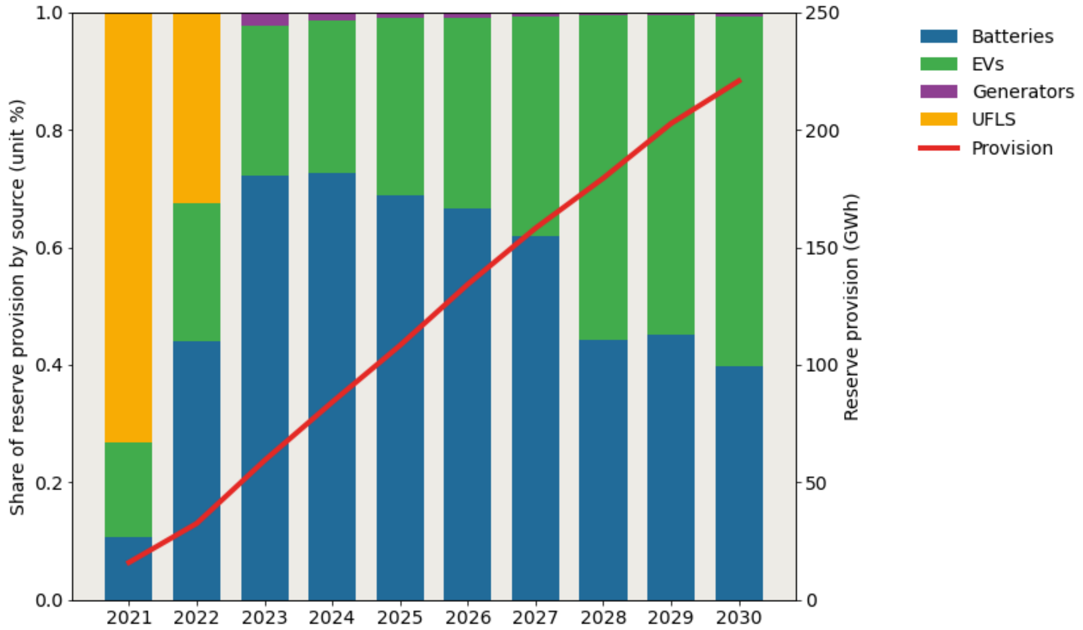
Scenario 3 differs from Scenario 2 with the inclusion of waste and biofuels power plants and with the capacity factor of HFO dropping to zero. The reason for the reduction in the capacity factor of waste and biofuel from 2025 to 2030 is due to the increased level of solar and the introduction of solar thermal power plant. The dispatchable waste and biofuels power plants are still important for secondary reserves and mid-merit operation.

7.2.2.7 Secondary reserve provision

The secondary reserve figure for Scenario 1 (Figure 7.26) is instructive as it shows the requirement for UFLS reducing to zero by 2023 and EV smart charging functionality complementing utility scale BESS for secondary reserve provision by 2030. Very little secondary reserve is supplied from thermal generators given the efficiency penalty and additional cost of fuel that it requires.

The secondary reserve provision increases throughout the planning horizon as a function of the increasing level of variable renewable energy penetration in the system

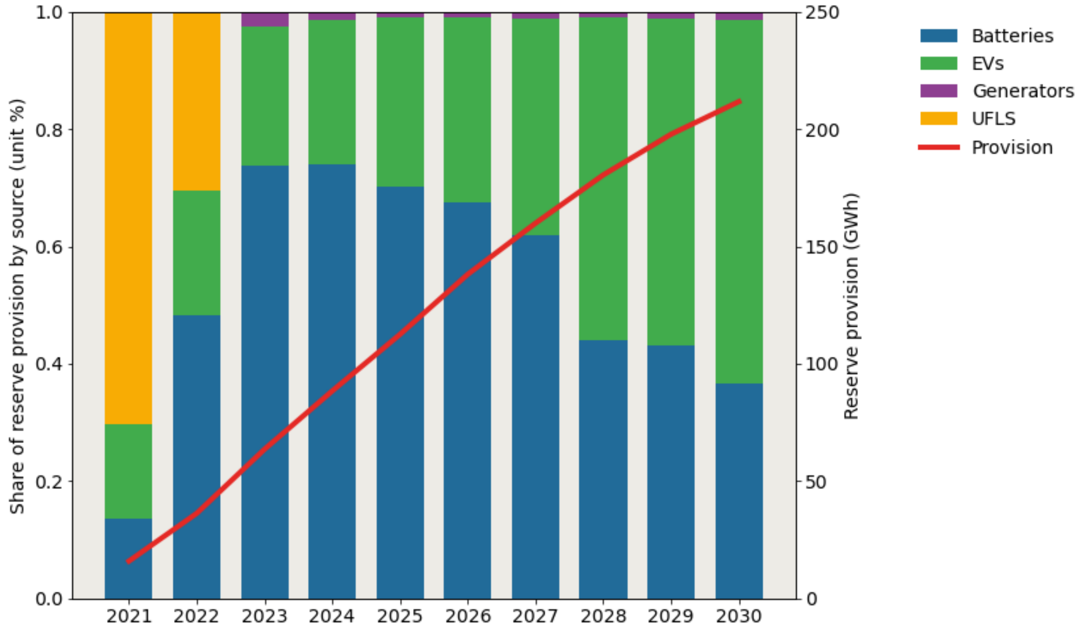
Figure 7.26: Scenario 1 – Secondary reserve provision by source



Source: Mott MacDonald

Figure 7.27 shows the secondary reserve provision for Scenario 2 as being similar to Scenario 1.

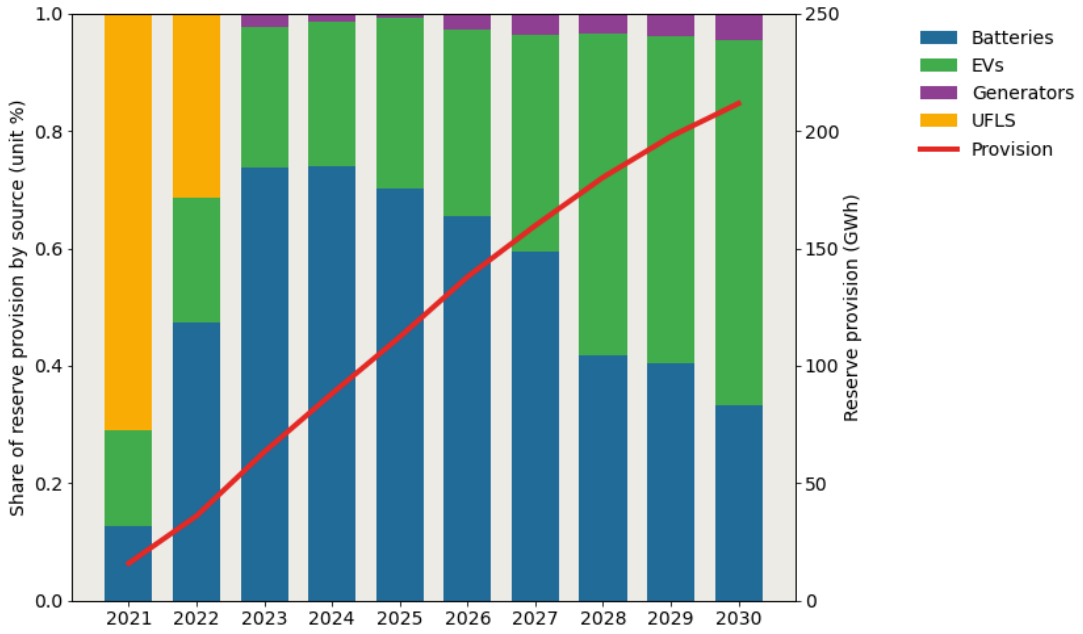
Figure 7.27: Scenario 2 – Secondary reserve provision by source



Source: <Insert Notes or Source>

The secondary reserve provision for Scenario 3 (Figure 7.28) differs from Scenario 1 and Scenario 2 with the inclusion of biofuels and waste synchronous generation plant leading to a slightly higher share of reserves being provided from thermal generators; these predominately would be low cost-fuel generators.

Figure 7.28: Scenario 3 – Secondary reserve provision by source



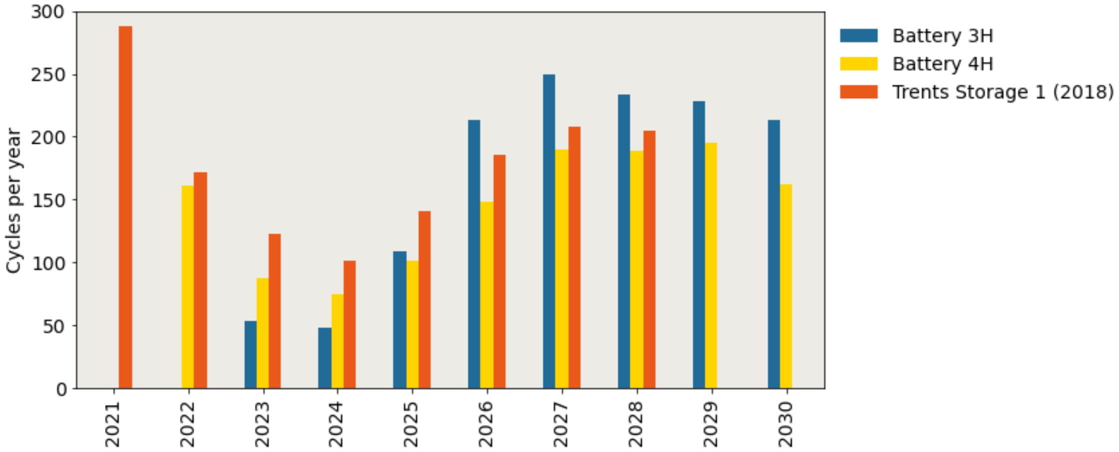
Source: Mott MacDonald

7.2.2.8 BESS Deployment Delay Risks

Although possible to deploy sufficient BESS to meet the plans, there may be a risk that the level of deployment suggested by the IRRP is not achieved in the given timelines, particularly by 2024. We have therefore explored the impact of delays or phasing of this deployment over several years.

As seen in section 7.2.1.4 above, the reliability of the system improves rapidly from current levels at the margin of what is required to about five hours of LOLE in 2023 and 2024. The installed BESSs are also shown to perform fewer cycles (see Figure 7.29 below) than the 365 cycles they would conservatively be able to perform each year given the assumed lifetime (scenario 2 cycles are similar). Note however that the cycling accounts only for energy shifting and not for any cycling during response to frequency excursions during reserve provision. In practice, also the UFLS utilisation (see section 7.2.2.7 above) could continue beyond 2022.

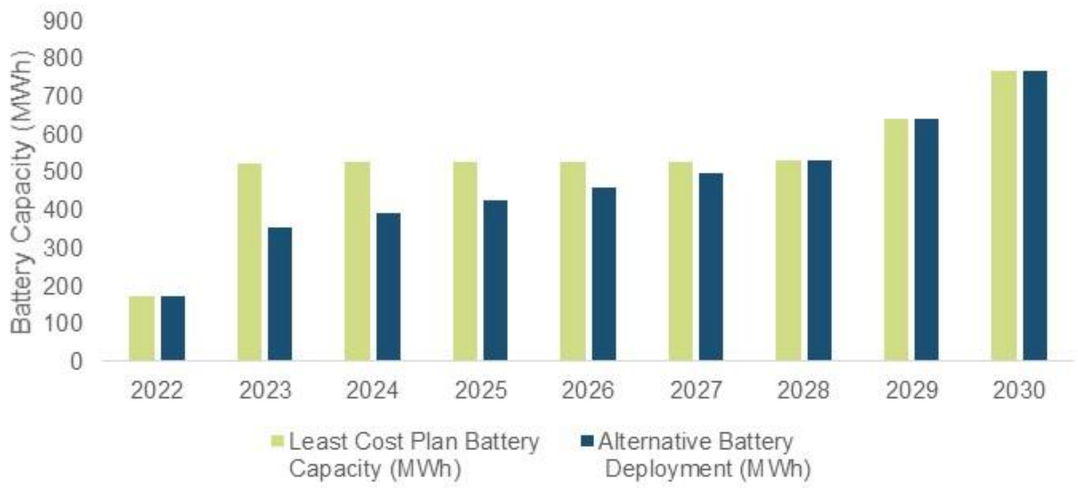
Figure 7.29: BESS Cycling (Scenario 3)



Source: Mott MacDonald

In theory therefore, a delay would not be expected to cause significant issues and is not a significant risk. To test the impact of a more gradual phasing of BESS deployment, we have assumed that only 2/3 of the battery capacity is installed initially in 2023, with constant yearly additions that reach the optimal level of battery capacity by 2028 as suggested by the IRRP results.

Figure 7.30: Battery Capacity Deployment Alternatives



Source: Mott MacDonald

The results show that the reliability of the system does not see a material impact, however there is an 11.4% increase of total system cost over the horizon of the system in NPV terms. This divergence from the least-cost solution would raise the tariffs as can be observed in Figure 7.31 where the LCOE is higher for all years of the horizon.

Figure 7.31: Levelised Cost of Energy Comparison

Source: Mott MacDonald

The results indicate therefore that it is not detrimental to system reliability if the BESS is delayed, however it is sub-optimal from a cost point, although still not carrying a large penalty. The risks from a potential delay in the deployment of BESS are therefore low.

It is also worth noting that the cycling of the BESS in the delayed scenario does not significantly change, which confirms that the dispatch of the BESS is driven by the need to provide flexibility to balance the system rather than for bulk energy shifting. Further, the need for increasing secondary reserve provision is a large driver for BESS in Barbados as it is elsewhere. Noting this and the existing caveats around the secondary reserve dimensioning in Barbados (refer to discussion in Appendix section G.1.2.5 and analysis in Appendix section G.3), we propose that this will need to be further studied and also be reviewed on the basis of operational experience in Barbados as the IRRP is being implemented.

7.2.3 Sensitivity analysis

We present in this section the results of a typical sensitivity analysis; however, rather than quantifying the impact of a set percentage change in an input variable on NPV, these sensitivities are better thought of as scenarios of what conceivable high or low case for the respective input variables could look like.

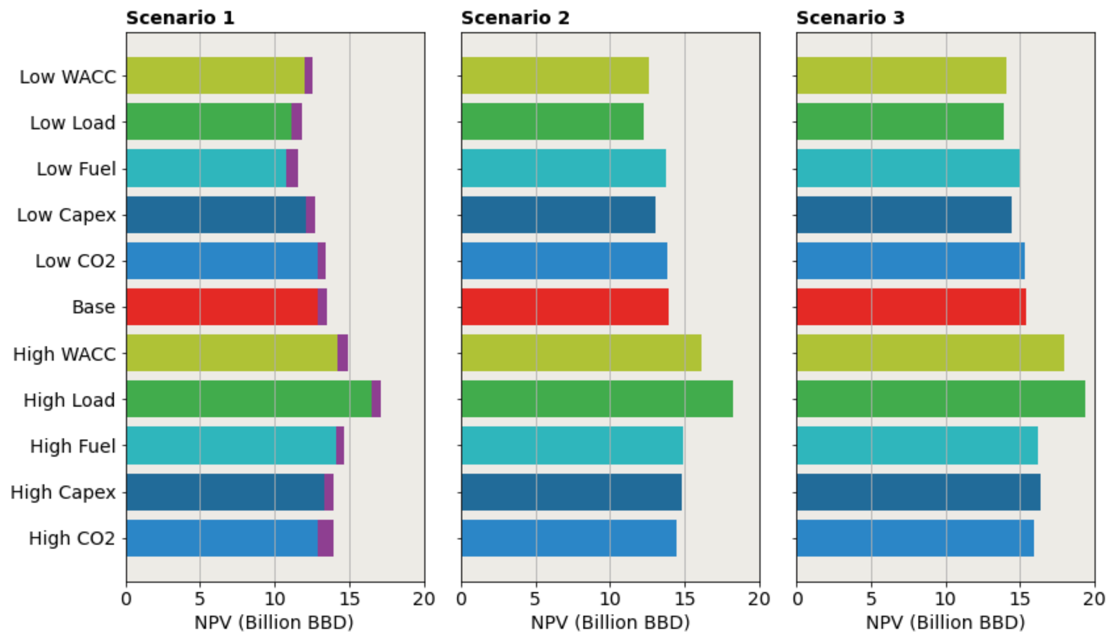
We analysed the sensitivity of each of the three base scenarios by fluctuating the following variables: capex, WACC, load, fuel price, and carbon price and assessing the impact on NPV, carbon emissions, and planting decisions. As Scenario 1 carbon costs are externalised, we have adjusted the NPV to include the cost of carbon emissions (indicated in purple).

7.2.3.1 NPV

Figure 7.32 below shows the highest increase in cost would come from a high load growth (29%, 31%, and 26% increase from their base scenario for Scenario 1, 2, and 3 respectively). This growth in demand would require a ramped-up level of operation and increased investment in generation assets throughout the horizon. As capital costs are the most significant, the models affect from this sensitivity variable is to be expected.

The largest reduction in NPV comes from the low fuel price for Scenario 1 (-14%) and low load growth for Scenarios 2 (-12%) and 3 (-10%). In terms of Scenario 1, the sensitivity of the fuel price could be attributed to the existing liquid fossil fuel plants operating for a longer period of time. Conversely, Scenario 2 and 3 do not benefit as much from lower fuel prices due to the carbon price being in effect. However, if the load growth is lower than the base scenario, the overall costs are reduced.

Figure 7.32: All scenarios - NPV comparison

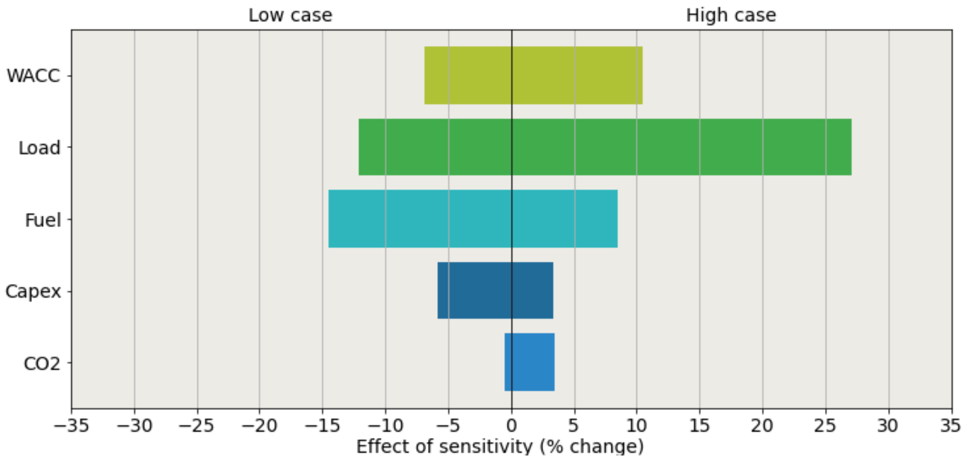


– Cost of Carbon Emissions

Source: Mott MacDonald

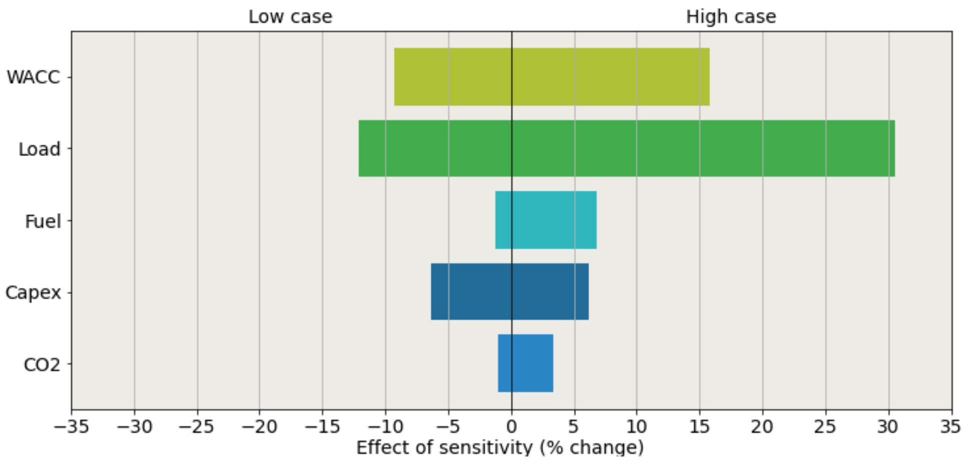
Detailed comparison of each scenario to is shown in Figure 7.33 to Figure 7.35 below. These clearly indicate the most and least sensitive scenarios.

Figure 7.33: Scenario 1 NPV sensitivity



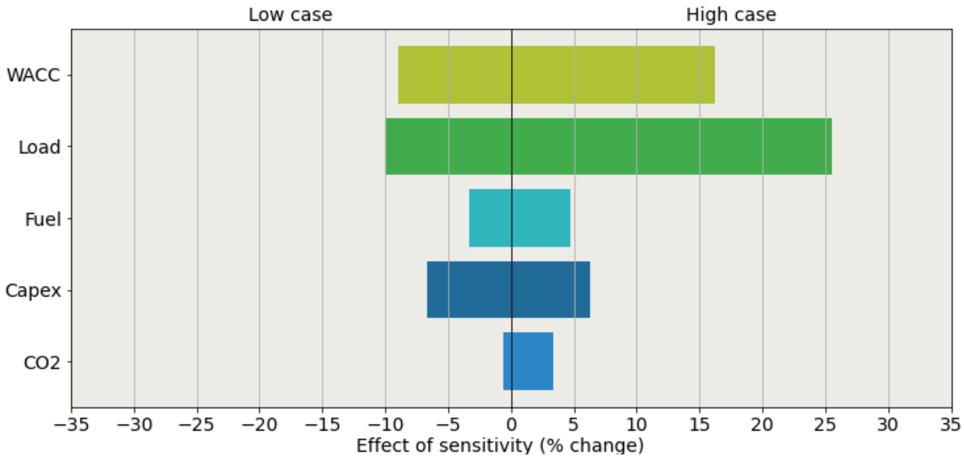
Source: Mott MacDonald

Figure 7.34: Scenario 2 NPV sensitivity



Source: Mott MacDonald

Figure 7.35: Scenario 3 NPV sensitivity

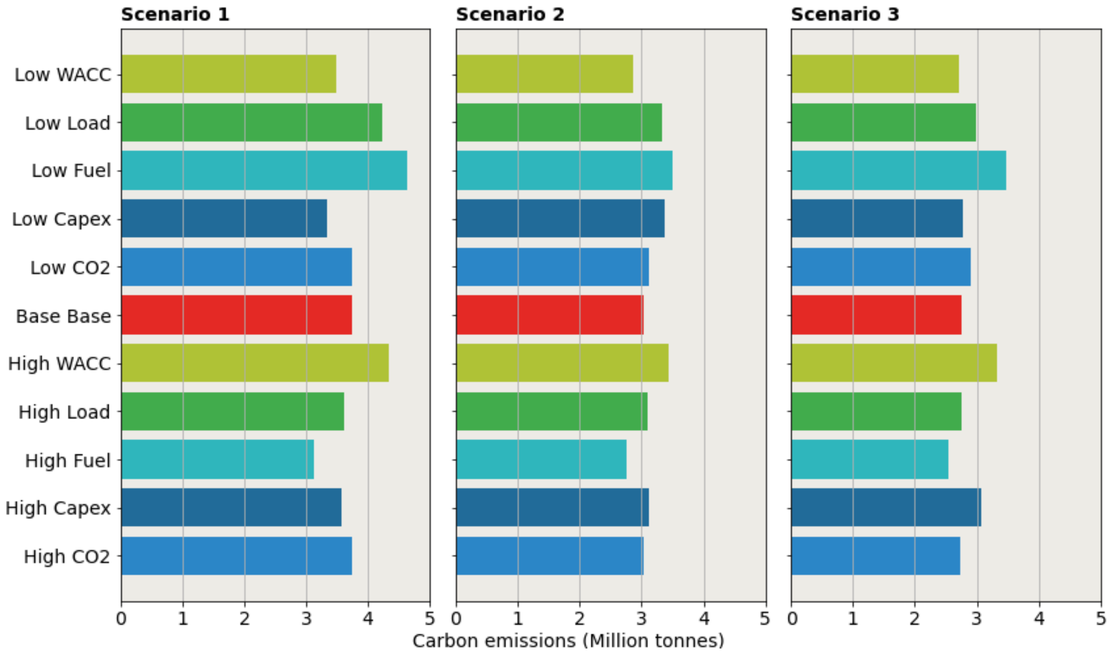


Source: Mott MacDonald

7.2.3.2 Carbon Emissions

Figure 7.36 below shows the cumulative carbon emissions over the planning horizon for each scenario and sensitivity. In all three scenarios low fuel sensitivity and high WACC correlate to the most carbon emissions. This is expected as low fuel price incentivises the system to keep existing thermal plants in operation. The higher WACC results in the model less likely to build more renewables as this would incur a higher capital cost than usual. In all scenarios the low load sensitivity has higher carbon emissions than the high load sensitivity. This is due to the base and low load demand assuming 50% smart charging and 50% fixed charging profile for electric vehicles, while the high demand profile assumes 100% smart charging for electric vehicles. In the high load case as EV load is dispatchable, the system is better balanced and more EVs can be charged during periods of high renewable generation hence decreasing emissions The NPV and level of carbon emissions can be further explained when comparing the capacity additions and retirements in section 7.2.3.3 below.

Figure 7.36: Total carbon emissions

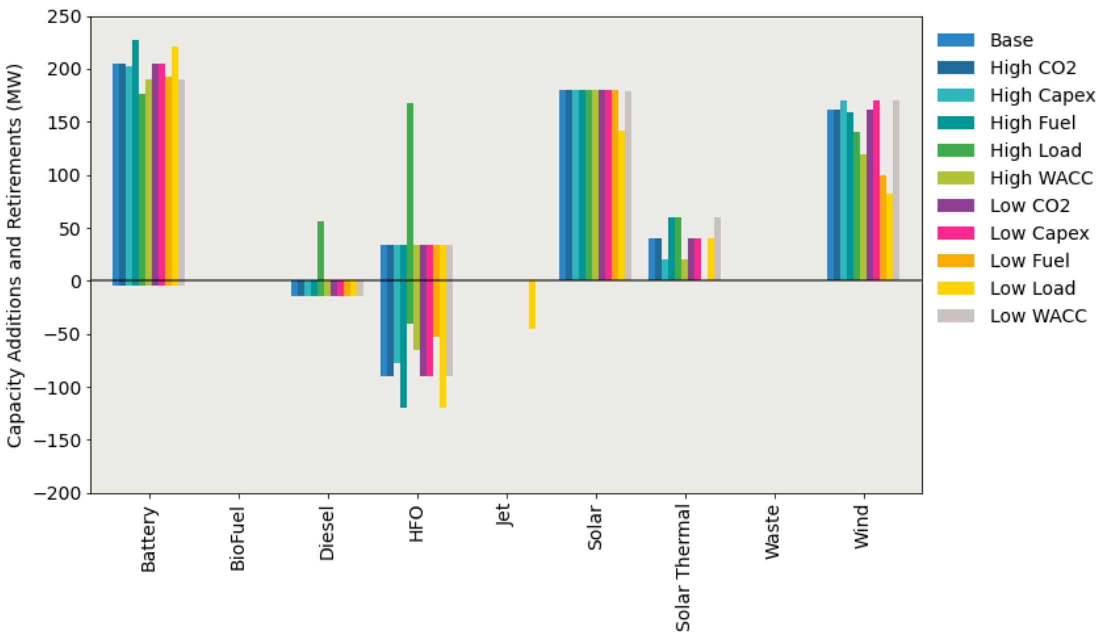


Source: Mott MacDonald

7.2.3.3 Capacity additions and retirements sensitivity

The subsequent figures below show the sensitivity of the builds and retirements in the system compared to their respective base cases. This allows us to know the type of generation or retirement that is robust and likely to remain the same of similar despite real-world factors.

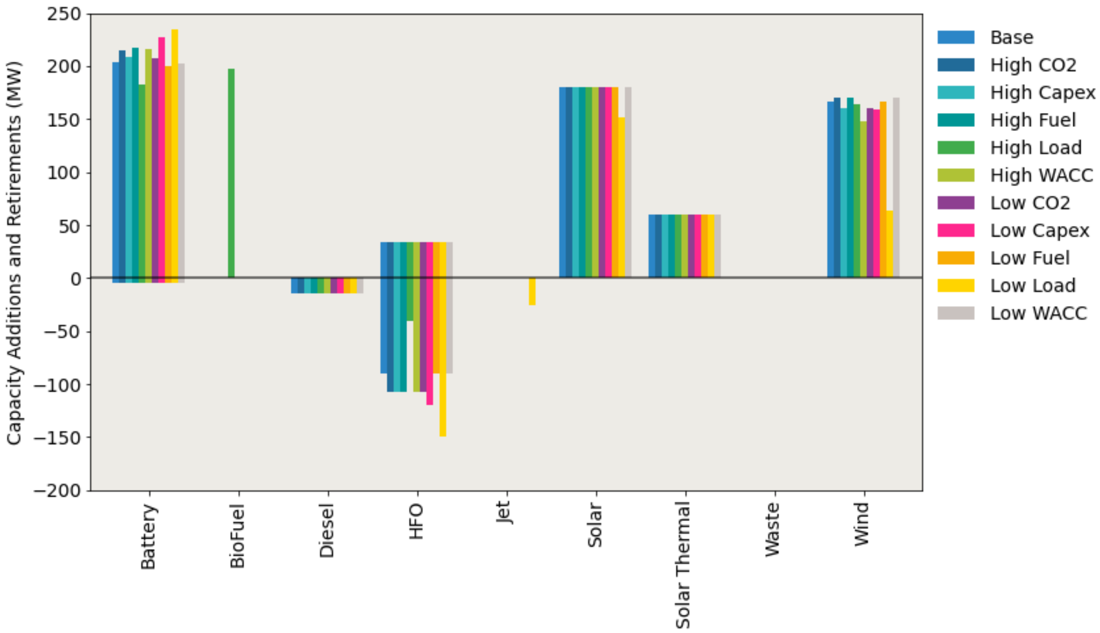
Figure 7.37: Scenario 1 sensitivities capacity additions and retirements



Source: Mott MacDonald

Figure 7.37 above shows HFO retirements, solar thermal and wind as being the most sensitive to the variables tested. Battery capacities remain around 200 MW, building 50 MW of the 3-hour battery in every scenario and the remaining capacity always filled by the 4-hour battery. Diesel and HFO builds are robust, however in the high load case, an additional OCGT plant (diesel) and a few MSD units are built to accommodate high system load. Solar (ground-mounted PV) capacity additions are also robust with the only scenario influencing a difference in built capacity is the low load scenario where it appears that the system load is low enough to justify the retirements of HFO and jet fuel units in addition to building less wind capacity. A noteworthy scenario is the low fuel scenario; this is the only scenario that does not build any solar thermal plants yet retires a significant number of HFO units. This results in the system having a lower capacity of firm generation; therefore, these existing units operate at a higher capacity factor, burning more fuel (as it is economical to do so) and consequently emitting the highest carbon emissions comparatively.

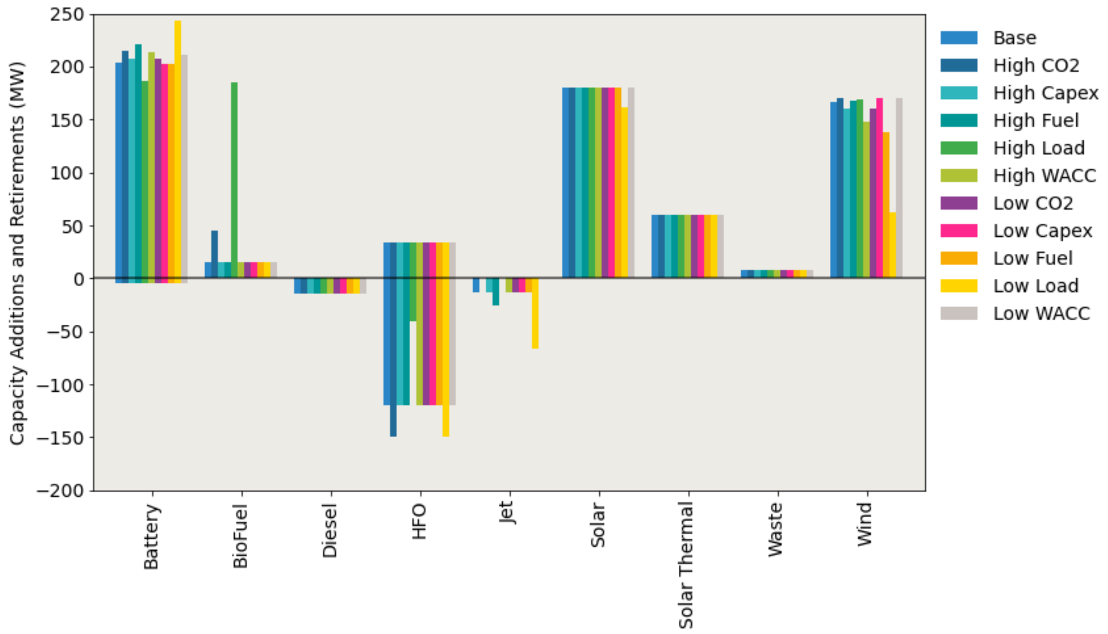
Figure 7.38: Scenario 2 sensitivities capacity additions and retirements



Source: Mott MacDonald

Figure 7.38 shows the same level of sensitivity of each technology type compared to Scenario 1 with the exception of CSP which is highly sensitive in Scenario 1, but robust in Scenarios 2 and 3, indicating that based on economic parameters alone, the decision is marginal but when internalising the carbon price, it clearly gains favour. Due to the carbon price being internalised, the system builds additional biofuel plants (OCGT and MSD units) to minimise overall costs when system load is high, this is compared to Scenario 1 where more diesel and HFO plants are built instead. The high uptake in new biofuel plants for the high load scenario explains the high NPV

Figure 7.39: Scenario 3 sensitivities capacity additions and retirements



Source: Mott MacDonald

Figure 7.39 shows robust builds and retirements across all sensitivities with the exception of battery and wind capacity additions. Biofuel and waste are forced in and only two sensitivities are incentivised to build more biofuel; the high CO2 and high load scenario. The high CO2 scenario is the only one that converts an existing HFO unit (D14) and converts it to operate on biofuel. This is intuitive to reduce carbon emissions without incurring a high cost. The firm renewable generation forced online in Scenario 3 encourages the retirement of jet engines. The only two exceptions are the high load scenario which requires the capacity to meet demand and the high CO2 scenario, which is able to dispatch economically with the converted unit reducing carbon emissions.

7.3 Conclusion

This section summarises the generation planning study findings and also highlights some findings for future IRRP studies, which we would expect to be undertaken periodically.

Scenario 2 is only 3.5% more expensive in NPV terms than the LCP, Scenario 1. Scenario 3 is 14.5% higher cost than the LCP. Although the LCP treats carbon emissions cost as an externality, the NPV has been adjusted to include the cost of carbon emissions for a fair comparison. Scenario 3 comes at a higher cost than Scenario 2 because it includes more expensive generation technologies, in particular Waste to Energy, Landfill Gas, and Biomass.

The competitive position of VRE in Barbados is such that even in Scenario 1, the LCP, where carbon emission costs are treated as an externality, the power system would be expected to achieve substantial decarbonisation by 2030 – achieving an 88% reduction in CO2 emissions in 2021. This is because solar PV and Wind generation are clearly on the least cost development path and even including the necessary BESS to firm up and balance the grid. This is evident from the capacity additions for these technologies being very similar across scenarios.

Scenario 1 and 2 see emissions fall to 12% and 6.7% of current levels, respectively. However, Scenario 3 achieves the lowest emissions by 2030, reducing to 5% of current levels. The deepest decarbonisation is achieved in Scenario 3 as a result of the additions of the firm renewables (WTE, landfill gas, and biomass), which albeit expensive generation technologies, allow for additional retirement of existing thermal plant which are otherwise required for back-up power generation. It is also evident that the cost of carbon emissions reduction faces decreasing marginal returns, which is generally a well-known phenomenon, given that the first 88% of decarbonisation is achieved without intervention while the next 5% of decarbonisation (93.3% decarbonisation) results only in a 3.5% NPV premium and Scenario 3 achieves a 95% decarbonisation at a 10.7% premium (total premium of 14.5%). None of the scenarios achieved a 100% decarbonisation as set out in the BNEP 2019-2030 and that it would require increasingly higher premia to achieve this.

The sensitivity analysis conducted for this study has shown that the NPV of Scenario 1 is most sensitive to an increase in demand, a reduction in fuel prices and an increase in WACC. Scenario 2 is much more sensitive to WACC and demand but much less to fuel prices (similar order to capex). As the effect of the carbon price is to substitute investment in VRE for combustion of fuel, this is a very intuitive finding. Scenario 3 is similar to Scenario 2 with the sensitivity to capex gaining importance, however, which again is intuitive given the introduction of expensive firm RES technologies.

Cumulative carbon emissions are not very sensitive overall to any of the variable studied but the sensitivities still reveal some interesting findings: Fuel prices have a bigger impact on carbon emissions than the carbon price sensitivities chosen.

The technology mix chosen is generally largely robust in the sensitivity analysis with the exceptions being the cumulative additions of wind and BESS capacity in conjunction with the level of retirements of HFO plant which appear to be somewhat sensitive across all three scenarios. CSP is highly sensitive in Scenario 1, but robust in Scenarios 2 and 3, indicating that based on economic parameters alone, the decision is marginal but when internalising the carbon price, it clearly gains favour. Existing jet engines across all three scenarios are only ever retired under the low load sensitivity, although a few units are retired under Scenario 3 base also. It should of course be noted that timing of expansions and retirements are more sensitive than the cumulative outcome.

The study has shown that with the expected base case carbon pricing, conversions of existing fossil fuel generation plant to biofuel plant would not be cost-effective. Under the high carbon price sensitivity, only Scenario 3 converts unit D14.

The undiscounted cumulative investment over the study horizon needed to achieve Scenario 2 and 3 is estimated at Billion BBD 2.27 and 2.59, respectively compared to 1.90 in the LCP. As seen, however, against this are significant reductions in fuel imports that are achieved by the more aggressive decarbonisation scenarios.

It should also be noted that with high levels of VRE and low levels of synchronous generation, the power system will become more difficult to operate requiring more systematic data collection and state of the art forecasting of load and renewable resource availability. For system planners, it is also significantly more difficult to model the interactions between optimal planting, dispatch, and reliability in such a modern system as it pushes the boundaries of software, available data, and computation resources, which requires planners to be well equipped and experienced in modern IRRP planning methodologies and software.

The need for operating reserves increases at the same time as more competitive options for the provision of these become available in the form of BESS. Also, the complimentary role of EV role out in the effort to decarbonise the power system should be noted. If EV charging regimes can be smart and flexible (as assumed to be the case in this study), the system cost can significantly reduce thanks to EVs taking a role in demand and supply balancing as well as providing operating reserves akin to the existing UFLS.

Transmission Planning Study

8 Transmission Planning Study

This section provides an overview of the transmission planning assumptions, methodology results and conclusions. We have run transmission planning studies in ETAP using the ETAP model released by BLPC, to ensure that the transmission system is able to incorporate future planned generation and demand.

We discuss the transmission studies for 2021, 2025 and 2030 using the system configuration, hourly dispatch, and load from the base case Scenario 3 of the PLEXOS generation expansion study.

8.1 Assumptions

Transmission study assumptions are included in Appendix H.1.

8.2 Methodology

The transmission study methodology is included in Appendix H.2.

8.2.1 System modelling

8.2.1.1 Load allocation

Table 8.1 below shows load allocation for the transmission planning study scenarios investigated. Winter peak load values have been used as these are the absolute peak values which are most onerous for transmission planning studies.

The load is categorized as below:

- 12 noon load – system peak load (maximum); and
- 5 am load – system minimum load (minimum).

It should be noted that the load values shown include EV loads for both 2025 and 2030.

Table 8.1: Load allocation for the transmission planning study scenarios investigated

Substation	Bus voltage (kV)	Rated Power (MW)					
		2021		2025		2030	
		Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Load bus 1	24.9	2.79	6.75	2.88	7.00	2.88	7.01
Substation 2	11.0	0.87	1.88	1.13	3.07	2.15	6.54
Substation 3	11.0	1.91	4.39	2.20	5.67	3.22	9.15
Substation 4	11.0	2.67	6.24	2.99	7.59	4.01	11.07
Substation 5	11.0	0.43	0.79	0.67	1.94	1.69	5.42
Substation 6	11.0	2.89	6.76	3.21	8.13	4.23	11.61
Substation 7	11.0	2.99	7.01	3.32	8.38	4.34	11.86
Substation 8	11.0	4.07	9.62	4.44	11.09	5.46	14.58
Substation 9	11.0	5.30	12.60	5.71	14.17	6.73	17.67
Substation 10	11.0	1.14	2.51	1.40	3.73	2.42	7.20
Substation 11	11.0	3.61	8.51	3.96	9.94	4.98	13.42

Substation	Bus voltage (kV)			Rated Power (MW)			
Substation 12	11.0	6.63	15.83	7.08	17.52	8.10	21.02
Substation 13 - Transformer 1	11.0	3.26	7.78	3.49	8.62	4.00	10.37
Substation 13 – Transformer 2	11.0	3.26	7.78	3.49	8.62	4.00	10.37
Substation 14	11.0	4.04	9.55	4.40	11.01	5.42	14.50
Substation 15	11.0	5.34	12.70	5.75	14.28	6.77	17.77
Substation 16	11.0	5.39	12.83	5.80	14.42	6.83	17.91
Substation 17	11.0	2.55	5.93	2.86	7.27	3.88	10.75
Substation 18	11.0	4.97	11.81	5.37	13.36	6.39	16.85
Load bus 19	24.9	3.37	8.16	3.48	8.46	3.48	8.47
Substation 20	11.0	0.10	0.01	0.33	1.14	1.35	4.61
Total system load		**67.55**	**159.44**	**73.96**	**185.39**	**92.34**	**248.16**

Source: Mott MacDonald

8.2.1.2 Installed generation and BESSs

Dispatched generation for 2021, 2025, and 2030 was obtained from the generation planning task. Generation consists of synchronous and VRE generators. BESS plants were also obtained from the generation planning task. Details on the installed generation and BESSs are provided in Appendix H.3.

8.3 Mitigations to growing VRE penetration on the BLPC system

High VRE generation or high inverter-based generation and storage systems such as BESSs have low inertia and low fault level. Fault level is required to reduce excessive bus voltage fluctuations as load currents and harmonic currents change. Inertia is required to maintain system frequency after system disturbances (such as the sudden loss of generation or load). Synchronous generation have rotational inertia which have historically been used to maintain generator synchronous speed or frequency. A number of academic articles have been written on mitigating the effects of high VRE penetration on power systems [1], i.e., systems where VRE generation approaches 100% of system generation.

Synchronous Condensers (SCOs) can be used to increase fault level, inertia, and dynamic reactive power (MVAr) response on high-penetration, low-inertia, and low fault level VRE systems. As SCOs are spinning machines without prime movers (i.e., without steam, fuel, or water turbines), they do not provide real power (MWs).

SCOs aid in system voltage regulation by dynamically absorbing or supplying reactive power to an electricity grid in response to system voltage changes. SCOs' ability to absorb or produce reactive power dynamically provides grid stability against transient fault conditions. Since SCOs are synchronous with the grid and rely on the grid to be energised such that their rotating mass spins, they continuously draw a small amount of spinning-inertia power (losses) from the grid during operation.

Another technology to mitigate the reduction in inertia and dynamic reactive power is a grid-forming inverter normally configured as a grid-forming BESS. Grid-forming BESSs can provide synthetic inertia, fast-acting real power (MWs) and dynamic reactive power response, however they do not provide fault level. 100% grid-forming inverter systems (i.e., systems with no synchronous generation) are still not proven for large integrated systems.

The intermittency or non-dispatchability of high VRE systems can be mitigated using flexible and responsive energy storage as discussed in section 6. Dynamic voltage control of high VRE systems can be achieved from the following devices:

- The dynamic reactive power, and voltage control capabilities of conventional generation, VRE, and BESS systems;
- SCOs;
- Static VAr Compensators (SVCs) and STATCOMs.

While circuit breaker-switched or contactor-switched shunt capacitor banks and shunt reactor banks can provide shunt reactive power support, they cannot provide dynamic reactive power support and their operation is normally associated with 50 ms to 100 ms delays from protection relay delays and delays arising from the opening and closing of the circuit breakers and/or contactors.

New SCOs can be purchased, or existing thermal synchronous power plants can be re-purposed as SCOs (if technically feasible) in the following ways:

- By installing a clutch between the turbine and the generator or alternator so that most of the time the generator is running in SCO mode, however for extreme weather events, the turbine can be run up to synchronous speed and connected to the generator via the clutch and the generator run in full power (MW and MVAr) mode. The additional benefit of keeping the prime mover in service is that a separate pony motor is not required to run the generator/alternator up to synchronous speed;
- By decommissioning the turbine or prime mover and retrofitting a pony motor to run the generator/alternator to get the generator/alternator up to synchronous speed for operation. Care needs to be taken to ensure all the necessary cooling and lubrication systems for the generator/alternator can still run correctly with the turbine or prime mover disconnected;

As soon as the generator is disengaged from the engine, the engine can be shut down and the generators can continue operating in SCO mode.

For Barbados, we recommend several 8 MVA or 10 MVA SCOs for the following reasons:

- Providing fault level at multiple points in the network for legacy protection systems and voltage stability;
- Providing overall system inertia for frequency response;
- Providing dynamic voltage support at multiple points in the network for steady state and transient stability response.

8.4 Transmission planning results

To determine the system adequacy from 2021 to 2030 considering equipment loading limits and system voltage profiles, we undertook N-0 and N-1 studies for the maximum loading condition which was at the following time of the day:

- 12noon system peak

For the N-1 studies the contingencies resulting in system inadequacies are discussed.

Detailed load flow results for the investigated 2021, 2025 and 2030 study years are given in Appendix H.4.

In the following sections we describe the steady state and stability studies for the years 2021, 2025, and 2030.

8.4.1 2021 Study

8.4.1.1 2021 Results

There were no system violations for both the N-0 and N-1 studies. The studies were conducted with existing capacitor banks switched in.

8.4.1.2 Proposed mitigation projects

There are no transmission mitigation projects required in the Barbados power system in 2021 as demonstrated by the load flow results.

8.4.2 2025 Study

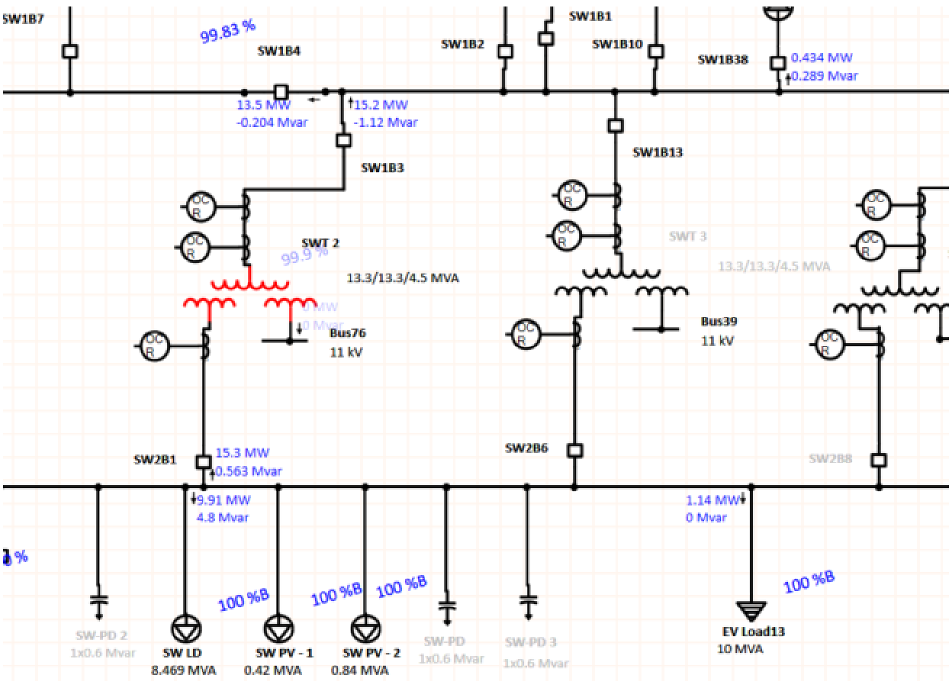
8.4.2.1 2025 Results

System violations were found with the following lines and transformers for N-0 studies:

- Substation 14 13.3 MVA, 24.9/11 kV transformer loaded to 115%.

The Substation 14 transformer overload is due to the evacuation of 15.3 MW of power from the 20 MW CSP generator connected at the Substation 14's 11 kV bus. Figure 8.1 below shows the overloaded Substation 14 13.3 MVA transformer (highlighted in red).

Figure 8.1: 2025 Substation 14 transformer overload



Source: ETAP Simulation Model Screenshot

In addition to the Substation 14 transformer overload, low voltage limit violations were recorded at the Substation 12 and Substation 15's 11 kV buses. The low voltages were experienced throughout the system due to insufficient reactive power after the removal of several existing synchronous generators. This was mitigated by connecting capacitor banks and SCOs in the network.

There were no recorded system violations for the N-1 studies.

It should be noted that approximately 80 MW of conventional thermal synchronous generation is retired by 2025, a large portion of it being at Substation 12. However, an additional 43 MW of renewable synchronous generation is installed in the network in the same year. The significant decrease in the overall installed system synchronous generation necessitates the installation of SCOs from 2025, not only for voltage but also for fault level support. More detail on this is found in Section 8.4.5 which discusses the fault level analysis findings.

Cruise liner load of 4.5 MW can be fed from the Substation 15 distribution system.

8.4.2.2 Proposed mitigation projects

Transmission mitigation projects required in the Barbados power system in 2025 are shown in Table 8.2 below. Budget costs have been derived from [59][60] as well as project experience. Budget costs have an estimated accuracy of ± 20%.

Table 8.2: 2025 Mitigation Projects

No.	Description	Project Date	Estimated Project Cost (Mio USD)
1	1 x 13.3 MVA 24.9/11 kV transformer, Substation 14	2025	0.420
2	1 x 1 MVAr Capacitor Bank, Substation 15	2025	0.020
3	4 x 10 MVA SCO Substation 12	2025	8.000
4	2 x 10 MVAr Capacitor Banks, Substation 12	2025	0.400

Source: Mott MacDonald

8.4.3 2030 Study

8.4.3.1 2030 Results

System violations were found with the transformers shown in Table 8.3 for N-0 studies:

Table 8.3: 2030 N-0 transformer overloads

Transformer	Rating (MVA)	MW Flow (MW)	% Loading	Comments
Substation 10 24.9/11 kV	13.3/13.3/4.5	15.3	123.2	Overloaded due to projected load growth at Substation 10's 11 kV bus
Substation 12 24.9/11 kV	20/20/6.667	21.0	112.3	Overloaded due to projected load growth at Substation 12's11 kV bus
Substation 11 24.9/11 kV	13.3/13.3/4.5	13.4	106.4	Overloaded due to projected load growth at Substation 11's 11 kV bus
Substation 3 24.9/11 kV	13.3/8.8/4.5	9.2	105.8	Secondary winding overloaded due to projected load growth at Substation 3's 11 kV bus

Source: Mott MacDonald

In addition to the transformer overloads, low voltages were experienced throughout the system due to insufficient reactive power. The low voltages are mitigated by connecting SCOs and additional capacitor banks at strategic points of the network including substations where synchronous generating plants had been retired.

N-1 studies highlighted system violations for the contingency below:

Contingency – Loss Substation 13 – Transformer 1 (20 MVA 24.9/11 kV transformer).

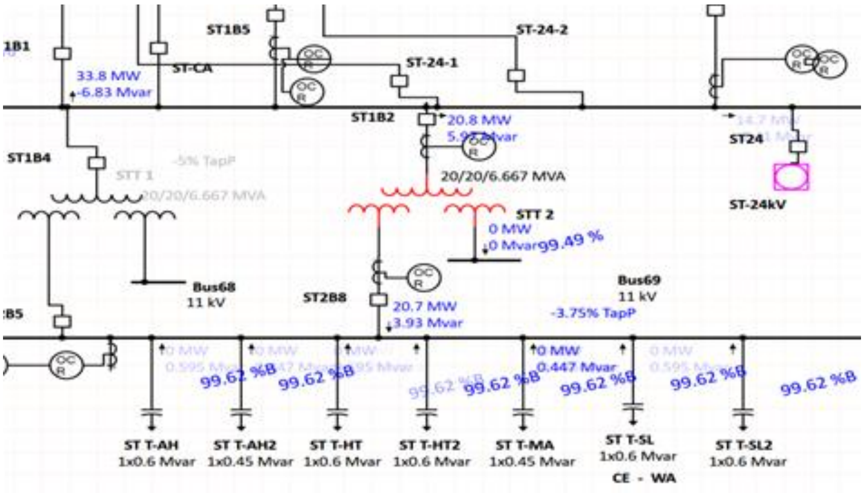
This is necessary to verify whether the remaining transformer has the capacity to supply the load when one transformer trips. It should be noted that most substations in the network only have one transformer, however operation of normally open and normally closed points on the 11 kV system provide N-1 redundancy in the event of a single transformer trip.

The following system violation was observed:

- Remaining Substation 13's 20 MVA 24.9/11 kV Transformer 2 loaded to 108.7%.

The transformer overload was due to the projected 11 kV load growth. The remaining Substation 13's transformer overload is shown in Figure 8.2.

Figure 8.2: 2025 Substation 14 transformer overload



Source: ETAP Simulation Model Screenshot

The transformer overloads shown in Figure 8.2 can be mitigated by either supplying an additional transformer or reallocating and redistributing loads at the 11 kV voltage level.

As cruise liner load grows to 18 MVA, a new 24.9/11 kV substation should be installed close to the cruise liner berthing points. The new port transmission substation can be connected to Substation 12 and Substation 15.

8.4.3.2 Proposed mitigation projects

Transmission mitigation projects required in the Barbados power system in 2030 are shown in Table 8.4 below. Costs have been derived from [59][60] as well as project experience.

Table 8.4: 2030 Mitigation Projects

No.	Description	Project Date	Estimated Project Cost (Mio USD)
1	1 x 24.9/11 kV 13.3 MVA transformer, Substation 14	2025	0.420
2	1 x 1 MVAr Capacitor Bank, Substation 15	2025	0.020
3	4 x 10 MVA SCO Substation 12	2025	8.000
4	2 x 10 MVAr Capacitor Banks, Substation 12	2025	0.400
5	1 x 24.9/11 kV 13.3 MVA transformer, Substation 10	2030	0.420
6	1 x 24.9/11 kV 13.3 MVA transformer, Substation 11	2030	0.420
7	1 x 24.9/11 kV 13.3 MVA transformer, Substation 3	2030	0.420
8	1 x 24.9/11 kV 20 MVA transformer, Substation 12	2030	0.510
9	1 x 24.9/11 kV 20 MVA transformer, Substation 13	2030	0.510
10	2 x 10 MVAr Capacitor Banks, Substation 12	2030	0.400
11	1 x 5 MVAr Capacitor Bank, Substation 15	2030	0.100
12	1 x 20 MVAr Capacitor Bank, Substation 4	2030	0.400
13	1 x 10 MVA SCO Substation 15	2030	2.000
14	1 x 10 MVA SCO Substation 4	2030	2.000
15	1 X 3 MVAr Capacitor Bank, Load bus 19	2030	0.060

Source: Mott MacDonald

Considering BLPC's decision to purchase only 20 MVA transformers going forward, it should be noted that if 20MVA transformers are to replace the 13.3 MVA transformers no additional transformers may be required at these substations to supply the 11 kV load growth. More detailed studies would be required as the transformers get upgraded. It should further be noted that the IRRP is a guide only, and as specific projects enter the 5-year and 2-year windows, more detailed studies and designs are recommended.

8.4.4 Loss analysis

The Barbados system losses are recorded and compared for the scenarios before and after the integration of the various power plants and transmission infrastructure. The findings are shown in Table 8.5 below.

Table 8.5: System losses for 2021, 2025 and 2030

Study year	Maximum			Minimum		
	Loss (MW)	Generation (MW)	Loss (%)	Loss (MW)	Generation (MW)	Loss (%)
2021	4.2	162.2	2.6	1.1	78.1	1.4
2025	2.5	202.5	1.2	3.3	76.7	4.3
2030	5.7	322.1	1.8	2.1	94.6	2.2

Source: Mott MacDonald

The results from the loss analysis study show that there is an overall increase in system losses as the system evolves towards 100% RE penetration. This is due to the growing loads distributed across the existing 11 kV substation buses. The load growth results in an increase in losses as more power is evacuated through existing lines and transformers. This is particularly true at the substations where there is no locally connected generation or where generation is connected at the 24.9 kV bus.

However, when the losses are measured as a percentage of the total system generation, the overall system loss percentages fall within normal limits [58]. A more detailed breakdown of the system losses recorded for the major system transformers and existing transmission lines is shown in Appendix H.5.

8.4.5 Fault studies

Three phase faults were applied to the system at system maximum loading with and without SCOs. The fault level results were calculated at the 11 kV, 24.9 kV, and 69 kV system buses. 11 kV and 24.9 kV fault level results at selected buses are shown in Table 8.6 below. Detailed results are shown in Appendix H.4.

Table 8.6: Fault levels for 2021, 2025, and 2030 with and without SCOs

Bus Name	Voltage (kV)	Fault Levels (kA)				
		2021 Maximum	2025 Maximum	2025 Maximum SCOs	2030 Maximum	2030 Maximum SCOs
SP4-24a	24.9	19.8	13.0	14.2	11.3	14.7
SP6-11a	11	33.7	19.9	22.7	17.8	22.8
SP3-11a	11	32.7	22.3	23.4	16.8	23.4
TR24	24.9	8.8	7.3	7.4	8.1	8.5
TR11-a	11	19.1	14.0	14.2	16.5	17.0
CE1-24a	24.9	16.0	12.6	13.3	11.9	14.1
CE2-11	11	6.0	5.8	5.8	5.7	5.9
TY1-24	24.9	15.9	11.8	12.6	10.7	13.0
TY2-11a	11	7.7	7.4	7.5	7.3	7.5
MS1-24	24.9	14.7	11.3	11.9	10.3	12.3
MS2-11	11	10.1	9.4	9.6	9.2	9.7
ST2-11	11	13.8	12.6	12.8	12.8	13.4
ST1-24	24.9	10.7	9.0	9.2	9.2	10.0
SW1-24	24.9	10.7	10.1	10.5	10.3	11.5
SW2-11	11	7.2	15.4	15.5	20.5	21.1

Source: Mott MacDonald

Three phase faults were applied to the system at system maximum loading with and without SCOs. The fault level results were calculated at the 11 kV, 24.9 kV, and 69 kV system buses. 11 kV and 24.9 kV fault level results at selected buses are shown in Table 8.6 below. Detailed results are shown in Appendix H.4.

Fault levels generally decrease from 2021 to 2030 when SCOs are not in service. The fault study results show the largest reduction in fault levels at the Substation 12 (highlighted in grey in Table 8.6 above) from 2025, as the Substation 12 synchronous generators are retired. Substation 12's 11 kV bus fault levels reduce from 33.7 kA in 2021 to 19.9 kA in 2030. Significant fault level reductions were also recorded at buses adjacent to Substation 12. Connecting SCOs to the Substation 12 returns fault levels to values within the expected 25 kA circuit breaker limits. It is necessary for system fault levels to be maintained as VRE generation penetration increases to avoid invalidating existing system protection grading settings. Low fault levels also exacerbate voltage dips and harmonic voltage levels.

Fault levels at Substation 14 increase from 2021 to 2030 due to new installed CSP power plants at this site. The fault levels however remain within the limits of typical 11 kV circuit breaker ratings.

8.4.6 Stability studies

Frequency studies were conducted on the Barbados network for loss of the largest generating unit. Transient stability studies were conducted for a fault on the Substation 20 to Substation 13 line and the line tripped.

In frequency stability studies, if a large generator is tripped (automatically switched out) on a power system, the speed of the remaining generators decrease as there is a generation/load imbalance. As their rotational speed decreases, governing action increases generator output for designated generators and system frequency is restored. In modern high-VRE systems, fast-acting BESSs also provide “governing” reserve and real power reserve.

In transient stability studies, if a transmission line experiences a permanent three-phase fault, voltages in proximity to the fault go to zero or approach zero, and after a designated time-delay, the circuit breakers on adjacent ends of the transmission line open, removing the fault condition. During the fault period, normally ranging from 80ms to 140ms, the system is stressed as large amounts of fault current supply the fault, and rotor angles of nearby generators start to move out of synchronism with the rest of the power system. If the synchronising torque between the generators close to the fault and the rest of the generation system is low, rotor angles can move past their safe operating range and the generators experience “rotor slip” and trip.

The study years considered were 2021, 2025, and 2030. Stability studies were carried out for the minimum loading condition as it is the most onerous. The most onerous generator trips identified are presented in Table 8.7 below.

Table 8.7: Generator unit trips for frequency stability studies

Study Year	Minimum Load	
	Generator tripped	**Generator rating (MW)**
2021	D15	27
2025	MSD Resiliency Bridge	34
2030	Solar CSP1 - 15h TES	20

Source: Mott MacDonald

The impact of the loss of a large share of large VRE was not investigated as the synchronous generator trips provide the worst-case results. Synchronous generator loss implies loss of system inertia in addition to the machine’s real and reactive power support. Intermittency impacts are longer-term impacts (in the order of minutes) and are catered for in the PLEXOS reserve and ramping analysis.

The events considered for frequency and transient stability studies are described below:

Frequency Event:

- Trip the largest generator at t = 5 seconds

Transient Events:

- Apply a 120 ms, three (3) phase bolted fault at the Substation 20 to Substation 13 line at t = 5.0 seconds
- Clear the fault at t = 5.12 seconds
- Trip the Substation 20 to Substation 13 line at t = 5.12 seconds

To ensure system stability in the event of a large generator trip, the existing underfrequency load shedding (UFLS) relays were invoked according the BLPC UFLS schedule.

8.4.6.1 2021 Frequency Stability Study Results

The 2021 system is the system status at date of this report and the stability studies exclude the investigation of SCOs and large increments of solar PV, wind, and batteries. Figure 8.3, column one (1) below shows responses for the system frequency, and the real and reactive power of the existing Substation 20 battery for a trip of the 27 MW D15 generator in Substation 12 at 5 seconds. The frequency drops, there is a turning point (or nadir) and the there is a small overshoot before the frequency settles at 49.97 Hz and the system is stable. The Substation 20 5MW battery (2nd row, 1st column) real power changes from 0 MW to 5 MW immediately after the generator is tripped but as loads are tripped to implement UFLS the real power from the battery changes and settles at 0.507 MW export while the reactive power changes from 0 MVAr to -0.779 MVAr following the generator trip.

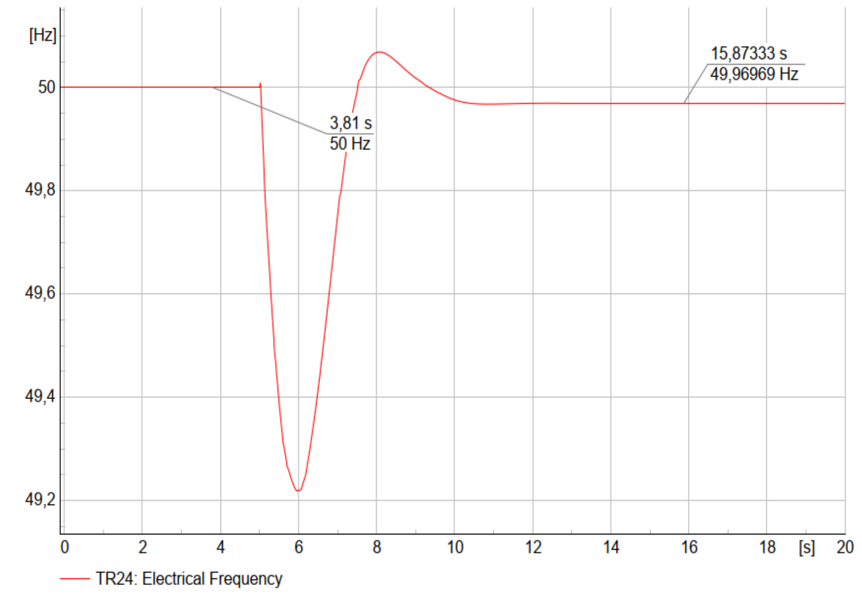
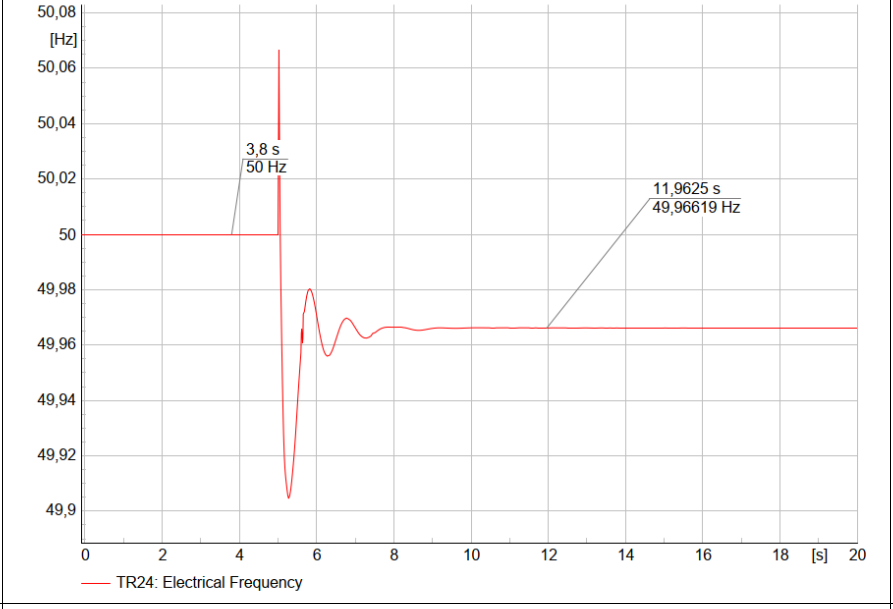
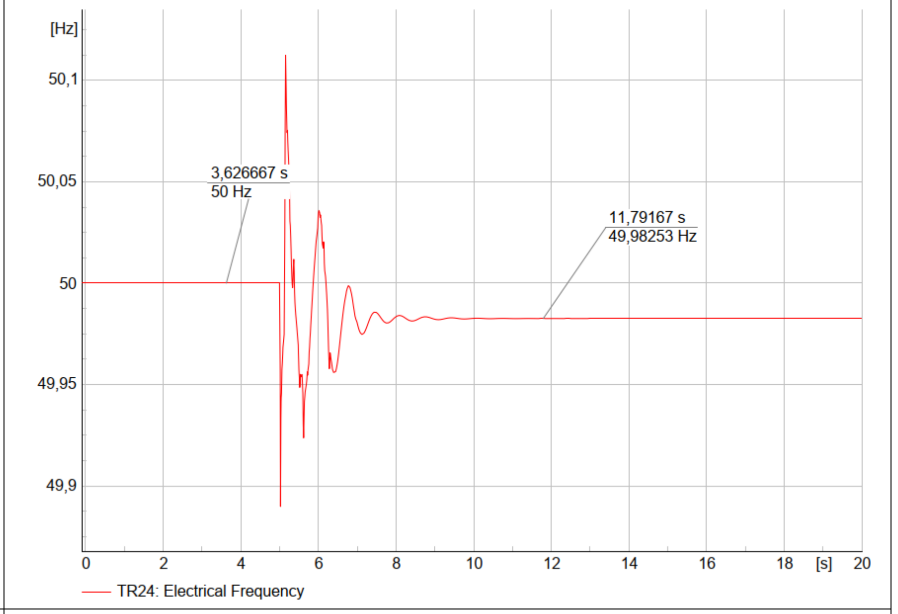
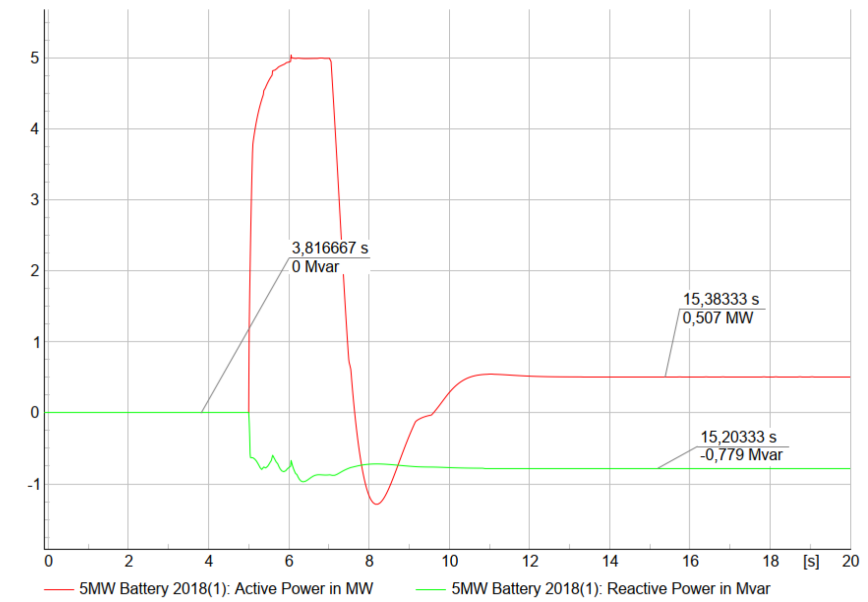
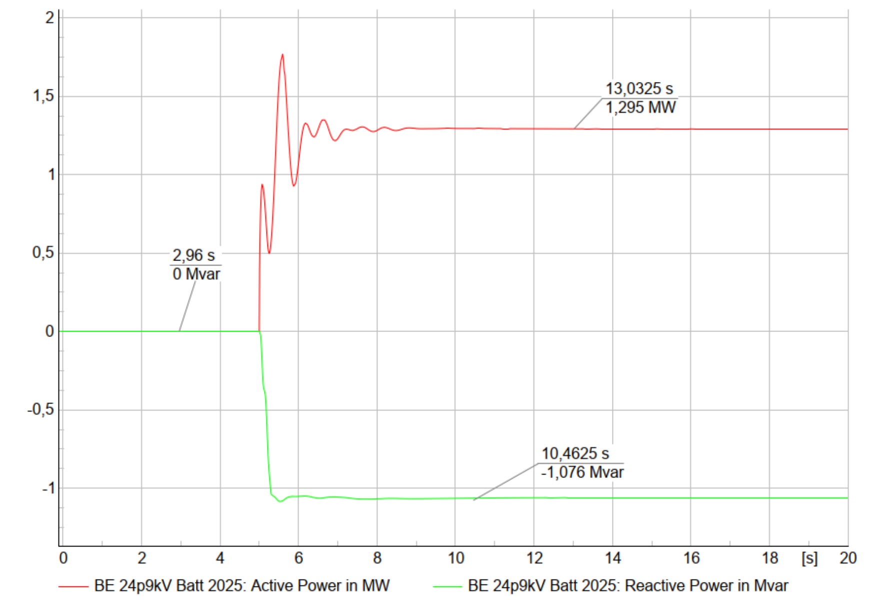
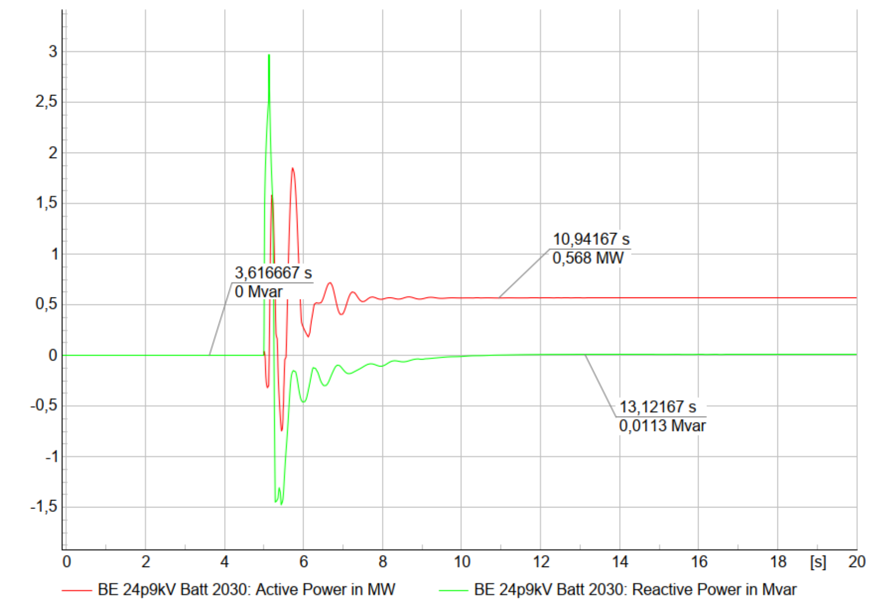
8.4.6.2 2025 Frequency Stability Study Results

Figure 8.3, column two (2) below shows responses for the system frequency and the real, and reactive power of the Substation 2 battery in 2025. The 34.04 MW MSD resiliency bridge generator is tripped at 5 seconds during system minimum conditions. It can be seen that the frequency recovers to 49.97 Hz and the system is stable. No UFLS is required in 2025. The battery real power changes from 0 MW to 1.295 MW while the reactive power changes from 0 MVAr to -1.076 MVAr following the generator trip. In 2025, there are several BESSs contributing to frequency stability.

8.4.6.3 2030 Frequency Stability Study Results

Figure 8.3, column three (3) below shows responses for the system frequency, real and reactive power of the Substation 2 battery in 2030. The CSP1 - 15h TES 20 MW generator is tripped at 5 seconds during system minimum conditions. It can be seen that the frequency recovers to 49.98 Hz and the system is stable. The battery real power changes from 0 MW to 0.568 MW while the reactive power changes from 0 MVAr to 0.011 MVAr following the generator trip.

Figure 8.3: 2021, 2025 and 2030 Minimum Loading frequency stability results

2021 Minimum Loading Scenario	2025 Minimum Loading Scenario	2030 Minimum Loading Scenario
System frequency response	System frequency response	System frequency response
		
Battery response	Battery response	Battery response
		

Source: Mott MacDonald

8.4.6.4 2021 Transient Stability Studies

Transient stability studies were undertaken for 3-phase line fault and line-trip conditions.

Figure 8.4 below shows two rows of figures. The top row shows the rotor angles of identified generators at Substation 12 relative to the Trents Resiliency Bridge generators for the years 2021, 2025 and 2030 after for a three-phase fault and trip of the Substation 20 to Substation 13 line. The bottom row shows the voltage response at Substation 12 resulting from the three-phase fault that was applied to the Substation 20 to Substation 13 line.

In 2021 (top, left-most column), the rotor angles of the Substation 12 generators deviate by ten (10) degrees and return to a settling power angle.

In 2025, (top middle column), the rotor angles of the waste and biomass generators deviate by approximately 10 degrees before returning to a settling power angle.

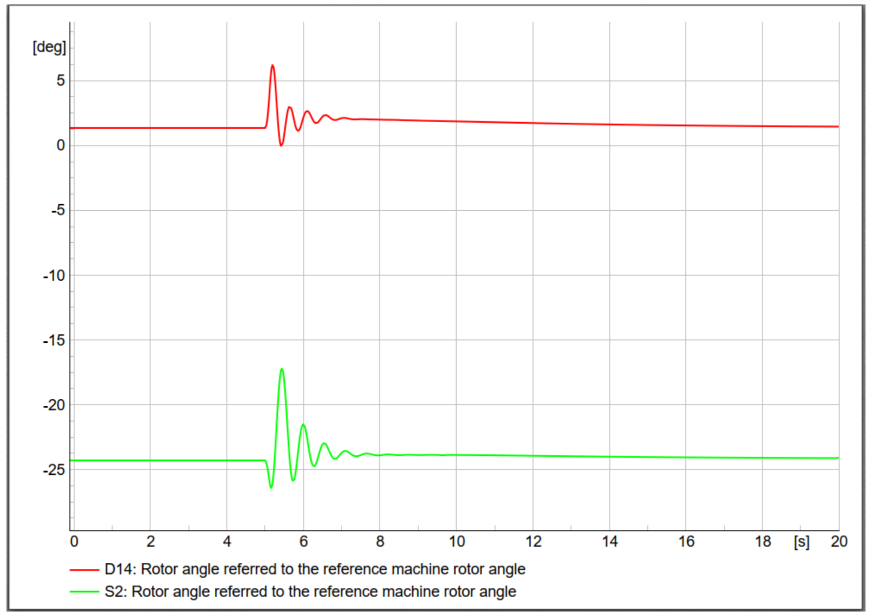
2030 is similar to 2025 (top, right most column) with a rotor angle deviation of the waste and biomass generators before settling.

The voltage figures in the bottom row show bus voltages approaching zero for the 120ms duration of the fault, and the voltage returning to normal line voltage after a small overshoot.

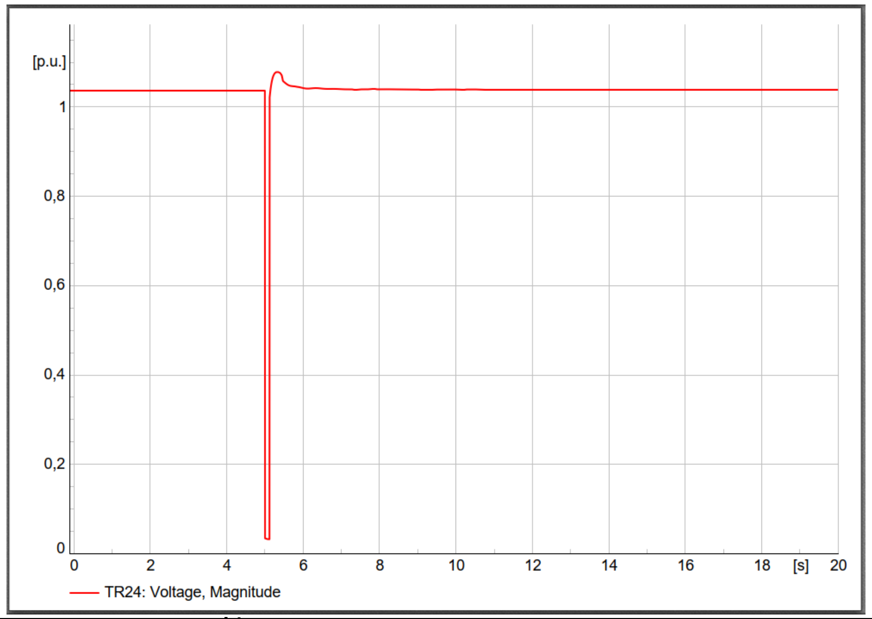
Figure 8.4: 2021 Minimum Loading transient stability results

2021 Minimum Loading Scenario

Rotor Angle response

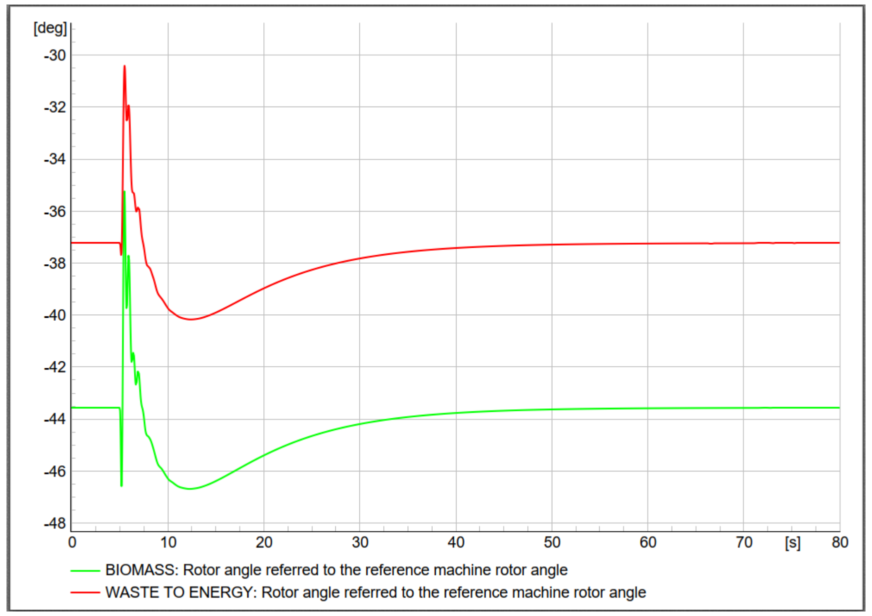


Trents bus voltage

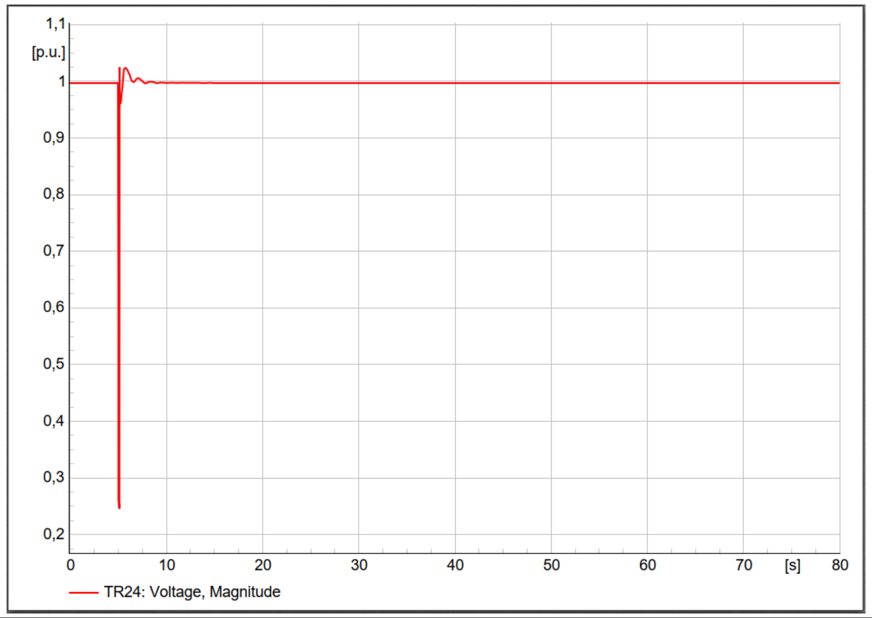


2025 Minimum Loading Scenario

Rotor Angle response

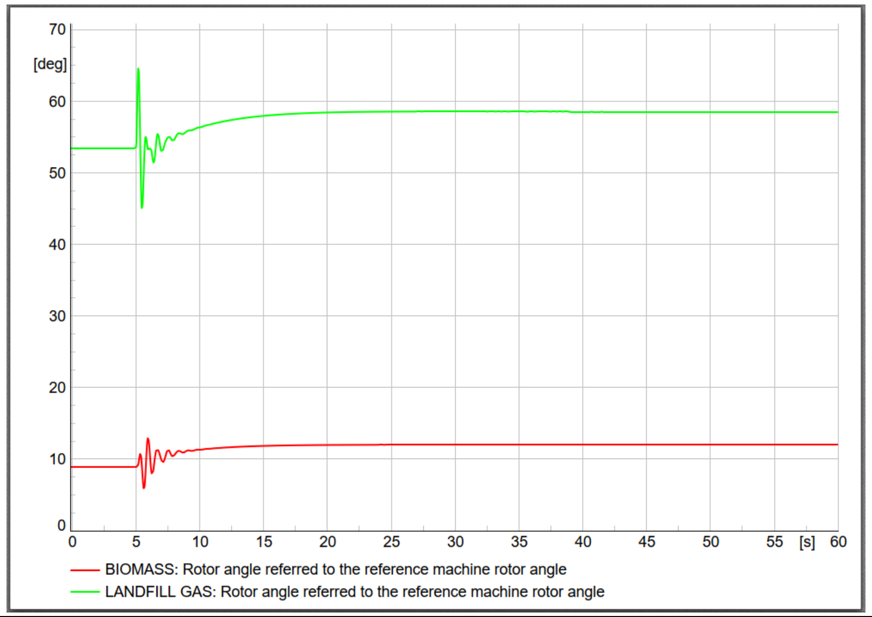


Trents bus voltage

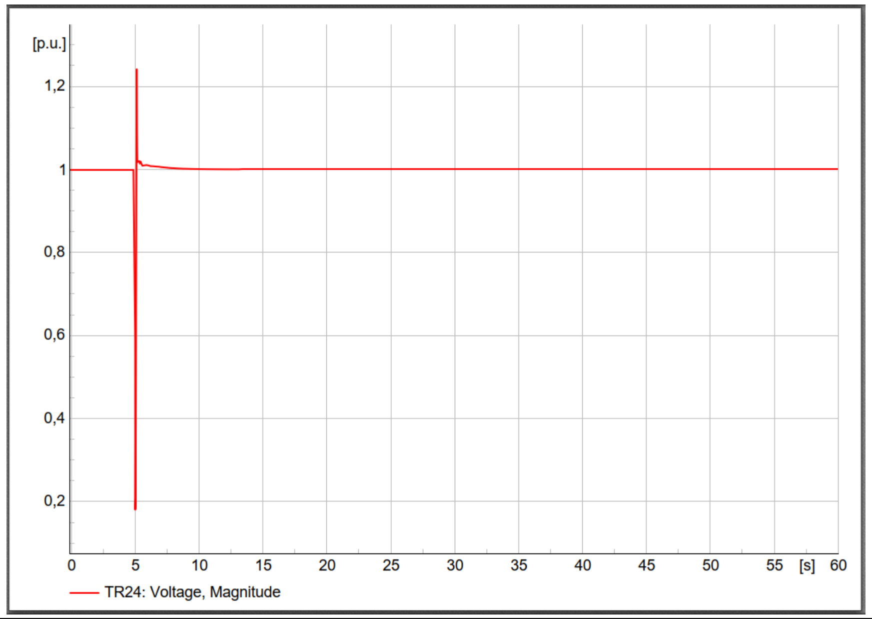


2030 Minimum Loading Scenario

Rotor Angle response



Trents bus voltage



Source: Mott MacDonald

8.5 Resilience and islanding

Integrated Power Systems (IPSs) have large generators, transmission systems and distribution systems. Recently, distribution systems include generation as well as customer load. This is sometimes referred to as embedded generation. When an unusually large disturbance occurs on a power system (normally resulting from a series of coincident incidents from extreme weather events or operator error) and the frequency cannot be maintained even after UFLS, governor response, BESS action and secondary generator response, generators across the system trip as system frequency exceeds design operating ranges. In these situations, the system experiences a blackout, i.e., there is a total loss of generation. System blackouts are the worst event that can happen on a n IPS and in some jurisdictions it can take up to two weeks to totally restore the IPS.

An IPS can be designed to have electrical islands or sub-islands where generation and load in these islands are mostly matched and where the islands are interconnected with one or more transmission lines. If a serious or large system disturbance occurs as described above, generator and transmission busses in an island can monitor rapid frequency changes and separate from the rest of the IPS, to preserve the supply/demand balance in the island so that the island does not experience a total loss of generation of brown-out/black-out. Partial blackouts are sometimes referred to as brown-outs. Electrical islands reduce IPS restoration times significantly as operational generation can be used to restore the rest of the IPS without the need of black start generation.

For islanding to be effective, loads and generation in islanding zones should be matched. In addition, Rate of Change of Frequency (RoCoF) protection, islanding protection and re-synchronisation protection on transmission lines would need to be designed correctly when separating and re-synchronising islands with other energised islands and the rest of the power system.

Normally re-synchronisation relays are only placed on generators. Placing RoCoF and resynchronisation relays on transmission lines linking islands allows islands to re-synchronise with each other. More work is required to design the system to be able to operate in island mode after severe climate events.

The geographical distribution of VRE generation, synchronous generation, BESSs, and SCOs as proposed in this study will likely assist in islanding design and implementation. A full islanding and resilience study was not included in the scope of this study.

8.6 Conclusions

The transmission system as planned with the necessary mitigation is compliant under normal and emergency conditions for the years studied under N-0 and N-1 conditions. Additional transformers are required at Substation 12, Substation 14, Substation 13, Substation 11, Substation 3, and Substation 10 in 2025 and 2030. These additional transformers are required due to the existing transformers being overloaded by the projected 11 kV load growth except at Substation 14 where the transformer overload was due to high generation levels being evacuated from the Substation 14 11 kV bus. The overloads occurred at system maximum loading conditions. An alternative to supplying additional transformers could be to re-allocate and re-distribute loads and generation at the 11 kV level.

The voltage study identified the following substations to be the most suitable substations for new SCOs:

- Substation 12 10 MVA x 4;

- Substation 4 10 MVA x 1;
- Substation 15 10 MVA x 1;

Cruise liners were successfully initially supplied from the Substation 15 11 kV buses but by 2030, a new “Port” 24.9 kV transmission substation is required in the vicinity of the cruise liners. This new Port Substation can be supplied at 24.9 kV from Substation 15 and Substation 12.

There was an overall increase in system losses as the system evolved towards 100% RE penetration. This is to be expected as generation and loads grow. The overall system losses when measured against the total system generation fall within normal transmission loss values.

Fault levels reduce as VRE penetration increases which is to be expected as the quantum of synchronous generators decreases and inverter-based generators and BESSs increase. SCOs maintain fault levels to acceptable levels for system max and system minimum conditions for the study years: 2025 and 2030.

In 2021, for the trip of the largest generating unit in Barbados, UFLS is invoked to keep the system frequency-stable. The system is frequency stable for the years 2025 and 2030 for the trip of large generators, as new synchronous generating capacity, VRE generation capacity, SCOs, and BESSs are installed.

The BESSs successfully supply fast-acting real power (MW) support and the SCOs provide inertia and dynamic voltage support. The BLPC system is transiently stable after the application of a 120 ms line fault and line trip for the years 2021, 2025, and 2030. Transient stability refers to the deviation of synchronous generator rotor angles between each other after the application of onerous three-phase faults on the system.

The distribution of synchronous generation, VRE generation, BESSs, and SCOs will assist in improving the system resilience. Electrical islanding of the Barbados system will be more achievable where localised generation and loads are comparable across the system. Further work and studies are recommended to strengthen the design of the power system to be more resilient for extreme weather events. Such resiliency solutions could include inter alia: conversion of overhead lines to underground cables, raising the installation height of important power stations or flood protection mitigation.

Multi Criteria Assessment Study

9 Multi-Criteria Assessment Study

This section of the report discusses quantitative and qualitative criteria beyond the NPV analysis undertaken in the previous sections and attempts to find the best scenario for Barbados, taking into account a wider set of seven criteria. The impacts of the criteria are calculated, and a weighting or importance is given to each criterion for the three main study scenarios. The scenarios are then ranked based on these economic, social, and environmental criteria.

Scenario 1, the LCP, is the cheapest solution, even when including the cost of carbon emissions and results in an 88% decarbonisation by 2030. Scenario 2 is clearly the most cost-effective way of reducing carbon emissions further, but the 93% decarbonisation achieved comes at a cost premium of 3.5%. For a further 10% premium, Scenario 3 achieves a 95% decarbonisation by 2030 will also providing more fuel diversification and potentially more economic spill-overs to other sectors of the economy.

The MCA attempts to contextualise the relative value of each scenario across a number of socio-economic and environmental factors, which will certainly create a discussion and also provide a basis for further analysis, such as considering the wider economic impact in general equilibrium models.

9.1 Methodology

An IRRP differs from a Power System Masterplan (PSMP) in that a PSMP attempts to find the optimal techno-economic plan over a time period e.g., 10 years, whereas an IRRP is obliged to consider a wider set of criteria across multiple vectors and sectors of an economy e.g., job creation, land use and bio-physical impact. Multi-Criteria Assessment (MCA) is an analytical process that is used to compare and rank electricity generation technologies and scenarios, based on applicable technical, economic, social, and environmental criteria.

Ten criteria were initially identified and discussed with the stakeholders during the diagnostic and interim stages of the project. Following several stakeholder interactions and comments, seven criteria and their weights were finalised as the key measures to evaluate and rank the three generation planning scenarios. The seven criteria are shown in Table 9.1 alongside their respective weights, which reflect the importance of each of the criteria. The MCA methodology in this report involved the following steps.

Table 9.1: MCA Criteria and Weights

No	Criteria	Weight (%)
1	Scenario cost	20
2	Land use	20
3	Water use	15
4	Bio-physical impacts	15
5	Climate resilience	15
6	Job creation	10
7	Construction ESIA impacts	5

Source: Mott MacDonald based on Stakeholder's consultation and comments

9.1.1 Identifying and scoring the different sub-criteria

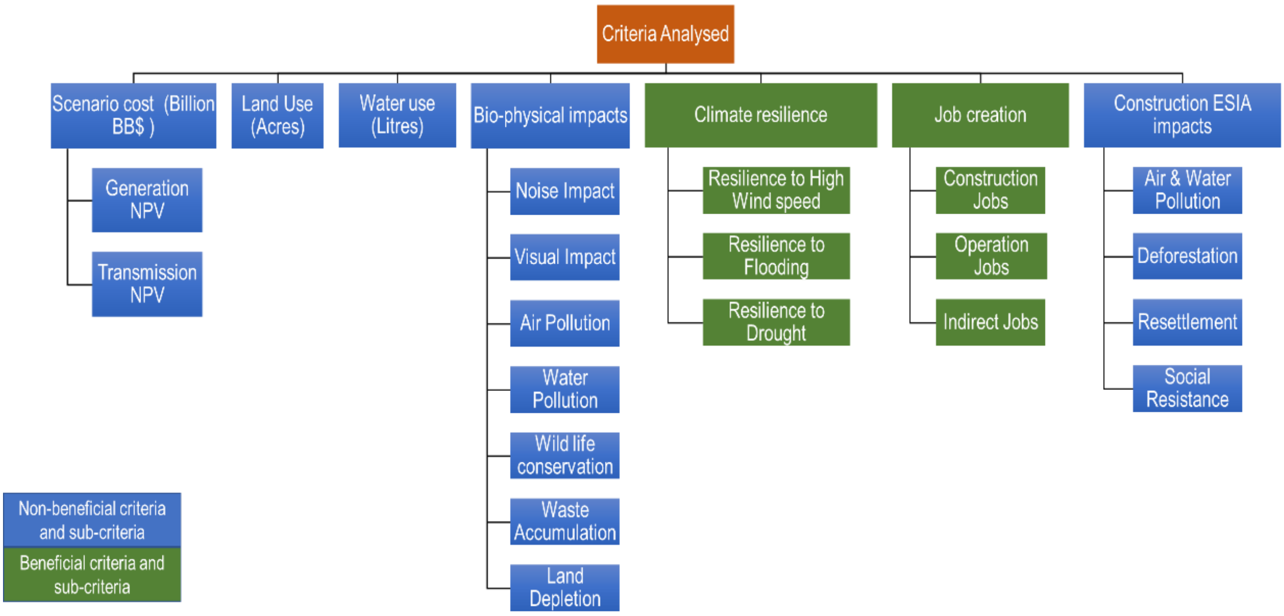
Five of the criteria were further broken down into sub-criteria in order to account for specific issues that could be impacted by the different generation technologies (see Table 9.1). The criteria can be categorised as follows:

- beneficial which indicates that a higher value is better; and
- non-beneficial which indicates that a lower value is better.

The criteria and sub-criteria were evaluated based on the characteristics of the different generation technologies and the quantitative data obtained from the generation and transmission planning results in Section 7 and 8. Detailed information on the scoring of the criteria and their respective sub-criteria are presented in the spreadsheet "Multi-Criteria Assessment for the GoB's IRRP", which has been submitted alongside this report (see Appendix I).

Given that the results from the three scenarios defined in Section 7 have approximately the same capacity for a number of technologies, the MCA assessment is focused on technologies that vary significantly between each of the different scenarios. Therefore, the MCA spreadsheet only includes scoring of criteria and sub-criteria for CSP, wind, biomass, landfill gas and waste technologies.

Figure 9.1: Criteria and sub-criteria used in the MCA analysis



Source: Mott MacDonald

9.1.2 Ranking the three generation planning scenarios

The scores for each of the criteria and sub-criteria (where applicable) are aggregated, normalised, and their respective weights applied. The resultant total values from all the criteria are used to determine the overall ranking of the scenarios.

9.1.3 Sensitivity analysis

We carried out three sensitivity analyses to assess how the different scenarios rank under criteria weights that place significant importance on social and environmental criteria respectively.

9.2 Assumptions

An MCA spreadsheet was circulated to MESBE and discussed with stakeholders in the early stages of the project. The MCA criteria and weights are shown in Table 9.1, with each criterion briefly discussed below.

9.2.1 Scenario Cost

The scenario cost is the total NPV cost (Generation NPV and Transmission NPV) required to install the additional capacities and operate all the installed technologies in each of the three scenarios. This criterion is deemed to be the most important economic criterion; as it highlights how much each of the different scenarios will cost Barbados, and the inability to secure the scenario funds could imply the IRRP for Barbados may not be actualised. The LCP scenario, CO2 scenario, and FRES have a total NPV cost of 13.51, 13.99, and 15.47 Billion BBD respectively. Therefore, LCP scenario ranks as the most economical scenario due to having the lowest NPV cost.

9.2.2 Land Use

Barbados is a densely populated country and thus there is competition for land use. Following the stakeholder's consultation, we identified the three main competitors for land use as: agriculture, VRE power plants, and Biofuel cultivation. Land use has been rated as the most important environmental criterion. The land use requirements of the additional capacities in the LCP scenario, CO2 scenario, and FRES are 6,543, 7,158, and 12,182 acres respectively. The FRES has the highest requirement for land due to the need for cultivation of biofuel crops. LCP therefore ranks as the best scenario with respect to land use.

9.2.3 Water Use

Water consumption in a power plant is proportional to its generated electricity (MWh). The water use criterion has been assigned a comparatively higher weighing, as it captures the impact of additional power plants on the constrained water resource in Barbados. The water quantity used for cooling in thermal power plants is quite similar as presented in Appendix I The Multi-Criteria Assessment Data spreadsheet.

While the water use by the thermal plants is relatively low, biomass has the highest water use due to the water consumption required for biofuel crop cultivation. The estimated water use of the additional capacities between 2025 and 2030 in the LCP scenario, CO2 scenario, and FRES are 814, 3957, and 35,590 million litres respectively. Clearly the LCP scenario ranks as the best scenario with respect to water use only.

9.2.4 Bio-physical impacts

This criterion captures the direct impact of the power plants on the ecosystem within their proximity. This includes noise, visual intrusion, air pollution, water pollution, wildlife conservation, waste accumulation, and land depletion. The operation of biomass, waste, and landfill gas power plants, starting from their farming and landfill sites, tends to have a more positive impact on the ecosystem in comparison to wind and CSP plants (Table I.2). However, despite having these three power plants with low bio-physical impact in its generation mix, FRES is estimated to have the highest bio-physical impact. This is due to the FRES having similar capacity of CSP and wind power plant as the CO2 scenario. Therefore, LCP scenario ranks as the best scenario with respect to bio-physical impact.

9.2.5 Climate Resilience

This criterion reflects the resilience of all the associated infrastructures of a power plant to extreme climate conditions, such as high wind speed, flooding, and drought. High wind speeds (>55mph) will shut down the wind turbine, and could also damage the turbine and Parabolic Trough Collector (PTC) of the CSP plant at a higher speed (>90mph), while also restricting access to the site for repairs. On the other hand, wind and CSP are resilient to flooding and drought especially in comparison to biomass, waste, and landfill gas infrastructures (Table I.3).

The FRES ranks as the scenario with the best climate resilience due to the high aggregated climate resilience score of both waste and landfill gas power plants.

9.2.6 Job creation

This criterion captures the positive impact of job creation in Barbados during construction and operation of the additional power plants in the three scenarios. From the construction perspective, CSP has the highest potential to create on-site jobs (Table I.4), with up to 100 jobs created by site. From an operation perspective, wind, waste, and landfill gas have the highest potential of job creation, with each plant having up to 13 full time employees. Overall, biomass has the highest positive impact due to the indirect jobs that will be created from cultivation and logistics of transporting and processing biofuel crops. The total jobs that could be created in the LCP, CO2, and FRES are 738, 864 and 1330 respectively. Therefore, FRES is ranked as the best scenario with respect to job creation.

9.2.7 Construction ESIA Impacts

This criterion captures the environmental and social impact of constructing additional power plants in the three scenarios. These impacts are air & water pollution, deforestation, resettlement, and social resistance. Based on the aggregated construction ESIA scores for each technology, wind and landfill gas plants are ranked as having the highest and lowest socio-environmental impact during construction (Table I.5). The LCP scenario has the lowest number of additional capacities in comparison to all the three scenarios. Therefore, LCP scenario is estimated to have the least impact during construction and thus ranks as the best scenario with respect to construction ESIA.

9.3 Results

9.3.1 MCA final results

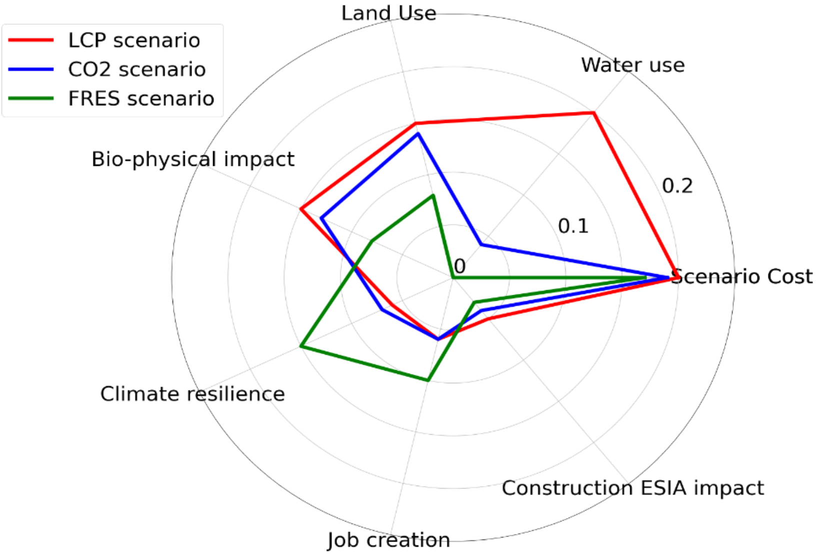
The final score of the scenarios for each criterion is estimated by normalising its criterion values and multiplying it by the criterion weight. The final scores are aggregated, and the three scenarios are ranked. The MCA final score of the three generation planning scenarios in the seven criteria are presented in Figure 9.2. The figure highlights the relationships between the economic, social, and environmental criteria in each scenario.

The LCP scenario has the highest ranking in five criteria, thus highlighting the LCP scenario as the least cost scenario with the lowest impact on improving the climate resilience of the electricity network and creating jobs. One of the key findings of the MCA is that the CO2 scenario ranks second for all seven criteria, despite the scenario being the least cost scenario in terms of reducing carbon emissions.

A key trade-off in the FRES is between both job creation and climate resilience, and the other five criteria. The biomass, landfill gas, and waste plants in the FRES provide the opportunity to create jobs and have a direct positive impact on economic activities, however this comes at the expense of the potentially scarce water and land resource on the island.

Based on the scenario cost and land-use having the highest importance, the overall MCA results shows that the LCP scenario has the highest ranking with a score of 0.86, followed by the CO2 with a score of 0.67, and finally FRES with a score of 0.61 (see Table 9.2).

Figure 9.2: Normalised final criteria scores in the three scenarios



Source: Mott MacDonald

Table 9.2: Final MCA Results

Criteria		LCP	CO2	FRES
Scenario Cost	Scenario Cost (Billion BB$)	13.51	13.99	15.47
	Normalised Scenario Cost	1.00	0.97	0.87
	Weight	0.20	0.20	0.20
	Scenario cost Final Score	0.20	0.19	0.17
	Ranking	1.00	2.00	3.00
Water Use	Water use (Million Litres)	814.32	3,956.88	35,590.35
	Normalised Water Use	1.00	0.21	0.02
	Weight	0.20	0.20	0.20
	Water use Final Score	0.20	0.04	0.00
	Ranking	1.00	2.00	3.00
Land Use	Land Use (Acres)	6,543.00	7,158.00	12,182.00
	Normalised Land Use	1.00	0.91	0.54
	Weight	0.15	0.15	0.15
	Land Use Final Score	0.15	0.14	0.08
	Ranking	1.00	2.00	3.00
Bio-physical Impact	Bio-physical impact	6.06	7.14	11.70
	Normalised Bio-Physical Impact	1.00	0.85	0.52
	Weight	0.15	0.15	0.15
	Bio-physical Final Score	0.15	0.13	0.08
	Ranking	1.00	2.00	3.00
Climate Resilience	Climate Resilience	5.33	6.33	14.32
	Normalised Climate Resilience	0.37	0.44	1.00
	Weight	0.15	0.15	0.15
	Climate Resilience Final Score	0.06	0.07	0.15

Criteria		LCP	CO2	FRES
	Ranking	3.00	2.00	1.00
Job creation	Job Creation	737.76	863.76	1,330.48
	Normalised Jobs	0.55	0.65	1.00
	Weight	0.10	0.10	0.10
	Jobs Creation Final score	0.06	0.06	0.10
	Ranking	3.00	2.00	1.00
Construction ESIA Impact	Construction ESIA Impact	7.35	8.75	13.99
	Normalised Construction ESIA	1.00	0.84	0.53
	Weight	0.05	0.05	0.05
	Construction ESIA final score	0.05	0.04	0.03
	Ranking	1.00	2.00	3.00
Total MCA Scores and Ranking	Total Scores	0.86	0.67	0.61
	Final Ranking	1	2	3

Source: Mott MacDonald

9.3.2 Sensitivity Analysis

Four sensitivity analyses were undertaken in order to assess how the three scenarios rank under weights that place more importance on social and environmental criteria respectively. Two environmental and two social sensitivities were analysed. The detailed results from the sensitivity analysis are presented in Table I.6 - Table I.9 in the Appendix I.

For the environmental criteria sensitivities (columns 3 and 4 in Table 9.3), the weights of all four environmental criteria are increased to 20%, the economic and social weights are reduced, while the construction weight remains the unchanged. For environmental sensitivity 2, land-use for biomass production is considered to be positive. The rationale for this is that there is substantial fallow land due to the decline of the sugar industry, and a number of stakeholders commented that revitalising the old farmland and putting it under crop cultivation would have significant long-term benefits in terms of land preservation and food security.

For the two social criterion sensitivities (columns 5 and 6 in Table 9.3), the weight of job creation is increased from 10% to 25%, the weights of all the environmental criteria are reduced, the economic criterion is unchanged, and the construction criterion weighting is increased to 10%. As countries seek economic and social recovery after the global COVID-19 pandemic, job creation is a key economic and social priority for policy makers. For the social sensitivity 2, land use for biomass is also viewed as positive for similar reasons as stated above for the second environmental sensitivity.

For the environmental criterion sensitivities (columns 3 and 4), the weights of all four environmental criteria are increased to 20%, the economic and social weights are reduced, while the construction weight remains the unchanged. For environmental sensitivity 2, land use for biomass is also viewed as positive for similar reasons as stated above for the second social sensitivity.

Table 9.3: Weights in the stakeholders and sensitivity analysis

	Criteria	Stakeholders' weights (%)	Environmental Sensitivity 1 weights (%)	Environmental Sensitivity 2[6] weights (%)	Social sensitivity 1 weights (%)	Social sensitivity 2[6] weights (%)
1	Scenario cost	20	10	10	20	20
2	Land use	20	20	20	10	10
3	Water use	15	20	20	10	10
4	Bio-physical impacts	15	20	20	10	10
5	Climate resilience	15	20	20	15	15
6	Job creation	10	5	5	25	25
7	Construction ESIA impacts	5	5	5	10	10

Source: Mott MacDonald

Table 9.4 below presents the ranking of the base weighing and the four sensitivities. The MCA results show that the LCP scenario has the highest ranking in the base and all sensitivity cases except for social sensitivity 2. The FRES has the highest ranking if job creation is the most

[6] The only difference between environmental & social sensitivity 1 and 2 is how land is viewed, particularly fallow land. Land-use for biomass production is considered to be positive

important criterion to the decision makers, and land use for biofuel crop cultivation is viewed as a positive criterion. The CO2 scenario is never ranked the highest and has the second position only in the base case and when the four environmental criteria are given more importance than the other three criteria.

Table 9.4: Base and Sensitivity Ranking

Description of Base and Sensitivity	LCP	CO2	FRES
Base	1	2	3
Environmental Sensitivity 1	1	2	3
Environmental Sensitivity 2	1	3	2
Social Sensitivity 1	1	3	2
Social Sensitivity 2	2	3	1

Source: Mott MacDonald

9.4 Conclusions

The MCA has been carried out to evaluate a holistic ranking of generation planning scenarios, as Barbados transitions to a more sustainable electricity system. Based on the agreed criteria with the stakeholders, where scenario cost and land use are assigned the highest importance, the LCP scenario achieved the highest ranking with a total MCA score of 0.86, followed by the CO2 scenario with a score of 0.67, and finally the FRES with a score of 0.61. Therefore, the MCA has identified the LCP scenario as the best option for Barbados, based on the stakeholders' preferences.

The CO2 scenario ranked second in the stakeholders weighting and environmental sensitivity analysis. This gives an indication of how a policy designed to encourage RE integration and reduce carbon emissions will create additional jobs and a more climate resilient network, however the trade-off is having additional investments and increased impact on the environment

The FRES ranked third in the stakeholders weighing, and this is predominantly due to its comparatively higher land and water requirements for biofuel crop cultivation. On the other hand, from a predominantly social perspective and when land for biomass production is viewed as a positive for Barbados, the FRES ranked first because the biomass plants could potentially create up to 100 indirect jobs from the cultivation and logistics of biofuel crops.

The MCA process has highlighted the importance for policy-makers in Barbados to investigate inter-sectoral interactions and dependencies. The ranking of electricity planning scenarios is strongly influenced by the weightings of the different cross-sector criteria. Therefore, the planning for the electricity sector should not be undertaken in isolation, and its interactions with other sectors such as transport (EV), agriculture (biofuel crops), and tourism (cruise liners), should be assessed.

Recommendations

10 Recommendations

The following is a list of recommendations for action following this IRRP in support of its implementation and future IRRPs. The list is in a non-prioritised order developed in the course of undertaking this study.

10.1 Current electricity market context and diagnostic

- Where projects are delivered through IPPs, we would recommend a framework for competitive auctions which has seen great success in many jurisdictions all over the world in ensuring very good value for money renewable energy projects.

10.2 Demand Forecast

- There is uncertainty around the new electricity demand sectors, particularly in relation to EV uptake scenarios and CL electrification. More cross-sector collaboration needs to take place to define most likely scenarios, and data on EV uptake should be collected going forward to allow for more accurate EV forecasts in future;
- To unlock the benefits available from smart EV charging; some investments may be required to encourage consumers to work with the power system rather than against it. Smart controls on charging infrastructure would turn EVs into a significant source of flexibility, without even considering any Vehicle-to-Grid (V2G) technology. Overall, the near-term impact from EV charging on the power system is likely to be small due to the low level of EV penetration;
- The LINDA model has been significantly updated to provide a comprehensive demand forecast, and also account for newly electrified sectors such as EV and CLs. For future analysis following this IRRP, our recommendations for future updates to the LINDA model include:
  - Annual Growth Rates: The assumptions for annual growth rate of real GDP, electricity intensity, and residential demand are entered in the model as a constant for five years. This approach does not capture significant changes that could impact annual growth rates, and will require that care is taken in setting values for the first five-year block which in a year’s time will comprise both history and projection. We recommend breaking down the input for annual growth rates into one-year time steps to account for future changes in trends;
  - Hourly Load Forecast: With the proposed target for 100% RE supply in Barbados, we recommend forecasting hourly demand, which will be useful in the hourly dispatch planning of RE power plants, and thus ensure a stable power system. Hourly load can be forecasted based on the actual hourly load from the previous year, forecasted annual demand, and load profiles of the newly electrified sectors; EVs and CLs. Additionally, any major DSM initiatives such as time-of-use (ToU) tariffs proposed in later years could be included in forecasting the hourly load;
  - Electricity Prices: With the increasing uptake of solar water heating (40% of households) and roof-top solar PV (3.5% of electricity generated in 2019), some residential consumers are decreasing their consumption from the grid. With these options, and the feed-in-tariff available to consumers, changes in electricity prices could impact their electricity demand. We recommend examining the correlation between electricity price and demand. If there is a strong correlation, energy prices should be considered in the next update of the LINDA model

10.3 Resource Options Evaluation – Supply Options

- It is recommended that a census of available land for renewable energy development is carried out alongside an integrated town-planning, land-use, water, agriculture, and energy GIS study in order to allow planners in MESBE greater certainty around potential constraints to be able to make informed decisions around any trade-offs between sector developments that may arise in the future. An integrated study can identify synergies between different sectors with the objective of attaining objectives included in the Multi Criteria Assessment (MCA);
- A comprehensive data collection and yield assessment exercise should be carried out for renewable technology options, that uses high quality data collected from various sites in the country;
- In terms of RE resource data, we recommend the following:
  - Record and build a data base of windspeeds and solar irradiance as well as energy output of RE plants at a granular level over a period of at least one year at different locations on the island to be able to quantify the effects of power intermittency dispersion and times;
  - Note that the use of "granular level" referred to above implies minute-by-minute intervals at most with maximum, mean, minimum and standard deviation values available for each interval. It is noted that developers typically conduct measurement campaigns as part of their feasibility studies in order to understand the resource at their site in detail.
- Indigenous production of liquid biofuels (e.g., ethanol) could be explored, as an alternative option that would tackle the high costs associated with importing and could make these technologies economically feasible for Barbados;
- A biomass resource assessment and sustainability framework should be carried out to facilitate the targeted developments of biomass generation;
- An energy from waste resource assessment (linked to integrated waste management strategy) should be undertaken noting that waste avoidance is more sustainable than waste incineration, the latter still leading to carbon emissions from non-biogenic components of the waste (e.g., plastics made from fossil fuel);
- Emerging technologies should be monitored and assessed from time to time. For the current IRRP, ocean energy technologies such as off-shore wind and off-shore floating were found to be too speculative regarding their feasibility in Barbados and certainly not to be cost competitive with other available options. That is not to say thought that new technologies can provide opportunities in future.

10.4 Energy Storage Technology

- Whilst the technical and financial feasibility of HPS currently remains speculative, it is recommended that further feasibility studies are carried out to identify suitable sites and develop concepts that address potential risks and provide cost and size estimates on the basis of which system planning can be carried out by the MESBE;
- In terms of CAESs, their feasibility in Barbados remains speculative. It is recommended that further studies are carried out to identify suitable sites and develop concepts for which cost, and size estimates are developed on the basis of which system planning can be carried out by the MESBE. Should suitable underground storage exist, CAES has the potential to provide the longer duration storage at lower cost than additional Li-Ion batteries;
- The development of flow batteries should be monitored carefully as their track record and costs improve;
- Considering energy storage solutions, it is recommended that MESBE take a technology-agnostic view and compare future available options to get best value for money for the

specific application (bulk energy storage) as long as performance and risk profile of the technologies all meet the requirements. For system support applications, Li-Ion battery storage is currently the best available option due to its present unparalleled performance.

10.5 Generation Planning Study

- Capabilities in forecasting demand, RE generation output, and expected intermittency with high accuracy several days or longer into the future should be strengthened. This will become critical for security of supply and efficient system operation through optimising dispatch by using stochastic dispatch approaches. Forecasting will be required to prepare plant and manage BESSs' state-of-charge levels in advance of low sunshine or low wind periods;
- The feasibility of HPS as a storage candidate should be studied. In light of currently highly uncertain assumptions, we have not included this storage option in this IRRP. However, iterations of the IRRP can be carried out where different potential assumptions are tested to determine whether and at what maximum cost the technology could play a beneficial role. If indicative modelling results suggest that HPS is favourable even at expected high costs, a feasibility study should ascertain the feasibility, performance, cost, and environmental impact such that it can be considered a serious expansion option for future IRRPs;
- High granularity VRE production data across the island should be continuously and systematically collected, monitored, stored, and analysed together with details about weather conditions from all power stations in order to be able to quantify and estimate RE yields and intermittency now and in future. This is important for accurate reserve dimensioning, particularly for secondary reserve, which has been estimated for this study, but caveats remain due to the scarcity of data points. In this study, we have therefore taken what we believe to be a conservative approach. The outcome of the reserve dimensioning contributes to the BESS power capacity requirements (among other factors) and less uncertainty means lower risk to security of supply, higher planning certainty, and also has the potential to optimise (and potentially reduce) the required BESS deployment and therefore investment, costs, and tariffs;
- Periodically perform analysis of the effective load-carrying capacity of different generation for the future as well as re-evaluate the Capacity Reserve Margin (CRM) requirements. With system conditions changing significantly, the CRM requirements and also the de-rating (or "equivalent firm capacity") factors for each technology, particularly VRE and BESS also change dynamically. There are a number of factors, such as load profile, renewable energy profiles, generator reliability, and make-up of capacity mix at play. Increased deployment of BESS and the removal of aging plant leads to a higher system reliability for a given CRM. At the same time, increasing dependence on batteries for firming-up VRE decreases reliability due to duration limitations for a given CRM. We have calibrated the model for this IRRP to provide reliable results, but these may not hold true for future IRRPs;
- Technology capex and developments of load growth and other variables, such as fuel cost, policy, and IPP developments should be continuously monitored to keep the masterplan up to date within the context of very dynamic real-world developments. Stochastic optimisation can be a useful tool where one set of decisions is optimised relative to multiple scenarios of the (uncertain) future.
- Decarbonisation and the transition of increasing RES integration will most likely result in stranded assets such as gas storage and distribution infrastructures. The operators of these assets will either incur these costs or be compensated by the government. This is why it is important for the government to have policy mechanisms in which stranded asset costs are handled. Another option is to utilise some of these assets for Hydrogen in the future.

10.6 Transmission Planning Study

- A 20-year masterplan should not be used as a rigid template for the precise timing and implementation of transmission projects. Further, more detailed project-specific studies should be undertaken as each transmission project enters five-year and two-year project windows. Where transmission equipment is shown for a particular study year, e.g., 2025 or 2030, this does not mean that the equipment can only be installed in this year but provides an indication on when these projects should be considered for further investigation;
- As projects enter the five-year and two-year windows, the following further studies (not in the scope of the IRRP) should be undertaken:
    a. Site visits to ascertain space for substation, cable, and line works;
    b. Room in existing substations for busbar extensions, additional protection, and control equipment, etc.
    c. Environmental and Social constraints (ESIA constraints)
- Protection studies and grading are not included in the scope of work for this assignment. Further protection studies are recommended as new generation and BESS systems are implemented and fault levels change. More detailed protection analysis is recommended for islanding and re-synchronisation analysis;
- Harmonic studies may need to be considered as the penetration of harmonic producing VRE generation and BESS increases. Harmonics can be mitigated using harmonic filters however more detailed harmonic studies would be required as the system evolves. Further, the Barbados grid code and Power Purchase Agreements (PPAs) should be updated to include harmonic limits for future VRE power plants;
- More work is required to design the power system to be more resilient for extreme weather events. Electrical islanding is one method of ensuring that parts of the system can operate while other parts of the system are blacked out. For islanding to be effective, loads, and generation in islanding zones should be matched;
- Other resilience interventions should be investigated including raising or protecting power stations and transmission substations to be flood and storm resistant;
- Co-locating BESSs with utility scale solar PV plant and wind farms can reduce the investment required in transmission system capacity. Batteries can absorb excess generation in their charge cycles and discharge into the connected loads outside of their charge cycles thus balancing the VRE generation with load and reducing transmission usage;
- Re-purposing of existing synchronous generation to operate as SCOs should be investigated; this could decrease the cost of purchasing new SCOs. The re-purposing could investigate introducing clutches for emergency situations where the prime movers are required to provide back-up generation. The ability to switch back and forth automatically between active and re-active power mode provides benefits for system operation;
- State-of-the-art Energy Management Systems (EMSs) and telecommunications should be implemented for real-time monitoring and control of the system operation and integrate into the forecasting process.
- A study to introduce an Automatic Generator Control (AGC) system to the island should be undertaken.

10.7 Multi Criteria Assessment (MCA)

- The assumptions, parameters and weightings of the MCA should be updated regularly or in unison with the updating of the IRRP. An IRRP and MCA update is recommended at least every two years;

- A clean energy transition can be a significant driver for the island's economic development if managed correctly.
- The MCA developed for this IRRP will certainly stimulate a discussion among all stakeholders and further future refinement of the criteria, weights, and underlying assumptions would be expected to take place.
- We recommend an inter-sector working group to analyse and agree planning criteria and priorities.

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Appendices

A. Scope of Work for the Assignment

A.1 Scope of Work for the IRRP

The objective of this consultancy is to support the development of the Government of Barbados' (GoB's) IRRP within the framework of the GoB's BNEP 2019-2030. The implementation of this package of support is taking place over the short and medium-term and necessitates collaboration with MESBE's key energy stakeholders (e.g., BLPC, FTC, BREA, GEED, etc). It includes analyses, studies, and inputs designed to meet MESBE's needs for a comprehensive plan as well as align similar efforts among MESBE's mentioned key stakeholders. In order to achieve the objectives, the key outputs to be provided include [43]:

a. A diagnostic study of the challenges facing the electricity market in Barbados which could also provide inputs to develop an Integrated Resources and Resilience Plan (IRRP) – Activity A;
b. MESBE's IRRP for Barbados - Activity B;
c. A comprehensive assessment of the technical, institutional, and organizational capacity of MESBE to undertake its new planning function needs to be articulated, particularly as it relates to the IRRP and energy planning at large – Activity C;
d. A comprehensive assessment of the critical stakeholders and their related legislation to determine the level of compatibility with achieving the intended targets of the National Energy Policy 2019-2030;
e. A comprehensive capacity-building training plan and program for MESBE as it relates to the IRRP – Activity D;
f. Technical expertise/support to MESBE to strengthen information sharing with key energy stakeholders.

A.2 Scope of Activity A - Diagnostic Study

The scope of the Diagnostic study from the Terms of Reference (ToR) is included below for completeness. While we have covered all the scope items mentioned in the sections below, we have slightly restructured the sections in this Diagnostic Report for better flow and order of tasks.

A.2.1 Technical Document

A Technical Document providing an overview and diagnostic on the electricity sector of Barbados will be developed consisting of chapters that will provide an analysis of the current situation facing the electricity sector and prioritise interventions that could provide adequate solutions. The Technical Document will also provide relevant information for the development of the MESBE's IRRP. A description of these products is described as follows:

A.2.2 Section 1

This diagnosis will be based on current studies (from MESBE, IDB, and other key stakeholders) and consultations with key energy stakeholders in Barbados. The study will provide a comprehensive analysis of the current situation facing the energy sector describing both demand and supply side constraints and issues. This will include an analysis of the energy supply and demand of each energy resource and the final uses. The main topics to be covered are the following:

i. historical statistics of energy sources (primary energy supply and electricity generation) and imports and exports;
ii. current energy mix of the country;
iii. uses of fossil fuels by type, quantity, and sector (power, industrial, transport, commercial, residential, and others);
iv. identification of the main suppliers (countries/companies);
v. regulatory framework, and market structure;
vi. current investment trends in the current RE power market and how these trends impact the BNEP 2019-2030;
vii. load flow analysis and forecast

A.2.3 Outcome of Section 2

The outcome of this section should be the evaluation of the regulatory and institutional framework that enables the implementation of the right incentives to reduce cost of electricity to the final consumer.

A.2.4 Section 2

Section 2. The analysis will be based on public available information (e.g., National Energy Policy 2019-2030) and any information provided by the Client. The analysis will address main challenges facing the sector pointing to possible interventions that could enable a reduction in the price of electricity to businesses and consumers given the introduction of new low carbon energy sources, natural gas, and renewable energy), energy conservation, and energy efficiency measures. The study should identify challenges and propose high-level solutions to network issues and propose least cost measures to address identified constraints. The study should not only state the level of renewable energy that can be supported with the current grid configuration, but it should also propose, if required, upgrades to the grid to accommodate the level of RE contemplated in the BNEP 2019-2030, including a high-level budget for the cost of such upgrades. The diagnostic and overview will provide a focus, enabling the MESBE to identify priority interventions in the sector. The diagnostic will also review the Electric Light and Power Act (2013), highlighting the implications of a change in roles and responsibilities between the key energy stakeholders and the imminent changes in the licensing acts of various energy agencies.

A.2.5 Section 3

- **Section 3**. The Diagnostic will also include an Annex that will provide important information and the complete dataset used for the development of the MESBE's IRRP. This Annex will contain the following:
  i. Calculation of the most appropriate discount rate that should be used to determine the net present value (NPV) of future cash-flows concerning energy projects. This information will be a result of conversations with MESBE regarding current GOB's costs of equity and debt in relation to its proportion of the government budget structure. At a minimum the base assumptions for the model should be included and explained, including the technical assumptions about existing plant.
  ii. Current and projected exchange rate between national currency and US$, using approaches such as the Purchasing Power Parity (PPP), the relative economic strength, economic models, or time series models as well as economic criteria such as efficiency, opportunity cost and domestic resource costs.
  iii. Analysis of existing fuel resources in the country, addressing issues such as availability, calorific value, fuel costs projections, etc.

iv. Identification of existing renewable energy generation curtailment, additional reserves required, if any, and costs associated with it.

A.2.6 Findings of the Diagnostic Study

The consultant, in consultation with MESBE and IDB, may adapt the objectives in Activity B and Activity C considering the findings of the Diagnostic Study.

A.3 Activity B: MESBE's Integrated Resources and Resilience Plan

Activity B will develop through the MESBE and with consultations from key energy sector stakeholders, necessary inputs for the development of an Integrated Resources and Resilience Plan within the framework of the BNEP. The consultant will give options on how to develop and codify the IRRP planning process, identifying key responsibilities, target dates (timelines) for the various activities, criteria to be met and standards to which deliverables must satisfy. The inputs to the IRRP will incorporate answers to concerns such as equity, loss reduction, environmental protection, reliability, and other country-specific goals as determined in the consultations of targeted stakeholders.

The elements that will be considered in the inputs to the IRRP and the proposed approach are described further below.

A.3.1 Definition of the objectives and scope of the plans.

The IRRP aims to identify the best mix of supply and demand-side options that minimize generation costs in the planning period (next 10 years). The proposed inputs to the IRRP will take into account additional objectives set out together with the target stakeholders during the consultations in Activity A. To reflect a realistic near-term development of the energy sector, the consultant will review the electricity generation studies and expansion plan prepared by BLPC and the GOB as inputs.

A.3.2 Base-year data collection.

Information on the requirement of electricity services, population, energy consumption, and production levels in the initial period will be collected based on energy-service or by user category. To provide a well-documented and objective picture, this task will make use of publicly available data. In addition, efforts will be made to ensure that all data used are comprehensive and consistent. Augmenting this effort will be on site asset inspections and stakeholder meetings to determine asset condition which informs current asset status relative to industry standards. The results of this asset assessment will be a report on current asset condition, including potential for life extension upgrades and plant retirement, location, and potential for future asset location around the island.

Deliverable

Presentation of proposed objectives and current asset condition with benchmark to other regional and small island developing states utilities. At this time, the objectives and outline of the inputs to the MESBE's IRRP final report will be approved by the MESBE within 20-25 days of presentation. The Presentation will include metrics to quantify social costs, rates impacts, and production costs associated with each alternative scenario of future growth.

A.3.3 Input 1: Demand forecasting and estimation of future requirements.

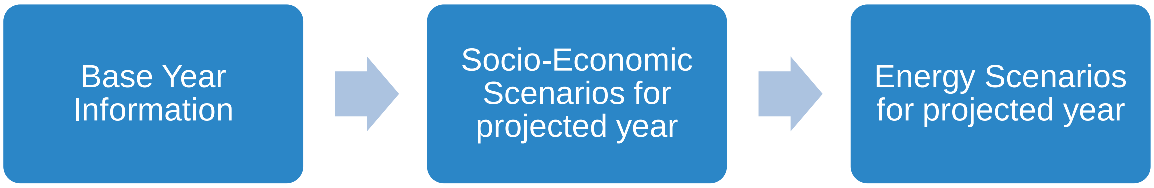
The future requirement of electricity services can be estimated from the base-year information and changes expected in different scenarios.

A scenario analysis will compare options to provide a given level of energy services. The consultant will consider three end-use scenarios:

- A baseline scenario (which considers increasing load along with improvements in end-use efficiencies and loss reduction measures and;
- A high load scenario (which assumes constant the current levels of energy efficiency and increasing load).
- A low load scenario (which considers a decreasing load with improvements in end-use efficiencies)

Scenarios can be derived for one end-use measure or a set of improvements in several end-uses and sectors (residential, commercial, and industrial). Demand Side management should be treated as a sensitivity.

Figure A.1: Projecting energy demand scenarios



Deliverable

Presentation of initial results and approval by the IDB within 20 days.

A.3.4 Input 2: Identification of the demand side options to service the future requirements as well as supply options (including Renewable generation).

After the electricity demand forecast, all demand and supply side options available to Barbados need to be identified. Generation improvements in current facilities and different technologies to be considered including renewable generation, transmission and distribution infrastructure upgrading and development, energy efficiency measures and energy storage technologies need to be identified so that they can compete for inclusion in the least-cost mix. It will also be necessary to consider fuels and resources available from domestic sources and imports, as well as related infrastructure.

The consultant will identify and propose solutions to dispatch and network issues and propose least cost measures to address identified constraints based on detailed circuit analysis. The study should not only state the likely level of renewable energy that can be supported with the current grid configuration, but also if it is required, propose potential upgrades to accommodate the level of renewable energy contemplated in the Vision 2030 (100%), including a high-level budget for the cost of such upgrades to be developed in collaboration with BLPC. The use of storage and other non-wire solutions to offer savings or deferrals to new investment should also be assessed.

The extent and cost of the required additional transmission and distribution network development to accommodate the renewable development should be considered and ranked as part of a least cost renewable energy portfolio over a range of likely cost scenarios for oil fuel, carbon, renewable, technologies (including smart technologies) and network reinforcement.

For the supply side, different conventional generation technologies will be considered as candidate plants, such as low speed diesels, medium speed diesels, steam turbines, Simple-Cycle Gas Turbines (SCGT) and Combined-Cycle Gas Turbines (CCGT) etc as peaking/backup capacity. The study should include sensitivity analysis to address the impacts of changes in input parameters, e.g., fuel price, demand growth, technology CAPEX cost, DSM programmes as demand modifiers, and DSM measures influencing uptake such as incentives and behaviour modifiers.

The consultant will consider three (3) scenarios for the development of Renewable generation:

- a high renewables scenario (utilizing high firm capacity renewables),
- a high renewables scenario (utilizing high intermittent capacity renewables),
- a low renewables scenario. (freely choosing between firm RE, intermittent RE, conventional sources and storage,

The development of renewable generation is determined exogenously through a set of assumptions for its development over the considered period, focusing on commercially and technically proven technologies. The consultant will assess the development of the following Renewable generation supply options if applicable:

- Biomass (centralized and distributed);
- Solar PV (centralized and distributed);
- Concentrated solar PV;
- Wind (onshore and offshore);
- OTEC; and other suitable ocean energy technologies;
- Waste-to-energy;

The consultant will also incorporate existing plans for the development of Cogeneration.

Additionally, the consultant will rely on existing network development plans and studies related to transmission and distribution network reinforcements in the Barbadian system. In order to identify transmission and distribution capacity needs, the consultant will assess endogenously the need to reinforce interconnections between regions within the transmission system, based on a simplified approach to model the existing high voltage transmission system.

Demand Side Management (DSM) programs include both energy efficiency and peak reduction. To that extent, Demand Side Management programs can impact load forecasts and provide cost saving efficiencies. The consultant will conduct a preliminary assessment of DSM program potential for Barbados indicating some likely successful targets for residential DSM program savings. Targets of these programs could be the following:

- Residential refrigeration.
- Residential lighting.
- Solar water heater retrofits.
- Water heater equipment.
- High Efficiency Cooling.
- For Commercial and Industrial customers, introduce them into efficiency markets through energy audits.

The consultant will also consider other incentives from a monitoring and billing perspective that can influence DSM e.g., time of day billing, as well as the impact of electrification of the transportation sector on energy efficiency, load forecasts and peak reduction.

Furthermore, the feasibility of storage technologies will also be assessed with a focus on the ratio between their power and energy rating and round-cycle efficiency. Two different types of storage technologies will be considered:

- **Large scale storage** – typically connected to the transmission system with similar characteristics as traditional pump storage, with an efficiency of around 75% and several hours of discharge duration.
- **Small scale storage** – new storage technologies, such as batteries for instance.

The consultant shall include in this study the feasibility of a more decentralized architecture i.e., micro grids with smaller storage requirements per serving area against the larger centralize large scale storage solutions, inclusive of the reduction in transmission losses and improvement in resilience.

Deliverable

Presentation on Resource Options to meet load requirements will be approved within 20 days. Approval by the IDB for the Supply Alternatives, Demand Side Management/Energy Efficiency Programs, Loss Reduction, and Transmission and Distribution Network future state improvements is required. Storage alternatives and configurations will be approved as well.

A.3.5 Evaluation of supply options and estimation of the costs and savings of delivering electricity through the considered options.

The costs per unit (usually the annualized life cycle cost7 or the economic levelized costs of electricity) of electricity either delivered or saved, through each technologically feasible option will be calculated, considering emissions costs, if any, of generating electricity, and potential uncertainties such as the likely range of fuel costs and different capacity factors. An assumed value of CO2 emissions should be stated for fossil-based generation, and the levelized cost of the different renewable technologies should include the opportunity cost of state land and transmission modifications to ensure a reliable supply. The costs associated with the provisions of reserve fossil fuel units for extenuating circumstances will also be calculated.

The analysis will also consider transmission and distribution costs, including loss reduction measures, as well as the costs associated with the communication infrastructure and architecture to support next generation real time services and automation including network self-healing and reconfiguration (smarter grid). Investment needed to reinforce the transmission system will be based on specific costs per MW and per km for the additional capacity determined previously within the transmission infrastructure upgrading and development assessment. For distribution reinforcement costs, the consultant will assess the level of investment needed based on publicly available sources and expertise related to this subject. The study should rank with supporting evidence for a Barbados specific case, the available least cost renewable energy portfolio over a range of likely cost scenarios for fuel, low carbon, renewable technologies, and network reinforcement.

In order to reduce and/or change the timing of electricity use, an analysis of DSM options will be carried out, considering categories such as incentives to encourage efficiency in electricity use, higher-efficiency technologies, fuel-switching technologies, and load management measures. These DSM options will be quantitatively and qualitatively analysed and narrowed through a “cost of saved energy” approach and must include a weighted factor for the total impact of the potential efficiency measure.

All of these alternatives will be assessed by a commercially available software program, whose file type is compatible with BLPC and MESBE, to conduct impact analysis of future scenarios. The Consultant will incorporate production costing techniques to assess both long and short-term impacts. Rates and financial condition of the utility will be assessed for each future state and various scenarios. Shadow costs should be included in the analysis to determine social/economic costs and benefit impact to be in alignment with the national perspective.

Financing for each technology considered will create impacts on the utility financial status and must be considered. It is assumed that no more than 20-25 future state simulations will be defined. Periodic progress reports on the assessments will be provided. A draft and final report of MESBE's IRRP is contemplated.

A.4 Activity C: Comprehensive Institutional Assessment of MESBE and Capacity Building Plan/Program.

After completion of Activity B, Activity C will assist all critical institutions in strengthening their institutional, regulatory, human, financial, and organizational structure to enable the implementation of the IRRP and other energy planning responsibilities. The consultant will undertake an assessment of the current energy planning modelling tools, systems and practices within all critical institutions and make recommendations for appropriate best practices and technologies, including software. The consultant will conduct a comprehensive assessment of the organization, institutional and technical capacity of all institutions to undertake its new planning function, focusing in major part on the implementation of the IRRP and associated energy planning roles. The consultant will identify institutional and capacity gaps and make recommendations as necessary. After consultation with MESBE and the key energy sector stakeholders, the consultant will develop a comprehensive capacity building training Program and Plan.

To develop this activity, the consultant will review the outputs of previous capacity building consultancies, which will be provided, before field work (staying up to a week) with MESBE to assess its capabilities, and will issue a report over this issue with the findings.

A.5 Activity D: Support to knowledge exchange activities between MESBE and its key energy stakeholders as it relates to the IRRP and associated sector planning.

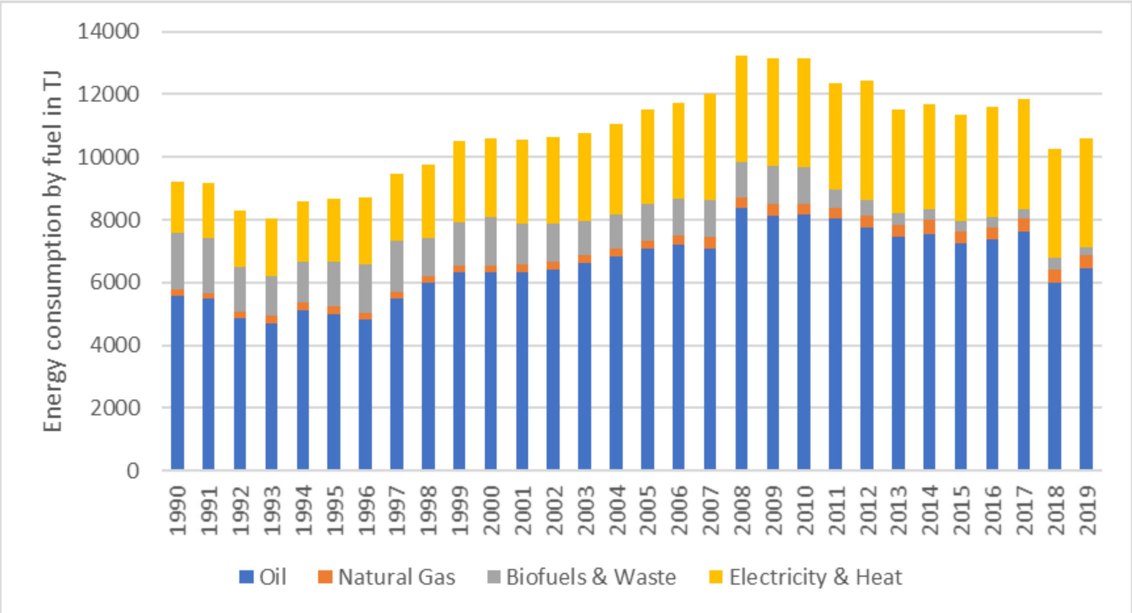
After completion of Activity C, Activity D will provide technical assistance to enable MESBE to meet its bilateral energy planning commitments and to help the Ministry undertake timely decision-making regarding IRRP and associated planning initiatives. For example, these studies/assessments can provide inputs to energy planning related to natural gas agreements, Power Purchase Agreements (PPAs), transmission and distribution grid reinforcement, and regional energy integration issues, and capacity building tools etc. Technical assistance in the form of resident and or / non-resident consultancy may be required that will provide timely expertise inputs and review. At the end of the consultancy, all the stakeholders should be fully briefed to efficiently support the various timelines and function to be performed.

B. Market Context

B.1 Energy use by fuel

Figure B.2 and Figure B.3 show the split in final energy use by fuel type in absolute values and shares, respectively[8]. This shows total final energy consumption increasing from 1993 to 2009, with oil, gas, and electricity use increasing, with only biomass falling slightly over this time. From 2009 final energy consumption, initially plateaued and then fell slowly to 2017 and then has fallen more sharply in 2018 and 2019. Over this whole period, oil products have been the dominant energy type with a share hovering around 60%. The figures show oil use dipped in 2018 (by 22% on the previous year) – largely as diesel consumption fell – before a modest recovery. Gas's share of the total has also been fairly stable, at a much lower level of 2-3.5%. The main shift in the fuel mix has been a reduction in bioenergy and waste use from about 20% of total final energy use in 1990 to around 10% in 2007 and 2% in 2019. As mentioned above this reduction in bio-energy use reflects the decline in the sugar industry, which mean the by-products/residues were no longer being produced. This decline in bio-energy use has been largely offset by an increase in electricity and heat[9] from 18% in 1990 to 33% in 2019. This reflects structural economic shifts rather than direct substitution [45].

Figure B.2: Final energy use by fuel types in TJ: 1990 to 2019

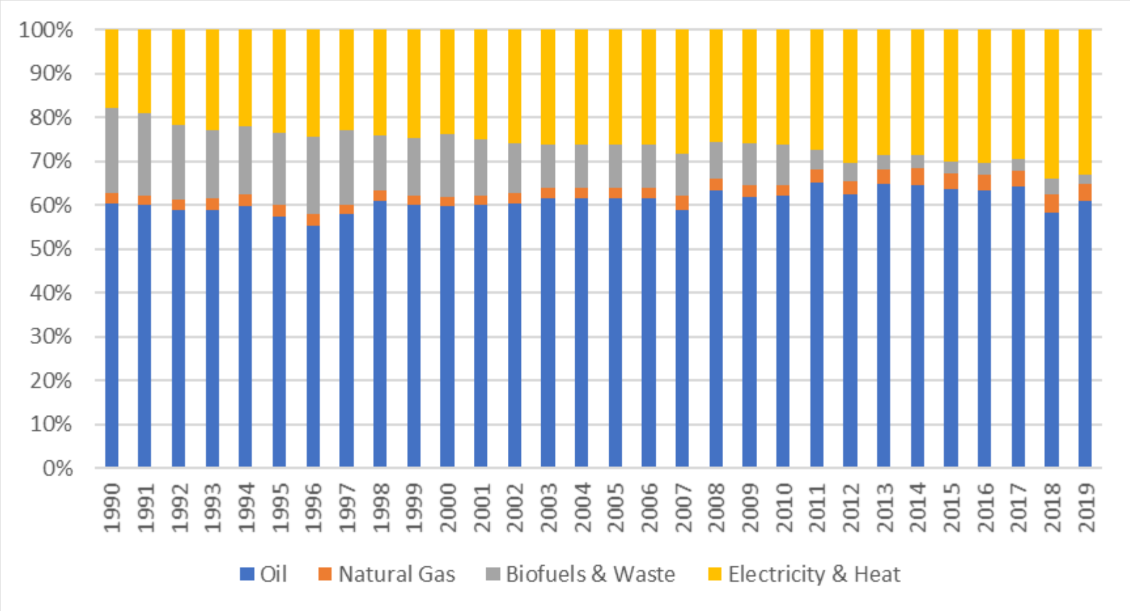


Source: UN Energy Statistics [45] and Barbados Statistical Service

[8] Note that it is common practice among some statistical bodies to count electricity and heat as "fuel". This is the approach of the UN statistics where this data was sourced. The UN data also lumps electricity with heat, where heat includes distributed heat and solar water heating.

[9] Heat includes solar water heating.

Figure B.3: Evolution of breakdown of final energy use by fuel type: 1990 to 2019



Source: UN Energy Statistics [45] and Barbados Statistical Service

B.2 Energy use by sector

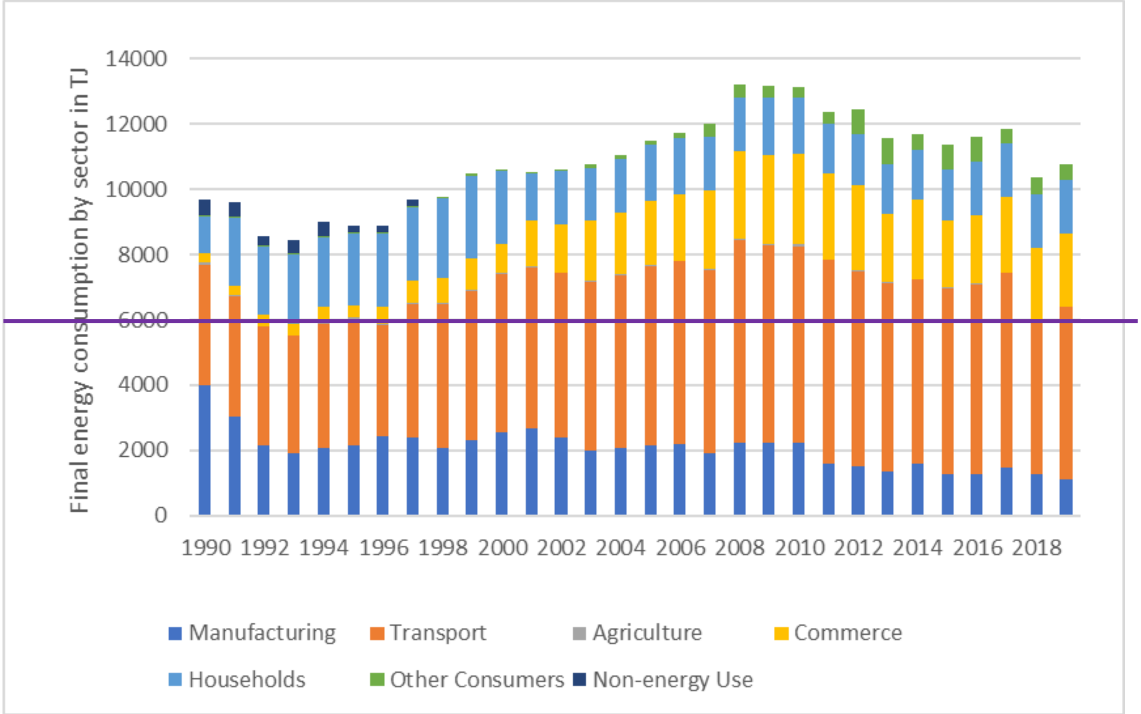
The shift in fuel mix in final energy use has been matched by significant shifts in the end user mix as shown in Figure B.4 and Figure B.5 below, which present absolute use levels and shares, respectively. The main features in this end user mix are the relative decline of manufacturing (industrial) and household (residential) demand at the expense of increasing commerce (commercial) and transport demand.

Transport is currently the largest end user. Its absolute energy use grew steadily from 1996 to 2008, after which it has plateaued. Over this period transport's share in total use has increased from 38% in 1990 to about 50% in 2017. In 2018 transport energy fell markedly but then in 2019 it saw a strong uptick which would be expected to be caused by changes in economic activity. Examination of the energy balances shows that it was diesel use which fell in 2018, and this could be linked to reduced economic activity in 2018 [45].

The commercial sector had seen strong growth from 1990 to 2007, a level which it broadly maintained until 2017 after which its share has fallen sharply. Commercial's share of total final energy increased from 3% in 1990 to 20% in 2007, a level which it has broadly maintained since then.

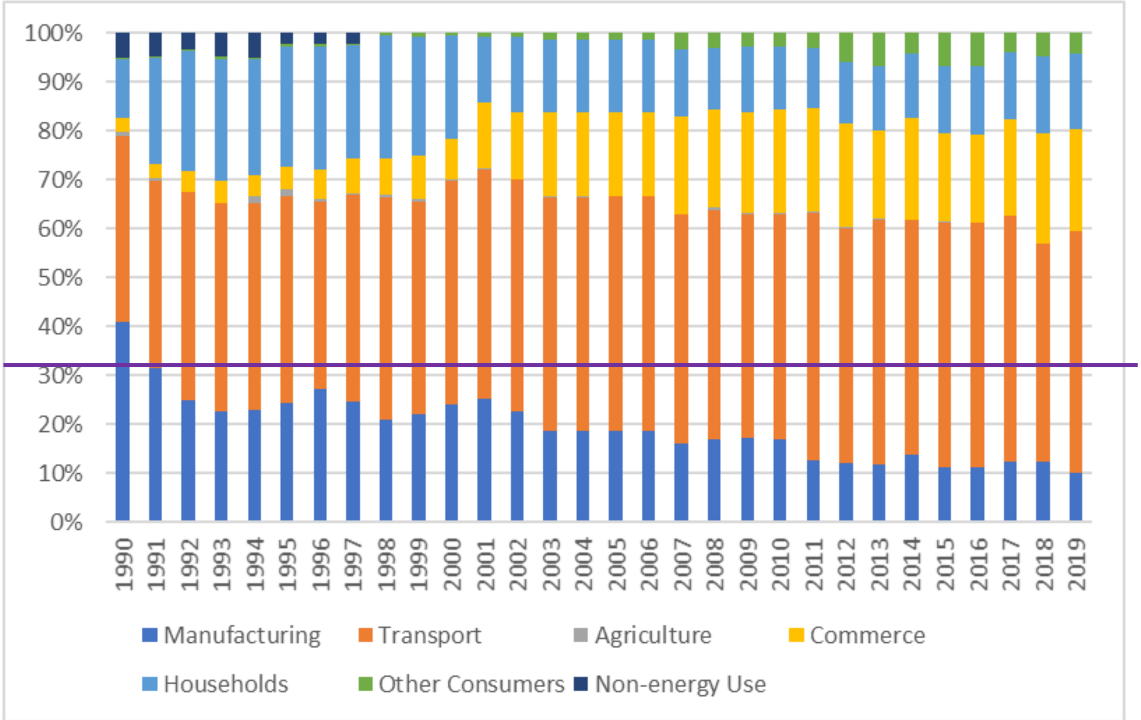
Residential is the third largest user group having recently overtaken industrial. Excluding 1990, the trend as shown in Figure B.6 has been one of slowly rising residential use up until 1999, after which there was a big drop with energy use plateauing from then on. The drop in residential consumption in 2000-2001 is coincident with a short economic downturn (-2.3% in 2001) but reflect other factors such as switch to higher efficiency lighting, uptake of solar water heaters – since demand did not rebound as the economy recovered. Overall residential energy share increased from 22% in 1991 to hit 25% in the late 1990s before slipping to 12-13% in 2008-2014 and then recovering to 15-16% in 2018-2019 [45].

Figure B.4: Final energy use by sector in TJ: 1990 to 2019



Source: UN Energy Statistics [45] and Barbados Statistical Service

Figure B.5: Breakdown of final energy use by sector in %: 1990 to 2019

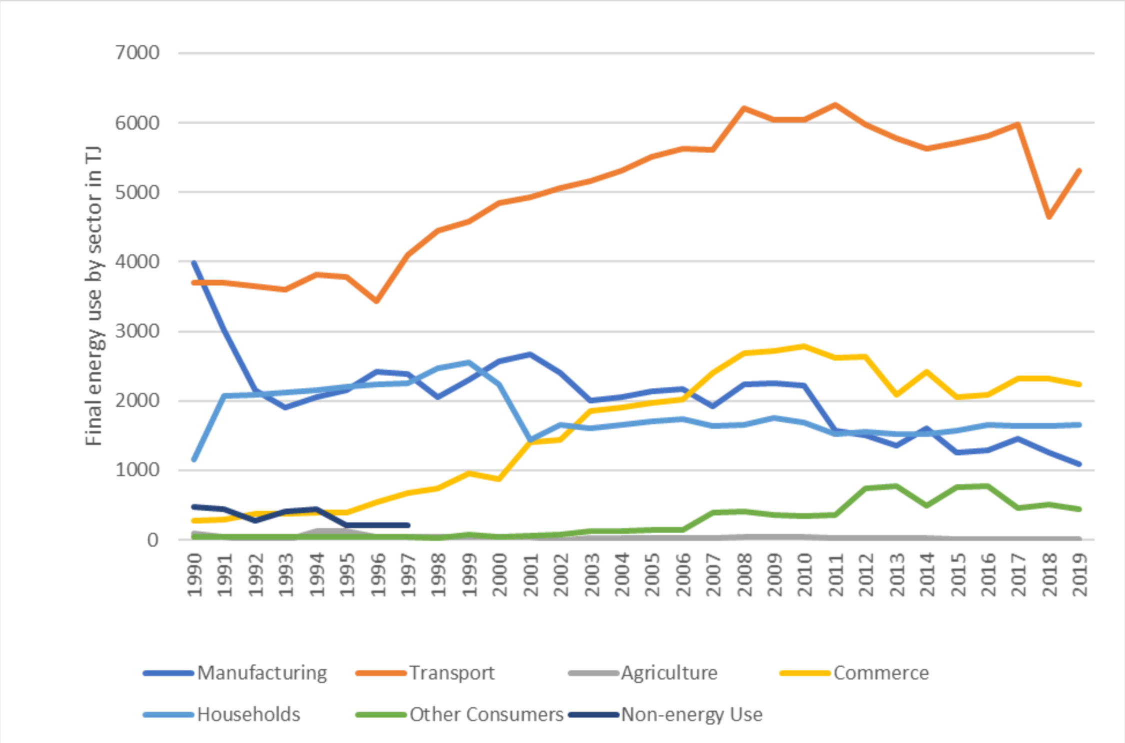


Source: UN Energy Statistics [45] and Barbados Statistical Service

Manufacturing has seen the most marked change with absolute consumption falling by 60% between 1990 and 2019 and its share in total final energy use falling from 41% to 12%. This reduction in industrial energy use reflects the decline in industrial production and a shift towards lower energy intensity activities.

The "Other Consumers" sector had seen a rising trend in consumption from 2007 to 2016, but this appears to have faltered in recent years. UN Statistics [45] defines the other sectors as those not included in the other defined sectors. It is unclear what this is in Barbados and it is a puzzle in that it has only been significant from 2007. In different jurisdictions this might include street lighting, construction, and telecoms utilities use but these existed prior to 2007. One possibility is that this might have included energy used in Bitcoin mining. Another possibility is that it reflects various transformation losses in the system. In 2019, this "Other Consumers" sector use accounted for 4% of total energy use.

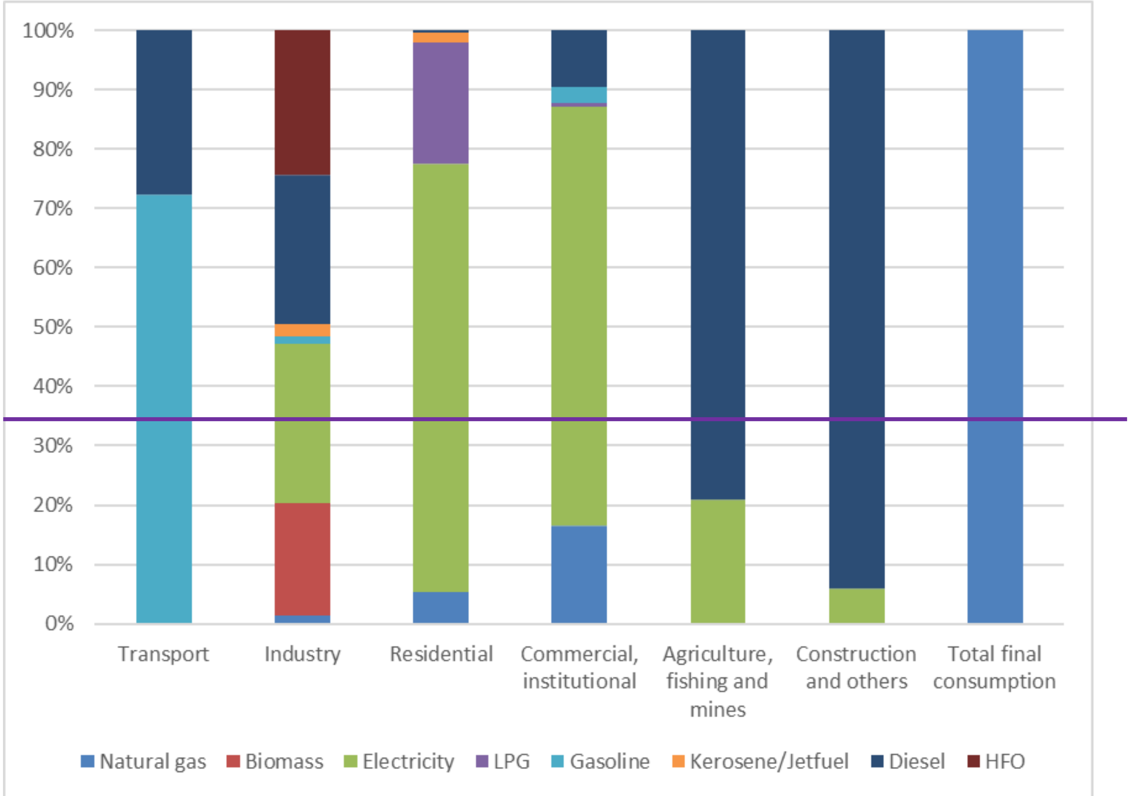
Figure B.6: Energy sector usage trends 1990 to 2019



Source: UN Energy Statistics [45] and Barbados Statistical Services

We present a few final charts and table which summarise the current 2019 energy balance. Figure B.7 shows the shares of fuels and electricity in end user demand in 2019. This shows that most sectors are dominated by one energy carrier – transport, agriculture, and construction by oil products, while residential, commercial, and institutional are dominated by electricity, with a small amount of oil products and natural gas. These are typical use patterns in an energy economy with no significant pace heating requirements. The industrial sector by contrast has a more diversified mix of energy supplies, with oil accounting for half of its use, with the balance being split 60:40 between electricity and biomass. Again, this is fairly typical split, with low gas share explained by limited supply of natural gas and the significant biomass share explained by the importance of the sugar/rum industries.

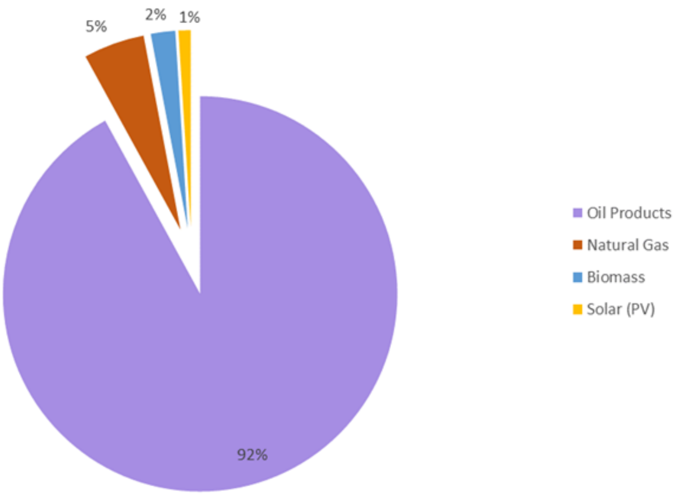
Figure B.7: Shares of different fuels in end user demand in 2019



Source: Barbados Statistical Service

The sectors show a diversity of supply pattern, but Barbados' primary energy use shows the dominance of oil products, which accounts for 92% of the total – see Figure B.8 Natural gas accounts for about 5% of primary energy use, with renewables meeting just 3%.

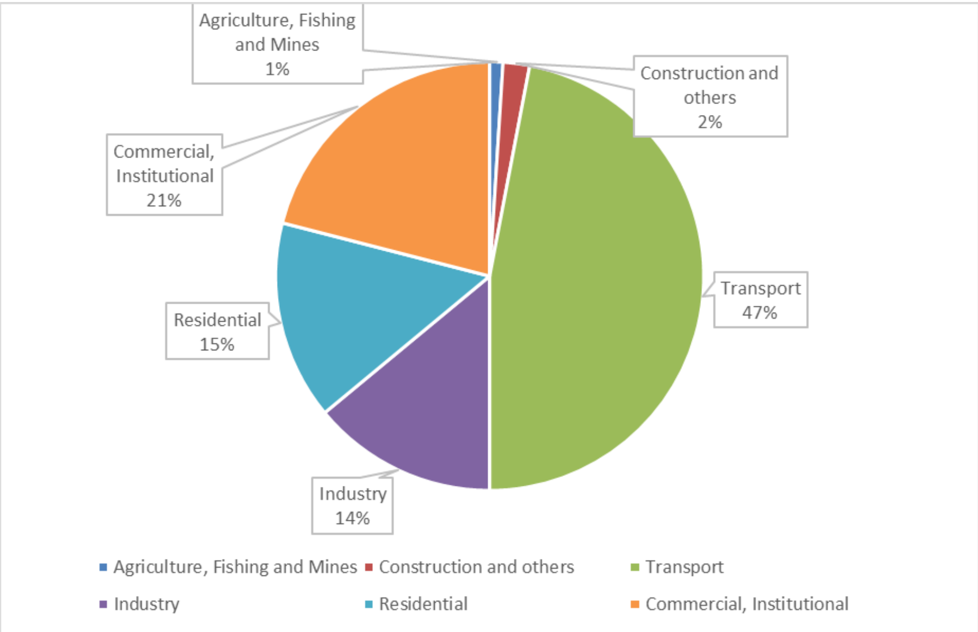
Figure B.8: Shares of primary energy by fuel type in 2019



Source: Barbados Statistical Service

Figure B.9 shows the breakdown shows the breakdown of final energy use by sector in 2019. This shows the dominance of the transport sector (accounting for 47%) – which here just relates to road transport and so excludes both aviation and shipping, both of which are significant in Barbados. The commercial and institutional sector – which includes the tourism activities – is the next biggest sector accounting for 21% of final energy use. The residential and industrial sectors account for most of the remainder with about 15% each.

Figure B.9: Breakdown of final energy use by sector in 2019



Source: Barbados Statistical Service

Drilling down into the mix of oil use shows a broad range of oil products are used ranging from heavy fuel oil (HFO) through the middle distillate products (diesel and kerosene) to the lighter products of gasoline and finally LPG. HFO is the number one oil product (at 36% of total oil use), with this being largely accounted for by power generation, while kerosene/jet fuel, and gasoline both account for about 22%, mainly in power generation and transport, respectively – see Table B.1.

Table B.1: Oil consumption by product in 2019

Type of Oil	Oil use in GWh	Oil use in kt oil equivalent	Oil consumption %	Main use sector
Heavy fuel oil	1,669	143.5	36	Power generation
Gasoline	1,063	91.4	23	Transport
Kerosene/jet fuel	998	85.8	22	Power generation
Diesel	751	64.6	16	Transport
LPG	102	8.8	2	Residential
Total	4,584	394.1	100	

Source: Barbados Statistical Service

B.3 Challenges in the current electricity sector and possible solutions

Key challenges comprise inter alia the following:

Table B.2: Challenges and solutions in the current electricity sector

No.	Challenge	Possible Solutions/Mitigations
1	**Technical/Reliability/Operational**	
1.1	Insufficient system reserve (e.g., 2-day system blackout in 2019)	Fast-ramping thermal plant (biofuels if necessary) and energy storage, possibly Battery Energy Storage Systems (BESSs) as these can be commissioned in under a year
1.2	Maintaining (or increasing) energy supply reliability in a situation where a high share of future generation is asynchronous	Same as above but with synchronous condensers (SCOs) added
1.3	Diversification of generation technologies	Incentives and policy direction
1.4	Insufficient penetration of distributed generation and storage	Attractive distributed generation and storage tariffs and smart systems for the TSO to make use of the distributed storage when required
1.5	Lack of synchronous electricity storage such as Hydro Pumped Storage (HPS) and Compressed Air Energy Storage (CAES)	Commission HPS and CAES feasibility studies specifically at geological and geotechnical issues
1.6	Lack of long-term storage (days, weeks, and months)	Commission hydrogen feasibility studies
1.4	Lack of sophisticated weather and RE forecasting system	TSO to implement a weather forecast system
1.5	Shortage of “smart” systems such as air-conditioner (A/C) and water heating controls for system stability reasons	Commission a smart system study
1.6	No smart EV charging/discharging systems for system stability reasons	Ensure that EV solutions come with smart systems linkable to the TSO
1.7	Required back-up of electricity systems for key functions as BWA desalination plants, hospitals, etc.	Commission a back-up power study. Options could include Internal Combustion Engines (ICES) running on biofuels or BESSs.
1.8	Insufficient system resilience due to:	
1.8.1	Lack of sub-system Islanding design with re-synchronisation capability of the sub-islands	Commission an islanding and islanding protection study
1.8.2	Overhead lines (OHLs) which are susceptible to extreme weather events	Replace OHLs with Underground Cables (UGCs).
1.8.3	Lack of operating reserve	As in 1.1 above.
2	**Land**	
2.1	Balancing competing uses for land given that renewable energy generation has a high land take	Commission an integrated town-planning, land-use, water, agriculture, and energy GIS study
3	**Fiscal and forex outflows**	
3.1	Large outflow of forex for oil products in the power generating sector	Diversify to RE generation and BESS and other energy storage technologies
3.2	Controlling investment costs and impact on end-user bills	RE and BESS costs are continually dropping so increased RE will decrease tariffs and distributed generation will decrease customer electricity costs
4	**Environmental**	
4.1	Achieving high levels of decarbonisation in the energy system	Diversify to RE generation and BESS and other energy storage technologies

No.	Challenge	Possible Solutions/Mitigations
4.2	Mitigating environmental and visual impacts of high levels of renewable generation	Use of low-grade agricultural land, use of non-categorised land and good ESIA guidelines for RE projects
4.3	Mitigating the impact of the cruise liners on energy use and emissions	Use of RE to electrify cruise liners while in port
5	**Socio-economic challenges**	
5.1	Balancing the social-economic benefits, e.g., of supporting the sugar cane sector through using local biomass	Commission an indigenous bio-fuels industry study
5.2	Insufficient enfranchisement of citizens	Tariff and financial incentives for distributed generation and mechanisms for shareholding in utility scale projects
5.3	Insufficient education and marketing of the benefits of customer RE and storage	Improved marketing possibly and incorporation into school and university curricula
6	**Market/regulatory**	
6.1	Lack of market design, regulatory and legal framework for a transparent and fair RE industry (leading to unsolicited RE bids)	Expedite activities in progress to formalise the RE IPP industry, and the unbundling of the vertically integrated industry
6.2	Access by the MESBE to sufficient network data and other data to create a "fair playing field"	MESBE to take on GIS staff and improve data gathering and processing
7	**Capacity and Resources challenges**	
7.1	Capability of MESBE to undertake IRRP and transmission studies	MESBE to take on qualified and experienced staff to conduct generation and transmission expansion studies
7.2	Lack skill in large bioenergy, on-shore wind, and off-shore wind generation projects	Improve university and tertiary curricula and temporary contracting of international experts or consultants
8	**Cost**	
8.1	The high costs of Barbados electricity are a result of fluctuating and high international oil prices	Diversification of generation, increased distributed generation and energy storage
9	**Energy Diversity**	
9.1	From the Sankey diagrams presented above, it can be seen that Barbados is almost entirely dependent on imported fossil fuels for its energy requirements	Diversification of energy as described above

Source: Mott MacDonald

C. Asset Assessment

C.1 Steam Turbines

C.1.1 General

Applications and output range

Steam turbines were originally developed in the early twentieth century and quickly replaced reciprocating steam engines because of their more compact size and their ability to produce much greater energy outputs. The combination of steam boiler and steam turbine soon became the preferred prime mover for large oil- or gas-fired stationary power generation applications and remained so until the more efficient combined-cycle gas turbine became available around 1950. A very large number of steam boiler and steam turbine power plants are still in use around the world and are often referred to as “conventional” power plants.

In a steam turbine, high pressure steam is passed over a series of blades attached to a turbine, and the pressure and velocity of the steam causes the shaft to rotate. In a power station, the turbine shaft is attached to the rotor of an electric generator, and the rotation of this rotor causes electric energy to be produced. The steam leaves the turbine at low pressure and is condensed before being returned to the boiler.

Steam turbines are available in a wide range of sizes, and units of more than 1500 MW are now available.

Almost all of the coal-fired power plants now in service are based on the “conventional” power plant technology. Due to their lower efficiency and higher capital cost, they are however no longer favoured for oil- or gas-burning applications.

Fuel

Steam boilers can operate on very wide range of fuel, including coal, peat, heavy oils wood and other renewable fuels as well as refuse-derived fuels and other combustible waste materials. Boilers designed for liquid fuels cannot however be used for burning solid fuels.

Performance

Conventional steam power plants normally achieve thermal efficiencies of 30% to 40%, depending on the steam pressure and the number of pressure and reheat stages in the boiler and the degree of pre-heating of the combustion air and feedwater.

The efficiency drops off steadily as the load is reduced and reaches about 30% at 25% load.

Conventional steam power plants can operate over a wide range of power outputs but are often restricted to outputs above 50% because of the increase in emissions when the output is below this level.

Because of the time taken to bring the water in the boiler up to boiling point and from there up to operating temperature and pressure, conventional steam plants are very slow to start up. Starting from cold, synchronising can normally be achieved in about 90 minutes, while if the boiler is pre-heated synchronising can usually be achieved in about 30 minutes. After synchronising, a further significant period is required to reach full output.

Conventional steam power plants also have low ramp rates and, when operating stably, can vary their load by no more than about 5% per minute.

For the above reasons, conventional steam power plants are not suitable for frequent starting and stopping and are used mainly for baseload applications.

Emissions from conventional power plants depend on the fuel used, and a range of technologies is available to reduce the levels of pollutants emitted to the atmosphere.

Construction

Construction costs for conventional power plants up to 30 MW are about 2200 USD/kW and for up to 200 MW are about 1800 USD/kW for a typical project. Costs will vary depending on the scope of works, location, appetite of the contractors and ground conditions.

Construction times (from notice to proceed to commercial operation) for steam power plants vary widely but are typically between 1.5 and 3 years.

Operation and maintenance

Conventional steam power plants generally have a good reliability record, with equivalent forced outage rates (EFOR) around 2%.

Care is however required specially to protect the boiler tubes from corrosion, and breakdowns can lead to long outages and expensive repairs.

They are comparatively reasonably complex to operate – particularly due to the need to closely control the chemistry of the boiler water – and remote/unmanned operation is not normally possible.

Variable O&M costs are in the region of three to five USD/MW and fixed O&M costs in the region of 30 USD/kW.

Steam power plants can be expected to operate successfully for up to 50 years, assuming overhauls are carried out in line with the manufacturer’s recommendations.

C.1.2 Unit S1 and S2 Information

Table C. below presents key information on the units as presented in the Barbados Plexos model obtained from BLPC. Steam units S1 and S2 are rated at 17 MW.

These units are must-run units, i.e., they operate as baseload plant due to their inflexibility. Minimum loading is just over 11 MW, which would require 6 hours to reach during a warm start and 14 hours during a cold start. Their ramp rate is 5 MW/min, which allows them to be reasonably flexible during operation; however, their inability to perform start and stop cycling as well as the high minimum stable generation level make them unsuitable for operation within a system with high penetration of variable renewable energy.

These units are 44 years old and are due to retire earliest by the end of this year or latest end of 2026. They have very high forced outage and maintenance rates, meaning the units have a very low reliability compared to newer well-maintained units.

Breakdowns of boilers are commonly due to corrosion of the boiler tubes, which is expensive and time-consuming to repair.

This efficiency is within the range we would expect for units of this type and age, but the fixed and variable operating and maintenance costs are greater than what would be expected for a more modern plant. These units are very expensive to operate because of their relatively low efficiency to be in regular use however their inflexibility also does not allow them to be suitable peaking plant.

There is the option to replace HFO with liquid biofuels by incorporating suitable changes in boiler burners. However, with the low fuel efficiency (typical plants of this size operate with a fuel efficiency of 25-35%), age, high operating and maintenance costs and a possible derating from the switch to biofuels, it is unlikely that continued operation of these units would be economically favourable.

Table C.1: Key Information on S1 and S2

Property	Units	S1	S2
Units	-	1	1
Max Capacity	MW	20	20
Min Stable Level	MW	11.2	11.2
Run Up Rate warm	MW/min	0.0333	0.0333
Run Up Rate cold	MW/min	0.0133	0.0133
Rating	MW	17	17
Min Up Time	h	12	12
Must-Run Units	-	Yes	Yes
Max Ramp Up	MW/min	5	5
Max Ramp Down	MW/min	5	5
Firm Capacity	MW	18.62	18.62
Earliest Retirement	-	01/01/2021	01/01/2021
Latest Retirement	-	31/12/2026	31/12/2023
Governing		Yes	Yes

Source: BLPC Barbados Plexos Model

C.2 Reciprocating internal combustion engines

C.2.1 General

Applications and output range

Reciprocating internal combustion engines (RICEs) have existed since the nineteenth century and commonly provide power for transport but can also be used for stationary power generation by connecting them to a generator to produce electricity.

A RICE works by introducing air and fuel into a cylinder in which a piston sits. Combustion of the fuel causes the piston to travel the length of the cylinder. This causes a crankshaft, connected to the piston, to rotate. Multiple cylinders power a single crankshaft. The rotation of the crankshaft is used to drive a generator and produce electricity.

There are two main engine designs used for power generation. In a Diesel-cycle engine, air in the cylinder is compressed to a high pressure, raising its temperature so that fuel injected into the cylinder auto-ignites (compression ignition). In an Otto-cycle engine, a spark plug is used to ignite pre-mixed air and fuel (spark ignition).

Engines for power generation are categorised by the type of ignition (compression or spark ignition) and crankshaft speed (high, medium, or low speed).

RICEs have outputs in the kW range (high speed engines) up to around 50 MW (low speed engines). Most engines sold for utility scale power generation are medium speed engines with outputs between 5 MW and 18 MW.

Due to their modular nature, engines can be deployed in multiple units for power generation applications. This ranges from installing single units or multiple units next to each other allowing plants with outputs of well over 100 MW.

RICEs are commonly used for power generation in the following applications:

- Small/island networks: Due to their relatively small outputs, RICEs are well suited to small networks such as islands where they generate reliable baseload power. Mott MacDonald has a long history of working on projects in Mauritius, Barbados, the Seychelles, Gibraltar, the West Indies, and other small and/or island networks.
- Where there is a lack of gas: RICEs can fire a wider range of fuels than comparatively sized gas turbines (including heavy fuel oil) and are therefore often deployed in small networks where there is no natural gas or liquified natural gas (LNG) available.
- Standby/peaking: RICEs have quick start up times and are therefore often used for standby or peaking applications; only generating electricity when demand, and therefore power prices, are high.
- Emergency power: Companies such as Aggreko specialise in delivering engines for emergency power, e.g., to remote communities where the normal power supply has been interrupted by a catastrophic failure or a natural disaster.
- Black start: RICEs are also used to provide black start services to a network since they can be started independently without the need of utilities (fuel and power) from external grids. This allows network operators to repower a grid that has ‘blacked out’ following a major fault or interruption.

RICEs are typically used in open cycle, i.e., without a waste heat steam generation. Their low exhaust temperatures tend to make combined cycle operation less economical at small scales, as the additional cost of waste heat recovery equipment and a steam turbine outweigh the additional power that can be generated in combined cycle. Nevertheless, OEMs do offer combined cycle packages; these tend to be installed on large scale projects (over 100 MW) or where fuel is particularly expensive.

While there are numerous OEMs providing small high speed RICEs, there are fewer suppliers of engines for medium speed power generation at the utility scale (notably Wärtsilä, MAN, MTU (Rolls Royce) and MWM (Caterpillar).

Fuel

Compression ignition RICEs operate on diesel or heavy fuel oil or can run in dual-fuel mode that fires natural gas with a small amount of liquid pilot.

Spark ignition RICEs operate on natural gas but can also fire other gaseous fuels such as propane or landfill gas.

Performance

RICEs achieve thermal efficiencies of between 40% and 45% in open cycle. Diesel engines tend to be slightly more efficient than gas engines, and low speed engines tend to be slightly more efficient than medium speed engines (although medium speed technology has improved, and the difference has reduced in recent decades).

Unlike gas turbines, the efficiency of a RICEs does not drop significantly when operating at part load (less than 100% load). RICE efficiencies only tend to drop significantly below 50% load. In addition, due to their modular nature, where multiple units are installed in the same plant, the operator can shut down individual units and continue operating the remaining units at full load to maintain high efficiency when demand reduces.

RICEs can maintain output and efficiency over a wider range of ambient temperatures than gas turbines.

RICEs can continuously operate at loads as low as 20% of full load (minimum stable generation).

Medium speed RICEs used for power generation tend to take around five to ten minutes to start up in 'hot start' mode (where the unit has only recently been shut down and still retains its heat). 'Cold starts may take from 15 to 30 minutes depending on the OEM.

Engines have high ramp rates and, once operating stably, can vary their load by 100% load per minute.

RICEs produce higher nitrogen oxides (NOx) emissions than gas turbines. Spark ignition models can achieve less than 200 mg/Nm^3 while compression ignition engines typically achieve less than 400 mg/Nm^3. Where national regulations require lower NOx emissions, selective catalytic reduction (SCR) can be deployed. In SCR, ammonia or urea is injected into the exhaust stream of the engine and, with the aid of a catalyst, converts NOx into N_2, and H_2O.

Construction

Power plant costs for medium speed plants are in the region of USD 1,000 to USD 1,500 per kW for a typical project. Costs may vary depending on the scope of works, location, appetite of the OEMs and ground conditions.

Construction times (from notice to proceed to commercial operation) for permanent medium speed power plants using 18 MW units are typically around 18 months. RICEs can be delivered and installed much quicker for temporary or emergency applications.

Operation and maintenance

RICEs have a reputation for reliability. Equivalent forced outage rates (EFOR) are around 0.5% in open cycle. There is a low risk of teething issues associated with new models, as upgrades today tend to be incremental.

RICEs are relatively simple to operate, and remote/unmanned operation is possible, i.e., without a permanent presence of operators on site.

Maintenance is typically more frequent and more expensive per MWh than equivalent gas turbines.

O&M costs are in the region of USD 15 to USD 30 per MWh.

Due to the much larger number of RICEs in service than gas turbines there is a larger pool of expertise available for maintenance and service charge rates are lower.

Medium speed power plants can be expected to operate for at least 25 years, assuming overhauls in line with manufacturer's recommendations take place.

C.2.2 Unit D10, D11, D12, D13, D14 and D15

Low Speed Diesel (LSD) Units D10 to D13 are rated at 11 MW and achieve varying efficiencies. gross efficiencies. LSD Units D14 and D15 are rated at 27 MW.

These units provide the exhaust heat to the Waste Heat Recovery Units (WH1 and 2) which can produce 1.5 MW and 2.2 MW, respectively. Waste Heat Unit 1 is fed by Units D10, D11, D12, D13 and Waste Heat Unit 2 is fed by Units D14 and D15.

Table C.2 below presents key information on the units as presented in the Barbados Plexos model obtained from BLPC.

These units are not must-run units, i.e., they offer more flexibility in operation. Minimum loading for units D10-13 is 7 MW and D14-15 is 15 MW. For units D10-13 this would require 9.23 minutes to reach from warm or cold start, while units D14-15 can reach their minimum stable level even faster from cold and warm start within 7.14 minutes. Units D10-13 and D14-15 ramp rates are 1 MW/min and 3 MW/min respectively, which allows them to be reasonably flexible during operation and good units to keep in operation as the penetration of variable renewable energy increases in the grid.

Units D10 to D13 are between 30 and 38 years old, with unit D13 being upgraded in 1993. Units D14 and D15 are 15 years old. The units' latest retirement dates are given as 2028 for units D10-13 and 2035 for units D14-15.

Their outage rates (maintenance and forced outage) are higher than expected for units of this type, for which an annual outage rate of about 8% should be achievable.

These units operate with on heavy fuel oil at an efficiency which is in line with our expectations.

Table C.2: Key Information on D10 – D15

Property	Units	D10	D11	D12	D13	D14	D15
Units	-	1	1	1	1	1	1
Max Capacity	MW	12.5	12.5	12.5	12.5	29.7	29.7
Min Stable Level	MW	7	7	7	7	15	15
Run Up Rate Warm	MW/min	0.75867	0.75867	0.75867	0.75867	2.1	2.1
Run Up Rate Cold	MW/min	0.3793	0.3793	0.3793	0.3793	1.05	1.05
Rating	MW	11	11	11	11.5	27	27
Min Up Time	h	2	2	2	2	2	2
Must-Run Units	-	No	No	No	No	No	No
Max Ramp Up	MW/min	1	1	1	1	3	3
Max Ramp Down	MW/min	1	1	1	1	3	3
Firm Capacity	MW	10.55	10.55	10.55	11.03	25.97	25.97
Earliest Retirement	-	01/01/2021	01/01/2021	01/01/2021	01/01/2021	01/01/2021	01/01/2021
Latest Retirement	-	31/12/2028	31/12/2028	31/12/2028	31/12/2028	31/12/2035	31/12/2035
Governing		Yes	Yes	Yes	Yes	No	No

With effective maintenance all of these low-speed diesel units can be expected to give reliable service for another 10 to 20 years. There is no strict limit on how long they can be kept in use, and some similar units fifty years old and more are still in operation. Availability of spare parts is not considered an issue. Best reliability is obtained by running these units at baseload and minimising start stop operation.

Low-speed engines can use a variety of liquid fuels, and conversion of these engines to operate on biodiesel or other renewable liquid fuel will not be difficult to accomplish. Using biodiesel imposes some restrictions:

- Power and efficiency reduction. This depends on the biodiesel blend. Typically, < 20% biofuel, power reduction is 2%, efficiency reduction 3%, >20% biofuel, power reduction is up to 12%, efficiency reduction up to 18%. (Figures dependent on biofuel type).
- Fuel conditioner (for >20% biofuel) required to prevent deposition within engine.

- Lubricating oil lifetime is reduced, typically leading to service intervals halving.
- Biodiesel lifetime is limited, making it unsuitable for use as a fuel for back-up power.

C.2.3 Resiliency Bridge (RB)

The RB Medium Speed Diesel Engine project is under construction, therefore the data presented in Table C.3 below is not yet validated though operational performance but based on pre-construction information available through the EPC contractor.

The RB project's intention is to contribute to maintaining stable conditions within the energy system as Barbados shifts to higher levels of variable renewable energy and expected to remain in service over the next 30 years. It is a modern engine with a high fuel efficiency as would be expected from this technology. The RB project will be able to provide ancillary services to the system as the medium speed diesel engine provides reasonable flexibility to accommodate changes in variable renewable energy generation, thus maintaining system inertia, frequency, and reliability. The engine is able to reach minimum stable level in just over five minutes from cold or warm start and ramp up to its rated capacity within a minute. Although the engine cannot provide instantaneous response from sudden loss in solar or wind power, it is a suitable secondary response after BESS.

Table C.3: Key Information on Resiliency Bridge

Property	Units	Resiliency Bridge
Units	-	4 under construction
Total Capacity	MW	33
Max Capacity per unit	MW	8.51
Min Stable Level	MW	2.55
Run Up Rate	MW/min	0.49
Run Up Rate	MW/min	0.49
Rating	MW	8.51
Must-Run Units	-	No
Max Ramp Up	MW/min	8.51
Max Ramp Down	MW/min	8.51
Firm Capacity	MW	8.51
Governing		Yes

These are well-proven engines of a type in wide use in many different countries. They are capable of rapid and frequent starting and stopping and are well suited to providing ancillary services to the distribution system and to support the variable nature of renewable power sources. They can be expected to give reliable service for at least thirty years.

These engines are normally operated on light or heavy fuel oil, but they can also operate successfully on biofuels such as oils from various oilseeds such as palm oil, palm stearin, rape seed oil, sunflower oil, and jatropha oil. Liquid biofuels can also be from non-vegetable sources – e.g., oils or fats from fish, poultry and animals, and refined biofuels such as transesterified biodiesel or hydrogenated renewable diesel can also be used. Note however that some of these fuels will have lower calorific value than mineral oils and the output of the engines may be reduced as a consequence.

C.2.4 Small 2020 Diesel Units (APR)

These are containerised diesel units supplied by APR Energy. The engines are high speed, reconditioned and are used for peaking and back-up. The availability of the units is reduced compared to medium or low speed engines however the large number of units means the impact of losing one unit is small. Two spare units are kept which can be connected to the system in the event of a failed unit not being repairable.

Efficiency is poor in relation to medium or low speed engines, however in the context of peaking and back-up operation this is acceptable.

Planned retirement date is 2030. Lifetime of high-speed diesels is a function of number of starts and number of running hours. Typically, the engines require major refurbishment after 25,000 to 50,000 running hours although this is strongly affected by the operation regime and to a lesser effect fuel quality. Expected run hours to 2030 will be considerably less than 25,000 although number of starts may be high. However, provided units are maintained in line with manufacturer's guidelines, it can be expected these will run at the expected availability.

Containerised diesel units rated at 1.5 MW are common plant items and are frequently used as a source of back-up or emergency power for small grids or large consumers. They are readily available.

Table C.4: Key Information on Small 2020 Diesel Units

Property	Units	APR small diesels	Notes
Units	-	10	2 units held store
Total Capacity	MW	15	
Max Capacity per unit	MW	1.5	
Min Stable Level	MW	0.5	Units run at full load
Rating	MW	1.5	
Firm Capacity	MW	1.5	

C.3 Cogeneration

There are two waste heat steam turbines at Spring Garden Power Station: WH01 and WH02. Waste heat turbines use the heat from the LSD power plants to create steam and additional generation.

C.3.1 Waste Heat Unit 1 and 2

Waste Heat Unit 1 is fed by Units D10, D11, D12 and D13, while Waste Heat Unit 2 is fed by Units D14 and D15.

Table C.5 provides key information on Waste Heat units one and two.

The waste heat units are a form of heat integration in the system to offer higher overall efficiency in the power generation process of the plant. The earliest and latest retirement dates for these units align with units D10-13, to enable cogeneration.

Their outage rates (maintenance and forced outage) are higher than expected.

Table C.5: Key Information on WH01 and WH02

Property	Units	WH01	WH02
Units	-	1	1
Max Capacity	MW	1.5	2.2
Min Stable Level	MW	0.6	0.8
Rating	MW	1.5	2.2

Property	Units	WH01	WH02
Firm Capacity	MW	1.5	1.8
Earliest Retirement	-	01/01/2021	01/01/2021
Latest Retirement	-	31/12/2028	31/12/2035
Governing		No	No

These units are powered by the heat in the exhaust gases from the engines and do not consume fuel. They cannot therefore be operated independently of the diesel engines.

The heat in the engine exhaust gases is used to produce steam in waste heat boilers associated with each engine, and this steam drives the steam turbines to produce electricity. The waste heat boilers can be prone to difficulties arising from corrosion and from the deposits of soot produced by the exhaust gases. This may be the reason for the high maintenance and forced outage rates shown in the table above.

It is to be noted that if biofuels are introduced, the nature of the engine exhaust gases will change and there is a risk of deposits forming in the waste heat boilers which may be difficult to deal with. Since the composition of biofuels can vary widely, this effect is difficult to predict. In the case of such difficulties the waste heat boilers can of course be taken out of service, but this will mean giving up the additional electricity generation which they provide.

Since the additional electricity produced by these steam turbines is relatively small, it can sometimes happen that they are not given priority by the power station maintenance teams and this can lead to poor performance in terms of maintenance and forced outages.

C.4 Aeroderivative gas turbines

Applications and output range

Aeroderivative gas turbines (GTs) for power generation emerged in the 1960s and were originally directly adapted from existing aircraft engines.

Like all GTs, aeroderivative GTs work by drawing air through a compressor. In the compressor, the air is pressurised as it passes through a series of rotating and stationary blades. The pressurised air then enters a combustion chamber where fuel is injected. The fuel combusts and the resulting hot, pressurised gas expands through a turbine section, made up of a further series of rotating and stationary blades, and this causes the shaft to rotate. The shaft drives the compressor at the front of the engine and the remaining energy drives a separate power turbine generator producing electricity.

Aeroderivative GTs have outputs from around 5 MW to 110 MW. Aeroderivative GTs are commonly used in the following applications:

- Baseload power on small networks.
- Peaking/standby power due to their quick start up times.
- Short term flexible response services to networks to help balance generation with load, for the same reasons as above.
- Combined heat and power (CHP), also known as cogeneration: The exhaust heat from the gas turbine is used to produce hot water or steam which can be used by the process. The size of aeroderivative gas turbines makes them suitable to process plants, factories, and other large facilities (e.g., hospitals).
- Offshore (e.g., oil platforms) due to their low weight and small footprint.
- Black start.

- Remote locations: Aeroderivative GTs can be operated remotely without the need for manned sites, so are often deployed where power is required in remote locations.

Aeroderivative GTs are typically installed in open cycle. Combined cycle operation may be less economical at small scale but may be installed as part of a Combined Heat and Power (CHP) scheme where steam can be extracted from the steam turbine to provide heat.

Fuel

Aeroderivative GTs typically fire natural gas or diesel but can fire other gaseous fuels such as propane and jet fuel.

The use of biofuels and biofuel blends has been the subject of studies due to high demand for such application and successful tests have been carried out, but this cannot yet be regarded as a mature technology.

Dual fuel operation, where the engine can switch over from gas to diesel operation and vice versa, is possible if the combustion system has been designed for it.

Gas turbines need higher gas supply pressures than RICEs. This is because the fuel needs to be injected into the combustion chamber at a higher pressure than the pressurised air leaving the compressor stage. Fuel gas compressors can be installed on power plant sites where the local gas network pressure is low or unreliable. Most aeroderivative GTs require gas pressures of over 20 bar, although it is noted that the Trent models, for example, require over 50 bar at the point of connection.

OEMs

GE and Siemens are the main original equipment manufacturers (OEMs) of aeroderivative GTs at utility scale. Rolls Royce sold its aeroderivative GT business to Siemens in 2014; prior to this it was also considered a major supplier.

Key models from GE include the LM2500 (34 MW), LM6000 (58 MW) and LMS100 (117 MW).

Key models form Siemens include the SGT-A35 (previously Rolls Royce's Industrial RB211) (37 MW) and the SGT-A65 (previously Rolls Royce's Industrial Trent 60) (62 MW).

Performance

Aeroderivative GTs achieve thermal efficiencies between 37% and 44% in open cycle and between 50% and 55% in combined cycle.

Part load efficiency is relatively good compared to heavy duty GTs, since aeroderivative GT technology is derived from aircraft engines which are inherently required to make frequent load changes during flights.

All GT performance is highly susceptible to ambient temperature. GT power output is directly related to the mass flow of air through the engine. As air temperatures increase, the density of air decreases and the mass of air flowing through the GT and, in turn, power output drops. In cold climates, the effect is the opposite. OEMs tend to quote GT outputs at ISO conditions (15 °C). Power output may be up to 25% lower at 40 °C.

Aeroderivative GTs can continuously operate at 20% to 40% of full load, depending on the model. Aeroderivative GTs tend to take around ten minutes to start up in 'hot start' mode in open cycle. Start times are longer in combined cycle mode due to the steam cycle limitations.

Aeroderivative gas turbines have high ramp rates and, once operating stably, can vary their load by up to 50% load per minute whilst maintaining emissions within requirements.

Aeroderivative GTs can achieve NOx emissions less than 30 mg/Nm^3 (15 ppm) when firing gas and 50 mg/Nm^3 (25 ppm) when firing diesel.

NOx reduction is achieved through reducing the temperature of the flame. This was first done through water or steam injection into the combustion chamber. There are several disadvantages with this method; primarily that large quantities of water are required. OEMs have also developed dry low NOx burners for fuel gas whereby most of the fuel is burnt at cool and fuel-lean conditions to avoid excessive NOx production. NOx reduction for liquid fuels is however predominantly still achieved by water injection.

Construction

Construction costs are in the region of USD 350 to USD 550 per kW in open cycle and USD 1,000 to USD 1,350 per kW in combined cycle for a typical project. Costs may vary depending on the scope of works, location, appetite of the OEMs and ground conditions.

Construction times are typically around 12 months in open cycle and 24 months in combined cycle. Both GE and Siemens offer prefabricated trailer mounted models which are designed to be deployed rapidly around the world like emergency RICE units.

Operation and maintenance

Aeroderivative GTs, by design, are considered highly reliable. Equivalent Forced Outage Rates (EFORs) are around 0.5% in open cycle operation. There is a low risk of teething issues in new aeroderivative GT models, as upgrades today tend to be incremental.

Aeroderivative GTs in open cycle are relatively simple to operate and remote/unmanned operation is possible, i.e., without a permanent presence of operators on site.

Major maintenance of aeroderivative GTs often follow an ‘engine exchange’ concept whereby either the whole engine or key components are swapped out with an exchange unit and removed for service off site. This minimises downtime.

O&M costs are in the region of USD 10 to USD 20 per MWh.

Aeroderivative engines can be expected to operate for at least 25 years, assuming overhauls in line with manufacturer’s recommendations take place.

C.4.1 Unit GT02, GT03, GT04, GT05, GT06

Table C.6 provides key information for the BLPC gas turbines. GT02 is designed for operation on diesel oil, while the other turbines are normally operated on aviation fuel Jet A-1.

These units have a minimum loading of 6 MW which would require five minutes to reach. Their ramp rate is 3 MW/min, which allows them to be very flexible during operation.

These units range from 18 to 30 years in age and are due to retire earliest in 2021 or latest between end of year 2023 and 2030. They have a forced outage rate that are somewhat higher than what we would expect.

In terms of efficiency, the units currently operate using jet fuel, with a fuel efficiency lower than what we would expect for newer plant but note that age is a factor here with the higher range of consumption from the oldest unit.

Table C.6: Key Information on GT02 – GT06

Property	Units	GT02	GT03	GT04	GT05	GT06
Units	-	1	1	1	1	1
Max Capacity	MW	13	13	20	20	20

Property	Units	GT02	GT03	GT04	GT05	GT06
Min Stable Level	MW	6	6	6	6	6
Run Up Rate	MW/min	1.2	1.2	1.2	1.2	1.2
Rating	MW	11	11	18	18	18
Min Up Time	h	3	3	3	3	3
Must-Run Units	-	No	No	No	No	No
Max Ramp Up	MW/min	3	3	3	3	3
Max Ramp Down	MW/min	3	3	3	3	3
Firm Capacity	MW	10.89	10.91	19.8	19.8	19.8
Earliest Retirement	-	01/01/2021	01/01/2021	01/01/2021	01/01/2021	01/01/2021
Latest Retirement	-	31/12/2023	31/12/2026	31/12/2028	31/12/2030	31/12/2030
Governing		Yes	Yes	Yes	Yes	Yes

Due to their relatively low efficiency and the use of high value fuels, these units are not suitable for continuous baseload operation but are best kept for peaking or emergency duty.

Their very rapid starting and loading ability makes them ideal for supporting renewable generation. Despite the ages of some of the units, they are still within good operating condition and can be useful in support of firm generation from variable renewable energy. Because these units are designed for low-capacity factor operation and back-up these are most suitable to continue to perform this function

In contrast to the LSD units, there is however little opportunity for conversion of these units to use renewable fuels.

C.5 Battery Energy Storage Systems (BESSs)

Battery Storage as a technology is also discussed further below in the Storage Technology Study (section 6).

BLPC operate a 5 MW (21 MWh) TESLA Battery Storage Plant at Trents which was completed in 2018. Its expected useful life is 10 years which is in line with normal warranty and performance expectations based on one cycle per day. There is a degradation of the energy storage capacity which is in line with our expectation and manufacturer warranties.

It would normally be expected that assets are replaced or upgraded at this point; however, it could be possible to extend the asset life or re-purpose if the remaining performance of the asset is acceptable for the intended use case.

The charge and discharge efficiencies are in line with typical values for such assets.

The unit can be and is used for frequency response as well as to perform peak shaving such that thermal units on the system can operate more efficiently.

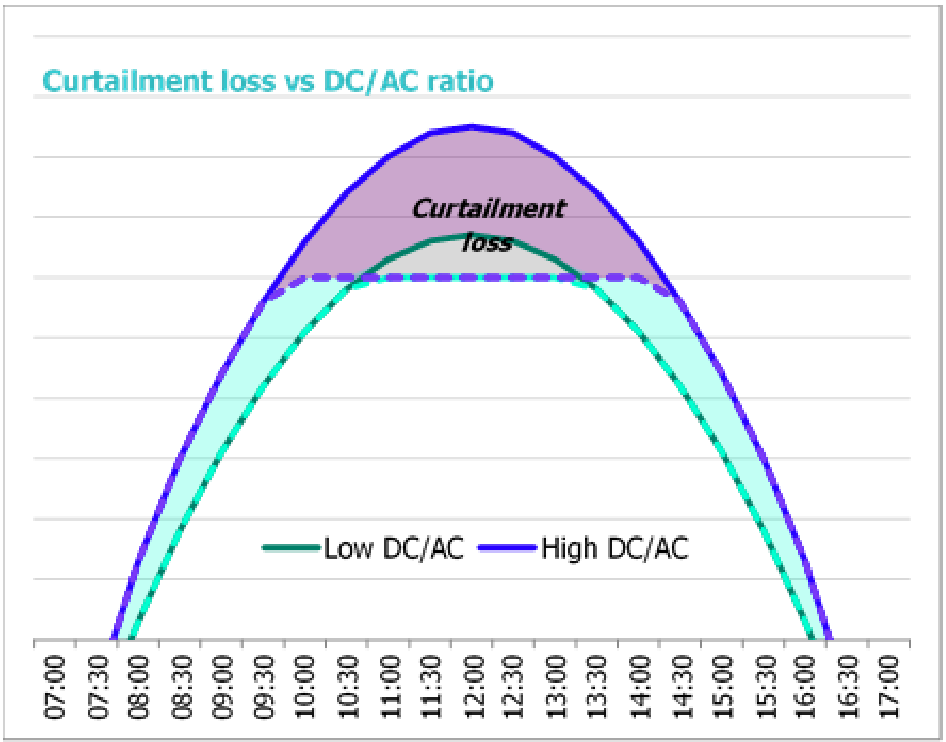
Due to the modularity of the battery storage systems, the reliability is nominally 100%.

C.6 Solar PV

BLPC operates a 10 MW (DC) PV plant at Trents. In line with typical asset performance, degradation of 0.6% of peak capacity is expected each year over a 25-year life. The plant requires little maintenance which would also be expected to be potentially carried out during down-time with 1% per year.

It has a typical DC/AC ratio of 1.3 which means that the peak capacity (in DC-power) that can be achieved by the modules is 30% higher than the AC-power output exported to the grid through the inverters. It is a typical design for utility-scale projects, although higher DC/AC ratios can also be beneficial (albeit usually more expensive due to higher curtailment losses) to achieve a better generation profile (see Figure C.10below).

Figure C.10: Solar Generation Profiles for different DC/AC ratios



Source: Mott MacDonald

It is a ground-mounted plant on fixed structures which are robust and reliable with high resiliency to weather impacts. Tracking systems (as opposed to fixed structures) would typically be used where direct solar irradiation is high (as compared to diffused) which is not the case in tropical climates.

D. Demand Forecast Data

Table D.1: Historical and projected sector real GDP growth

Sector	2010-2015	2016-2020	2021-2025	2026-2030	2031-2035	2036-2040
Industry	-2.1 %	-1.5 %	0.5 %	0.3 %	0.3 %	0.3 %
Commercial	0.0 %	0.0 %	1.0 %	0.9 %	0.9 %	0.9 %
Hotel and Restaurants	0.7 %	5.5 %	0.5 %	0.5 %	0.5 %	0.5 %
Transport	1.2 %	0.8 %	1.5 %	1.4 %	1.3 %	1.3 %
Total	0.7 %	0.4 %	0.8 %	0.7 %	0.7 %	0.7 %

Source: MESBE – LINDA energy demand model

Table D.2: Annual percentage change in electricity intensity by sector

Sector	2001-2010	2010-2015	2016-2020	2021-2025	2026-2030	2031-2035	2036-2040
Industry	1.6%	1.6%	2.6%	2.2%	0.4%	0.0%	-0.2%
Commercial	1.7%	-2.0%	-0.1%	-0.3%	-0.2%	-0.2%	-0.2%
Hotels and Restaurants	9.2%	1.1%	-3.7%	1.8%	1.6%	1.4%	1.3%
Residential electricity use (not intensity)	-0.5%	2.1%	0.3%	2.7%	0.8%	0.2%	0.1%

Source: MESBE – LINDA energy demand model

Table D.3: MESBE's forecasted electricity demand (GWh) by sector in the Reference, High, and Low scenarios

Year	Reference Scenario					High Scenario					Low scenario				
	Industry	Commercial	Hotels and Restaurants	Residential	**Total demand**	Industry	Commercial	Hotels and Restaurants	Residential	**Total demand**	Industry	Commercial	Hotels and Restaurants	Residential	**Total demand**
2020	121	346	123	351	**941**	121	346	123	351	**941**	121	346	123	351	**941**
2021	124	348	126	361	**959**	128	357	130	373	**988**	120	337	119	345	**921**
2022	128	350	129	370	**977**	135	368	138	396	**1037**	119	328	116	338	**901**
2023	131	353	132	380	**996**	142	380	147	421	**1090**	117	320	112	331	**880**
2024	135	355	135	391	**1016**	150	393	156	447	**1146**	116	312	109	325	**862**
2025	138	357	138	401	**1034**	158	405	165	475	**1203**	115	304	106	319	**844**
2026	139	360	141	404	**1044**	160	413	171	479	**1223**	116	300	105	321	**842**
2027	140	362	144	407	**1053**	161	421	177	483	**1242**	116	297	105	323	**841**
2028	141	365	147	410	**1063**	163	429	183	487	**1262**	117	293	105	325	**840**
2029	143	367	150	413	**1073**	164	437	189	491	**1281**	118	290	104	327	**839**
2030	144	370	153	417	**1084**	165	445	195	495	**1300**	118	286	104	329	**837**
2031	144	372	156	418	**1090**	166	451	201	496	**1314**	119	284	104	330	**837**
2032	144	375	159	418	**1096**	166	458	206	497	**1327**	119	282	105	331	**837**
2033	145	377	162	419	**1103**	166	465	211	498	**1340**	119	279	105	332	**835**
2034	145	380	165	420	**1110**	167	471	217	499	**1354**	120	277	106	333	**836**
2035	145	382	169	421	**1117**	167	478	222	500	**1367**	120	275	106	334	**835**
2036	145	384	172	422	**1123**	167	484	227	500	**1378**	120	273	107	334	**834**
2037	145	387	175	422	**1129**	167	490	232	500	**1389**	120	272	108	334	**834**
2038	146	389	178	422	**1135**	167	496	237	501	**1401**	120	270	109	335	**834**
2039	146	392	181	423	**1142**	168	502	242	501	**1413**	120	268	110	335	**833**
2040	146	394	184	423	**1147**	168	508	247	501	**1424**	120	266	111	335	**832**

Source: MESBE – LINDA energy demand mode

Table D.4: EV share of total Vehicle fleet by year

Scenario	2025	2030	2035	2040
Base	15%	60%	87%	100%
Low	9%	30%	45%	60%
Aggressive	30%	100%	100%	100%

Source: Mott MacDonald estimates

Figure D.1: MegaPower charge points – Barbados

Source: [52]

Table D.5: Forecasted EV electricity demand (GWh) by vehicle type, in the Base, Aggressive, and Low scenarios.

Year	Base Scenario				Aggressive Scenario				Low Scenario			
	Light-Duty Vehicles	Medium-Duty Vehicles	Heavy-Duty Vehicles	**Total EV Demand**	Light-Duty Vehicles	Medium-Duty Vehicles	Heavy-Duty Vehicles	**Total EV Demand**	Light-Duty Vehicles	Medium-Duty Vehicles	Heavy-Duty Vehicles	**Total EV Demand**
2020	1	0	1	**2**	1	0	1	**2**	1	0	1	**2**
2021	3	1	1	**5**	6	2	1	**9**	2	1	1	**4**
2022	10	4	1	**15**	21	7	1	**29**	6	2	1	**10**
2023	21	7	2	**30**	42	14	4	**60**	13	4	1	**18**
2024	30	10	3	**43**	60	20	6	**87**	18	6	2	**26**
2025	45	15	5	**65**	91	30	10	**130**	27	9	3	**39**
2026	61	20	6	**87**	122	40	13	**174**	36	12	4	**52**
2027	82	27	9	**118**	165	54	17	**236**	49	16	5	**71**
2028	138	45	14	**197**	214	70	22	**307**	64	21	7	**92**
2029	154	50	16	**220**	258	84	27	**369**	77	25	8	**111**
2030	185	60	19	**264**	309	100	32	**441**	93	30	10	**132**
2031	205	66	21	**292**	310	100	32	**442**	102	33	11	**146**
2032	227	73	24	**324**	311	100	32	**444**	112	36	12	**160**
2033	247	79	26	**352**	313	100	33	**445**	122	39	13	**174**
2034	260	83	27	**371**	314	100	33	**447**	132	42	14	**188**
2035	274	87	29	**390**	315	101	33	**448**	142	45	15	**202**
2036	285	91	30	**405**	316	101	33	**450**	152	48	16	**216**
2037	295	94	31	**420**	318	101	33	**451**	162	51	17	**230**
2038	304	96	31	**432**	319	101	33	**453**	172	54	18	**244**
2039	314	99	32	**445**	320	101	33	**454**	182	58	19	**259**
2040	321	101	33	**455**	321	101	33	**455**	193	61	20	**273**

Source: MESBE – LINDA energy demand model

Table D.6: Build-up of Cruise Liner's electricity demand in the Base case

Year	Ship days/ Year	Ships /d ay (6mth season)	% share electrified	Ship Days/ Year (electric)	MW/Ship	Hours in port	MWh/Year	Electric ships/ Days	MW/Hour (20:00-07:00)	MW/Hour (07:00-08:00)	MW/Hour (08:00-19:00)	MW/Hour (19:00-20:00)
2020	130	0.7	0%	0	4.5	12	-	-	-	-	-	-
2021	200	1.1	0%	0	4.5	12	-	-	-	-	-	-
2022	450	2.5	0%	0	4.5	12	-	-	-	-	-	-
2023	600	3.3	2%	12	4.5	12	648	1	0	4.5	4.5	4.5
2024	700	3.8	4%	28	4.5	12	1,512	1	0	4.5	4.5	4.5
2025	900	4.9	6%	54	4.5	12	2,916	1	0	4.5	4.5	4.5
2026	950	5.2	10%	95	4.5	12	5,130	1	0	4.5	4.5	4.5
2027	1000	5.5	20%	200	4.5	12	10,800	2	0	4.5	9.0	4.5
2028	1000	5.5	30%	300	4.5	12	16,200	2	0	4.5	9.0	4.5
2029	1050	5.8	40%	420	4.5	12	22,680	3	0	4.5	13.5	4.5
2030	1100	6.0	50%	550	4.5	12	29,700	4	0	9.0	18.0	9.0
2031	1100	6.0	60%	660	4.5	12	35,640	4	0	9.0	18.0	9.0
2032	1100	6.0	70%	770	4.5	12	41,580	5	0	9.0	22.5	9.0
2033	1100	6.0	80%	880	4.5	12	47,520	5	0	9.0	22.5	9.0
2034	1100	6.0	90%	990	4.5	12	53,460	6	0	13.5	27.0	13.5
2035	1100	6.0	100%	1100	4.5	12	59,400	6	0	13.5	27.0	13.5
2036	1100	6.0	100%	1100	4.5	12	59,400	6	0	13.5	27.0	13.5
2037	1100	6.0	100%	1100	4.5	12	59,400	6	0	13.5	27.0	13.5
2038	1100	6.0	100%	1100	4.5	12	59,400	6	0	13.5	27.0	13.5
2039	1100	6.0	100%	1100	4.5	12	59,400	6	0	13.5	27.0	13.5
2040	1100	6.0	100%	1100	4.5	12	59,400	6	0	13.5	27.0	13.5

Source: Mott MacDonald estimates

Table D.7: Cruise Liners forecasted annual electricity demand and hourly profiles in the Base, High, and Low cases

Year	Base Case					High Case					Low Case				
	MWh/Year	MW/Hour (20:00-07:00)	MW/Hour (07:00-08:00)	MW/Hour (08:00-19:00)	MW/Hour (19:00-20:00)	**MWh/Year**	MW/Hour (20:00-07:00)	MW/Hour (07:00-08:00)	MW/Hour (08:00-19:00)	MW/Hour (19:00-20:00)	**MWh/Year**	MW/Hour (20:00-07:00)	MW/Hour (07:00-08:00)	MW/Hour (08:00-19:00)	MW/Hour (19:00-20:00)
2020	**-**	-	-	-	-	**-**	-	-	-	-	**-**	-	-	-	-
2021	**-**	-	-	-	-	**-**	-	-	-	-	**-**	-	-	-	-
2022	**-**	-	-	-	-	**-**	-	-	-	-	**-**	-	-	-	-
2023	**648**	0	4.5	4.5	4.5	**648**	0	4.5	4.5	4.5	**-**	0	0.0	0.0	0.0
2024	**1,512**	0	4.5	4.5	4.5	**7,560**	0	4.5	4.5	4.5	**-**	0	0.0	0.0	0.0
2025	**2,916**	0	4.5	4.5	4.5	**24,300**	0	4.5	13.5	4.5	**2,430**	0	4.5	4.5	4.5
2026	**5,130**	0	4.5	4.5	4.5	**30,780**	0	9.0	18.0	9.0	**5,130**	0	4.5	4.5	4.5
2027	**10,800**	0	4.5	9.0	4.5	**37,800**	0	9.0	18.0	9.0	**8,100**	0	4.5	4.5	4.5
2028	**16,200**	0	4.5	9.0	4.5	**43,200**	0	9.0	22.5	9.0	**10,800**	0	4.5	9.0	4.5
2029	**22,680**	0	4.5	13.5	4.5	**51,030**	0	13.5	27.0	13.5	**14,175**	0	4.5	9.0	4.5
2030	**29,700**	0	9.0	18.0	9.0	**59,400**	0	13.5	27.0	13.5	**17,820**	0	4.5	9.0	4.5
2031	**35,640**	0	9.0	18.0	9.0	**59,400**	0	13.5	27.0	13.5	**26,730**	0	4.5	13.5	4.5
2032	**41,580**	0	9.0	22.5	9.0	**59,400**	0	13.5	27.0	13.5	**35,640**	0	9.0	18.0	9.0
2033	**47,520**	0	9.0	22.5	9.0	**59,400**	0	13.5	27.0	13.5	**47,520**	0	9.0	22.5	9.0
2034	**53,460**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5
2035	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5
2036	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5
2037	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5
2038	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5
2039	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5
2040	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5	**59,400**	0	13.5	27.0	13.5

Source: Mott MacDonald estimate

Table D.8: Potential build-up of electricity use for cooking in the Residential and Commercial sectors (Base, High, and Low cases)

							Base Case					High Case					Low Case				
Year	Gas Use (GWh)		Relative efficiency (electricity/gas)		% substitutable by electricity		% share substituted		Electricity consumption (GWh)			% share substituted		Electricity consumption (GWh/year)			% share substituted		Electricity consumption (GWh/year)		
	Resid.	Comm.	Resid.	Comm.	Resid.	Comm.	Resid.	Comm.	Resid.	Comm.	**Total**	Resid.	Comm.	Resid.	Comm.	**Total**	Resid.	Comm.	Resid.	Comm.	**Total**
2020	124	116	2	1.5	75%	50%	0%	0%	0.0	0.0	**0.0**	0%	0%	0.0	0.0	**0.0**	0%	0%	0.0	0.0	**0.0**
2021	124	116	2	1.5	75%	50%	2%	2%	0.9	0.6	**1.5**	2%	2%	0.9	0.6	**1.5**	0%	0%	0.0	0.0	**0.0**
2022	124	116	2	1.5	75%	50%	5%	4%	2.3	1.5	**3.8**	5%	4%	2.3	1.5	**3.8**	0%	0%	0.0	0.0	**0.0**
2023	124	116	2	1.5	75%	50%	10%	8%	4.7	2.9	**7.6**	10%	8%	4.7	2.9	**7.6**	0%	0%	0.0	0.0	**0.0**
2024	124	116	2	1.5	75%	50%	15%	11%	7.0	4.4	**11.3**	20%	15%	9.3	5.8	**15.1**	0%	0%	0.0	0.0	**0.0**
2025	124	116	2	1.5	75%	50%	20%	15%	9.3	5.8	**15.1**	50%	38%	23.3	14.5	**37.8**	5%	4%	2.3	1.5	**3.8**
2026	124	116	2	1.5	75%	50%	25%	19%	11.6	7.3	**18.9**	60%	45%	27.9	17.4	**45.3**	10%	8%	4.7	2.9	**7.6**
2027	124	116	2	1.5	75%	50%	30%	23%	14.0	8.7	**22.7**	70%	53%	32.6	20.3	**52.9**	15%	11%	7.0	4.4	**11.3**
2028	124	116	2	1.5	75%	50%	35%	26%	16.3	10.2	**26.4**	80%	60%	37.2	23.2	**60.4**	20%	15%	9.3	5.8	**15.1**
2029	124	116	2	1.5	75%	50%	40%	30%	18.6	11.6	**30.2**	90%	68%	41.9	26.1	**68.0**	25%	19%	11.6	7.3	**18.9**
2030	124	116	2	1.5	75%	50%	50%	38%	23.3	14.5	**37.8**	100%	75%	46.5	29.0	**75.5**	30%	23%	14.0	8.7	**22.7**
2031	124	116	2	1.5	75%	50%	60%	45%	27.9	17.4	**45.3**	100%	75%	46.5	29.0	**75.5**	40%	30%	18.6	11.6	**30.2**
2032	124	116	2	1.5	75%	50%	70%	53%	32.6	20.3	**52.9**	100%	75%	46.5	29.0	**75.5**	50%	38%	23.3	14.5	**37.8**
2033	124	116	2	1.5	75%	50%	80%	60%	37.2	23.2	**60.4**	100%	75%	46.5	29.0	**75.5**	60%	45%	27.9	17.4	**45.3**
2034	124	116	2	1.5	75%	50%	90%	68%	41.9	26.1	**68.0**	100%	75%	46.5	29.0	**75.5**	70%	53%	32.6	20.3	**52.9**
2035	124	116	2	1.5	75%	50%	100%	75%	46.5	29.0	**75.5**	100%	75%	46.5	29.0	**75.5**	75%	56%	34.9	21.8	**56.6**
2036	124	116	2	1.5	75%	50%	100%	75%	46.5	29.0	**75.5**	100%	75%	46.5	29.0	**75.5**	80%	60%	37.2	23.2	**60.4**
2037	124	116	2	1.5	75%	50%	100%	75%	46.5	29.0	**75.5**	100%	75%	46.5	29.0	**75.5**	90%	68%	41.9	26.1	**68.0**
2038	124	116	2	1.5	75%	50%	100%	75%	46.5	29.0	**75.5**	100%	75%	46.5	29.0	**75.5**	95%	71%	44.2	27.6	**71.7**
2039	124	116	2	1.5	75%	50%	100%	75%	46.5	29.0	**75.5**	100%	75%	46.5	29.0	**75.5**	97%	73%	45.1	28.1	**73.2**
2040	124	116	2	1.5	75%	50%	100%	75%	46.5	29.0	**75.5**	100%	75%	46.5	29.0	**75.5**	100%	75%	46.5	29.0	**75.5**

Source: Mott MacDonald estimate

Table D.9: Cumulative energy saving/DSM impact under three scenarios

Table Year	Base case		Aggressive case		Low case	
	GWh	MW	GWh	MW	GWh	MW
2021	13.9	1.7	27.7	3.4	6.9	0.9
2022	27.7	3.4	55.4	6.8	13.9	1.7
2023	41.6	5.1	83.1	10.2	20.8	2.6
2024	55.4	6.8	110.8	13.6	27.7	3.4
2025	69.3	8.5	138.5	17	34.6	4.3
2026	83.1	10.2	166.2	20.4	41.6	5.1
2027	97.0	11.9	193.9	23.8	48.5	6.0
2028	110.8	13.6	221.6	27.2	55.4	6.8
2029	124.7	15.3	249.3	30.6	62.3	7.7
2030	138.5	17	277.0	34	69.3	8.5
2031	148.5	18.7	297.0	37.4	74.3	9.4
2032	158.5	20.4	317.0	40.8	79.3	10.2
2033	168.5	22.1	337.0	44.2	84.3	11.1
2034	178.5	23.8	357.0	47.6	89.3	11.9
2035	188.5	25.5	377.0	51	94.3	12.8
2036	198.5	27.2	397.0	54.4	99.3	13.6
2037	208.5	28.9	417.0	57.8	104.3	14.5
2038	218.5	30.6	437.0	61.2	109.3	15.3
2039	228.5	32.3	457.0	64.6	114.3	16.2
2040	238.5	34	477.0	68	119.3	17.0

Source: Mott MacDonald estimates based on DNV-GL 2014

Table D.10: Projected final electricity demand and generation requirements for Base, High, and Low scenarios in GWh

Year	Base Scenario		High Scenario		Low Scenario	
	Electricity Demand	Generation Requirement	Electricity Demand	Generation Requirement	Electricity Demand	Generation Requirement
2020	943	1011	943	1011	943	1011
2021	952	1020	985	1056	912	978
2022	969	1038	1043	1118	887	950
2023	993	1064	1118	1198	866	928
2024	1016	1089	1190	1275	845	906
2025	1049	1124	1283	1375	831	891
2026	1072	1149	1338	1434	835	895
2027	1108	1188	1414	1516	848	909
2028	1193	1278	1499	1607	864	926
2029	1221	1309	1578	1691	878	941
2030	1277	1368	1670	1791	899	963
2031	1314	1409	1688	1810	915	981
2032	1357	1454	1706	1829	932	999

Year	Base Scenario		High Scenario		Low Scenario	
	Electricity Demand	Generation Requirement	Electricity Demand	Generation Requirement	Electricity Demand	Generation Requirement
2033	1395	1495	1725	1849	949	1018
2034	1424	1527	1743	1869	966	1036
2035	1454	1558	1762	1889	983	1054
2036	1464	1570	1764	1891	987	1058
2037	1475	1581	1767	1894	991	1062
2038	1483	1590	1770	1897	995	1066
2039	1492	1600	1773	1900	999	1071
2040	1499	1607	1776	1904	1003	1075

Source: Mott MacDonald

Table D.11: Final electricity demand under Base, High, and Low scenarios in the underlying LINDA model and updated model.

Year	Historic demand	LINDA Model Reference Scenario	LINDA model High Scenario	LINDA model Low Scenario	Base Scenario	High Scenario	Low Scenario
2000	703	0	0	0	0	0	0
2001	735	0	0	0	0	0	0
2002	764	0	0	0	0	0	0
2003	806	0	0	0	0	0	0
2004	831	0	0	0	0	0	0
2005	885	0	0	0	0	0	0
2006	903	0	0	0	0	0	0
2007	941	0	0	0	0	0	0
2008	944	0	0	0	0	0	0
2009	952	0	0	0	0	0	0
2010	960	0	0	0	0	0	0
2011	933	0	0	0	0	0	0
2012	918	0	0	0	0	0	0
2013	912	0	0	0	0	0	0
2014	900	0	0	0	0	0	0
2015	915	0	0	0	0	0	0
2016	944	0	0	0	0	0	0
2017	944	0	0	0	0	0	0
2018	943	0	0	0	0	0	0
2019	945	945	945	945	945	945	945
2020	0	941	941	941	943	943	943
2021	0	959	988	921	952	985	912
2022	0	977	1037	901	969	1043	887
2023	0	996	1090	880	993	1118	866
2024	0	1016	1146	862	1016	1190	845
2025	0	1034	1203	844	1049	1283	831
2026	0	1044	1223	842	1072	1338	835
2027	0	1053	1242	841	1108	1414	848

Year	Historic demand	LINDA Model Reference Scenario	LINDA model High Scenario	LINDA model Low Scenario	Base Scenario	High Scenario	Low Scenario
2028	0	1063	1262	840	1193	1499	864
2029	0	1073	1281	839	1221	1578	878
2030	0	1084	1300	837	1277	1670	899
2031	0	1090	1314	837	1314	1688	915
2032	0	1096	1327	837	1357	1706	932
2033	0	1103	1340	835	1395	1725	949
2034	0	1110	1354	836	1424	1743	966
2035	0	1117	1367	835	1454	1762	983
2036	0	1123	1378	834	1464	1764	987
2037	0	1129	1389	834	1475	1767	991
2038	0	1135	1401	834	1483	1770	995
2039	0	1142	1413	833	1492	1773	999
2040	0	1147	1424	832	1499	1776	1003

Table D.12: Projected electricity demand (GWh) in the Base Scenario by sector

Year	Base Scenario							
	Reference scenario Residential	Reference scenario Hotels & Restaurants	Reference scenario Commercial	Reference scenario Industry	Base scenario EV	Base scenario CL	Base scenario Cooking	Base scenario DSM Savings
2020	351	123	346	121	2	0	0	0
2021	361	126	348	124	5	0	2	-14
2022	370	129	350	128	15	0	4	-28
2023	380	132	353	131	30	1	8	-42
2024	391	135	355	135	43	2	11	-55
2025	401	138	357	138	65	3	15	-69
2026	404	141	360	139	87	5	19	-83
2027	407	144	362	140	118	11	23	-97
2028	410	147	365	141	197	16	26	-111
2029	413	150	367	143	220	23	31	-125
2030	417	153	370	144	264	30	38	-139
2031	418	156	372	144	292	36	45	-149
2032	418	159	375	144	324	42	53	-159
2033	419	162	377	145	352	48	60	-169
2034	420	165	380	145	371	54	68	-179
2035	421	169	382	145	390	59	76	-189
2036	422	172	384	145	405	59	76	-199
2037	422	175	387	145	420	59	76	-209
2038	422	178	389	146	432	59	76	-219
2039	423	181	392	146	445	59	76	-229
2040	423	184	394	146	455	59	76	-239

Table D.13: Projected electricity demand (GWh) in the High Scenario by sector

Year	High Scenario							
	High scenario Residential	High scenario Hotels & Restaurants	High scenario Commercial	High scenario Industry	High scenario EV	Base scenario CL	Base scenario Cooking	Base scenario DSM Savings
2020	351	123	346	121	2	0	0	0
2021	373	130	357	128	9	0	2	-14
2022	396	138	368	135	29	0	4	-28
2023	421	147	380	142	60	1	8	-42
2024	447	156	393	150	87	2	11	-55
2025	475	165	405	158	130	3	15	-69
2026	479	171	413	160	174	5	19	-83
2027	483	177	421	161	236	11	23	-97
2028	487	183	429	163	307	16	26	-111
2029	491	189	437	164	369	23	31	-125
2030	495	195	445	165	441	30	38	-139
2031	496	201	451	166	442	36	45	-149
2032	497	206	458	166	444	42	53	-159
2033	498	211	465	166	445	48	60	-169
2034	499	217	471	167	447	54	68	-179
2035	500	222	478	167	448	59	76	-189
2036	500	227	484	167	450	59	76	-199
2037	500	232	490	167	451	59	76	-209
2038	501	237	496	167	453	59	76	-219
2039	501	242	502	168	454	59	76	-229
2040	501	247	508	168	455	59	76	-239

Table D.14: Projected electricity demand (GWh) in the Low Scenario by sector

Year	Low Scenario							
	Low scenario Residential	Low scenario Hotels & Restaurants	Low scenario Commercial	Low scenario Industry	Low scenario EV	Base scenario CL	Base scenario Cooking	Base scenario DSM Savings
2020	351	123	346	121	2	0	0	0
2021	345	119	337	120	4	0	2	-14
2022	338	116	328	119	10	0	4	-28
2023	331	112	320	117	18	1	8	-42
2024	325	109	312	116	26	2	11	-55
2025	319	106	304	115	39	3	15	-69
2026	321	105	300	116	52	5	19	-83
2027	323	105	297	116	71	11	23	-97
2028	325	105	293	117	92	16	26	-111
2029	327	104	290	118	111	23	31	-125
2030	329	104	286	118	132	30	38	-139
2031	330	104	284	119	146	36	45	-149
2032	331	105	282	119	160	42	53	-159
2033	332	105	279	119	174	48	60	-169

Year	Low Scenario							
2034	333	106	277	120	188	54	68	-179
2035	334	106	275	120	202	59	76	-189
2036	334	107	273	120	216	59	76	-199
2037	334	108	272	120	230	59	76	-209
2038	335	109	270	120	244	59	76	-219
2039	335	110	268	120	259	59	76	-229
2040	335	111	266	120	273	59	76	-239

E. Resource Options Evaluation Data

The resource options evaluation is done on the basis of LCOE, which is a constant value that can be thought of as the average minimum price in which the electricity generated by the asset is required to be sold at, in order to offset the total costs of production over its lifetime. Calculating the LCOE is related to the concept of assessing a project's net present value.

The starting premise is that the sum of the present value of LCOE multiplied by the energy generated should be equal to the present valued costs by definition. Rearranging the mathematical expression of this premise and solving and simplifying for LCOE yields the famous equation below:

$$(1)\ LCOE = \frac{\sum_{t=0}^{T}\left(\frac{Cost_t}{(1+r)^t}\right)}{\sum_{t=0}^{T}\left(\frac{Energy_t}{(1+r)^t}\right)}$$

While LCOE is a useful metric in assessing a project's viability, there are some major drawbacks to this method when carrying out energy system planning due to a number of simplifications of the method:

- By definition, the LCOE calculation spreads cost evenly across an asset's lifetime but does not consider the value of an asset. Value needs to consider time of generation in relation to demand and put it into context of the rest of the power system, which requires holistic system simulation;
- LCOE has to assume how much energy the asset will generate to calculate the cost of energy which depends on its capacity factor (CF). Typically, for the LCOE calculation, the potential energy (or technical maximum CF) is used to evaluate the LCOE, while in practice the CF depends on a number of changing factors, including for example curtailment, demand, merit order position, and system constraints;
- LCOE tends to refer to the cost of energy sent-out (at the power station gate) and so does not take account of the connection costs and the wider system integration costs (in terms of network upgrades, balancing, and reserve costs);

With these caveats in mind, we have evaluated the supply options below, which should be used indicatively for context, but should not be used to perform system planning. System planning is carried out using a sophisticated power system simulation and optimisation software and is presented further below. One reason is that the picture may change when plant is mostly part-loaded, and heat rates (efficiencies) vary; we used the full-load efficiencies for the following analysis only.

The table below summarises key cost assumptions developed for this study as well as the annual reduction in capex cost for technologies where learning curves still apply.

Table E.1: Capital Cost Assumptions for Candidate Technologies

Technology	2020 Cost (BBD/kW)	Cost Decay per Year
Medium Speed Rec. Engines	2,904.00	0%
Gas Turbines	2,471.00	0%
Woody Biomass	10,032.00	0%
Landfill Gas	7,075.00	0%
Municipal Waste	24,000.00	0%

Technology	2020 Cost (BBD/kW)	Cost Decay per Year
On-shore Wind	4,208.57	4.2%
PV (Ground Mounted)	3,121.31	8.4%
Concentrated Solar Power (CSP) – 12 hours	15179.79	4.2%
Concentrated Solar Power (CSP) – 15 hours	16602.894	4.2%
Concentrated Solar Power (CSP) – 18 hours	17,788.82	4.2%
Batteries (1h)	904	7%
Batteries (2h)	1481.28	7%
Batteries (3h)	2056.55	7%
Batteries (4h)	2631.82	7%
SCO	400	0

Source: Mott MacDonald

Technologies discounted at this time

Certain technologies such as hydrogen or natural gas, were excluded from the analysis as they were deemed not suitable for Barbados. In particular:

- Green hydrogen production and storage is not a proven and mature technology at this point, as only a few pre-commercial installations exist around the world. Further it is not expected to be matured within the timeframe of the IRRP; up to 2030. And the projected cost is very high even after 2040.
- Natural Gas was excluded after discussions with stakeholders, on the basis that building new small-scale natural gas plants is not economical

It should be noted that the purpose of an IRRP is not to prevent developments of technologies but rather provides a framework within to assess value for money. One of our recommendations is to update the IRRP regularly, which will provide the opportunity to consider alternate technologies when economics change or there is sufficient evidence of maturity and use.

F. Generation and Storage Technologies Review

Table F.1: Generation and Storage Technology Review

Technology	Description	Advantages	Disadvantages
Thermal power plant	Low-speed and medium speed reciprocating engines (RICEs) as well as steam and gas turbines (GTs) are available technologies. These can be built on a modular basis and are capable of combusting a wide range of fuels, including bioenergy and hydrogen blends. A mix of these are currently in use in Barbados (although fired by fossil fuels) and form the backbone of power systems for reliable supply.	climate resilient, dispatchable, synchronous, highly space efficient	local emissions, reliance on fuel supply chain, expensive
Solar PV	Solar PV, being a modular technology, can be deployed at a wide range of scales from residential rooftops to large ground mounted solar farms covering hundreds of hectares. Siting and land-take are not critical issues as compared with wind, so deployment is easier in comparison. The steep cost reductions seen in recent years should continue over the next decade or more, albeit at a slower pace. However, it seems that Barbados is likely to incur a significant (~20%) premium versus the average US price, although the costs will probably follow the same learning curve. Different technologies can be considered, and the systems can also be configured in ways (by adjusting the DC/AC ratios, i.e., the solar fields versus the inverter output) that improve output profiles for better integration into a power system.	cheap, can be distributed which improves resilience, modular, easy to finance, easily deployed, and low maintenance	intermittent and non-synchronous, space requirements, vulnerable to extreme weather
Concentrated Solar Power (CSP) with Storage	CSP is a proven technology, although not widely deployed due to cost. For CSP to be considered economically feasible in a location, it requires a GHI of 2000kWh/m2/year or more. For the past five years, Barbados' GHI has ranged between 2100 and 2170kWh/m2/year (see Figure G.11). Therefore, CSP is an economically viable option for Barbados. The advantage of CSP with storage is that it is deployed with a steam turbine, i.e., a synchronous generator, and can usually store significant amounts of thermal power such that the generator can be dispatchable. There are two types of CSP: Central Tower and Parabolic Trough Collector (PTC). Given the maturity of technologies and the applicable scale, PTC is the preferred technology for Barbados. CSP can be equipped with storage tanks enabling 12-18 hours of full load output, which makes the plant largely dispatchable. This means the CSP can contribute to operational reserves and it can also provide inertia and fault level.	dispatchable, synchronous	expensive, vulnerable to extreme weather
On-shore Wind	Wind turbines are a proven technology and can be deployed at small as well as large-scale. Rogers [14] did a siting study which located seven windfarms using either 1 MW or 3 MW Wind Turbine Generators (WTGs) to get an annual yield of 1.1 TWh to 1.6 TWh based on 317 MW and 456 MW installed capacity respectively. In both cases, the Annual Capacity Factor (ACF)	cheap, easy to finance	intermittent, space requirements, vulnerable to extreme weather, visual intrusion, noise

Technology	Description	Advantages	Disadvantages
	was about 40%. Rogers reported that stakeholders preferred the large machines as this reduced the density of towers and therefore the visual intrusion.		
Off-shore Wind	Offshore wind turbines are a proven technology, however there are very few sites for offshore wind given the lack of shallow water around Barbados. There may be space for 30 40 MW over two or three sites but note that the BNEP 2019-2030 envisages a potential capacity of 150 MW. The OTEC Report [6] describes that the proximity to the island (and visual impacts) and the challenges of the steep seabed would need further investigation. Other global examples of steep coastal ridges show cable tension to be a challenge that with present technology may not be overcome in Barbados. The economics of off-shore wind are not favourable versus onshore wind, as the capital costs are substantially higher, and the expected higher yields are unlikely to be material enough to compensate for the capex premium, especially once reduced availability and higher operation and maintenance costs are considered. It is unlikely that for such a small-scale development, significant developer interest would materialise. Until feasibility studies are completed, this technology is assumed to be highly speculative in Barbados due to the specific challenges.	no onshore land requirement	intermittent, vulnerable to extreme weather, expensive, visual intrusion
Floating offshore wind	The Ocean Energy study [6] discusses floating offshore wind due to Barbados' deep coastal waters, however more studies are likely to be required. It is an emerging technology which is being tested in a number of markets (Europe and North America). This would be a promising prospect for Barbados to be able to harness its wind resources to the largest possible extent. Floating offshore wind has been evaluated as having good potential, with the disadvantage of susceptibility to hurricanes and its higher cost. In this study, we view offshore floating wind to still be a speculative option and it will not be included in the model candidates.	no land requirement, access to larger resource	intermittent, vulnerable to extreme weather, expensive, unproven
Hydro pumped storage (HPS	HPS offers the potential for long duration storage if the reservoir is appropriately sized. However, while potential sites have been identified the lack of water and suitable topography and the comparatively small scale of such a project suggests that HPS would be costly to develop in Barbados. There could be possible synergies between storm water and agriculture. The long development lead times and the prospect of environmental objections suggests that this option cannot be regarded as likely without government participation. In this study, we consider HPS to still be a speculative option pending more detailed feasibility studies and it is not included in the model candidates.	cross-sector benefits, dispatchable, synchronous, long-duration storage	environmental impact, cost, difficult deployment, site dependant
Compressed Air Energy Storage (CAES)	CAES would have similar system characteristics to HPS above, however potential in Barbados would have to be assessed on the basis of suitable geographic and geological features. CAES currently has low efficiencies but efficiencies can be improved with a number of different options including integrated thermal and cryogenic cycles.	Dispatchable, synchronous, long-duration storage	unproven, low efficiency, site-dependant

Technology	Description	Advantages	Disadvantages
	In this study, we consider CAES to still be a speculative option pending more detailed feasibility studies and it is not included in the model candidates.		
Battery Energy Storage System (BESS	There is wide range of battery storage technologies available, such as Li-Ion and Vanadium-flow. Flow batteries overcome some of the disadvantages of Li-Ion, such as limited cycling life and duration, but have other downsides. However, BESS is today usually deployed using proven Li-Ion technology, which is very fast responding and therefore can be used for a range of use-cases, including in combination. Li-ion technologies have also been experiencing rapid cost reductions over the last few years and are expected to continue to do so. We consider Li-ion to be applicable to Barbados. BESS are available in different c-rate configurations (power output over duration), typically ranging from 1 (1 MW, 1 MWh) to 0.2 (1 MW, 5 MWh).	dispatchable, fast and responsive, high efficiency, easily deployed	short useful life, chemical disposal and recycling, fire hazards
Hydrogen Storage	Hydrogen can be stored over long periods, potentially in existing infrastructure and in large quantities for seasonal storage. Hydrogen can be combusted in existing thermal synchronous plant or reacted in fuel cells. Although the process is inefficient, the technology is emerging with a number of projects announced for deployment around the world (typically with government support). Costs are expected to reduce significantly from high current levels. One challenge remains for electrolysers to operate efficiently in conjunction with intermittent renewable energy with low load-factors. Although potential developers do exist in Barbados for small scale hybrid RE/hydrogen schemes to firm their installations, it is our view that more field experience is required in this technology to affirm cost and viability. At large scale for long-term storage and use in the wider energy sector, hydrogen production in Barbados appears unlikely to be an option. Given the speculative nature of this option at this stage, hydrogen is not included as a candidate technology.	Dispatchable, synchronous, long-duration storage	water requirements, high-load factor requirements, inefficiency, cost, unproven at utility scale

Source: Mott MacDonald

F.1 Discussion of Feasibility of Energy Storage Technologies

F.1.1 Lithium ion (Li-Ion) batteries

Li-Ion batteries store electrical energy as chemical potential energy using lithium and carbon-based electrodes and is widespread in the consumer electronic sector as well as in the growing electric vehicle (EV) sector. While many variations of the cell chemistry exist, a standard cell is based on a planar or cylindrical design.

During discharge the battery supplies DC power to a power converter which converts it (inverts) to AC. This is achieved by the lithium ions migrating through the porous separator to the anode where it is reduced (combined with electrons). During battery charge the converter produces a slightly higher voltage, allowing power flow into the battery cells. There are variations of Li-Ion chemistries of which the conventional types make use of a liquid electrolyte that assists with the transport of Li-ions to and from the cathode and anode.

A standard Li-Ion battery uses Li transitional metal oxides as the anodes and graphite carbon as the cathodes. The electrolyte is typically a non-aqueous organic liquid that contains dissolved lithium salts and transports the Li ions between the electrodes. The anode and cathode are ionically connected and electrically separated by a micro-porous insulating membrane that acts as the separator. During the charging process, lithium ions are transported from the positive metal oxide host structure through the electrolyte and separator to the cathode electrode, with the reverse taking place during the discharge process. The chemical reactions are highly reversible and have led to its widespread commercial application in the portable electronics market.

The battery is a good candidate for applications that require fast response times, small dimensions, and weight. The systems can achieve high cycling efficiencies (>95%), maintain low standby losses and deliver good tolerance towards cycling. The estimated lifespan of the systems can range up to 15 years with more than 4000 cycles, although the performance reduces over time due to aging by cycling.

The liquid electrolyte gives rise to possible leakage problems if any holes are present in the containment layers of the assembly. Another problem inherent in the design is the formation of Li dendrites that makes the device prone to explosion and requires a sensitive thermal management system. The Depth of Discharge is another factor that can affect the lifetime of the battery and requires that the on-board battery management system control its operation.

Li-Ion battery systems make good candidates for grid support services as the technology has very good energy and power densities ranging from 200 to 500Wh/kg and 150 to 500W/kg with very fast response times (<1s), small dimensions and weight.

Longer duration storage (>6 hours) is less advantageous for Li-Ion battery systems as the storage medium (the batteries) are a significant proportion of the cost of the system and cannot be scaled significantly at low cost independent of the charging devices.

Table F.2: Lithium-ion batteries advantages and disadvantages

Advantages	Disadvantages
• High efficiency ranging between 85 - 90% • Commercially mature • Sub-second response time of 0.15 - 0.25s • Does not suffer from memory effect or severe depth of discharge limitations affecting Lead Acid and other battery technologies. • High energy density • No locational constraints	• Inverter-based (no inertia and low fault level) • Limited cycle life due to degradation of the cell materials during operation (the exact limits will depend on the sub-chemistry and energy capacity and use as well as environmental factors) but typically 4000 cycles or just above 10 years for daily cycling • The technology has had some safety concerns as lithium is highly reactive and flammable and as

Advantages	Disadvantages
• Applications outside of grid connected storage (including electric vehicles) encouraging R&D and further cost reductions due to improvements in the supply chain. • Highly modular	such, the batteries can enter a state called thermal runaway during operation. This phenomenon is usually detected by the battery management system, but failures have been known to occur. • Environmental concerns have been raised from the use of lithium and other materials such as cobalt where supply chains incorporate mining activities with low environmental and ethical standards.

Source: Mott MacDonald

Li-Ion batteries are a technically and commercially proven technology with wide-spread adoption, in particular in applications that support the adoption of variable renewable energy. A system is already deployed in Barbados and further deployment will be essential as the share of intermittent renewable energy in the energy mix increases.

F.1.2 Flow Batteries

Flow Battery storage is based on storing energy in electrolytic tanks based on liquid electrolyte e.g., vanadium or zinc bromine. The approach effectively decouples the power and energy of the system. The energy rating can be changed by varying the capacity of the electrolyte tanks and the power rating can be changed by varying the size and number of cells in the stacks.

The storage system comprises two electrolyte tanks connected to a battery stack where a redox reaction occurs, producing DC power. The DC output of the stacks are connected to the AC grid via power converters and controllers.

During discharge the electrolytes are pumped to the cell where DC electrical power is produced from the electrochemical reaction and the electrolyte is spent. Electrolyte is continuously pumped into the battery stack to ensure adequate pressure is maintained and the reaction can be sustained. DC Power is converted to AC via converters and controllers.

During battery charge the converter supplies DC power to the battery stacks and while the pumps ensure continuous flow of electrolyte to the stacks to enable the electrolytic fluid to be regenerated. Electrical energy is stored as chemical potential energy in the electrolyte phase. Future developments will produce enhanced cell and stack designs that improve performance and reliability and enables further commercialisation of the technology.

Due to the low cost of adding additional energy storage to a system (kWh), flow batteries are likely to be most suitable for long duration storage. Flow batteries are commercially available from companies who are offering commercial Flow battery solutions in the tens of MWs, however there is not yet a mature technology with a proven track record.

Flow batteries do present additional environmental challenges when compared to Li-ion batteries. The liquid electrolyte presents chemical hazards and as such must be contained within the systems and within the site. This is a can be managed with bunding and conventional approaches but does require review for all projects.

Table F.3: Flow batteries advantages and disadvantages

Advantages	Disadvantages
• Sub second response time of between 0.5 - 1 seconds • No locational constraints • ease of scaling the system, good cycle life, and long lifespan (15 to 20 years).	• Inverter-based (no inertia and low fault level) • Relatively low efficiency of between 70-80% compared to other battery systems such as lithium ion. • Relatively high self-discharge ranging from 0.05% - 2%/day associated with continuous operation • Operational hazard present with the electrolytic tank and corrosive elements

Advantages	Disadvantages
	• Relatively low deployment with the technology not yet mature. • high operating costs due to mechanical pumping elements, certain elements being expensive such as the membrane • possible chemical hazards due to the corrosive electrolyte.

Source: Mott MacDonald

This technology should be monitored as it progresses to maturity.

F.1.3 Hydro pumped storage (HPS)

HPS uses the upstream hydraulic potential of a water reservoir as an energy store. Water is held back until the pressurised pipe linked to the downstream area is opened, allowing the water to flow downwards, decreasing in potential energy, and increasing in pressure as the column increases in vertical height. It then goes through a turbine which produces electrical energy.

During charging operation, the reverse occurs with the downstream water being pumped upwards, decreasing in pressure as it ascends to the reservoir. The grid electrical energy used to power the pump is stored as potential energy as the water sits in the reservoir. The storage capacity may be increased by digging a bigger reservoir or a building a higher dam.

Typically, HPS has been used for daily load balancing and have 6 to 8 hours of electricity storage, although there are many projects that have far greater installed capacity.

Table F.4: HPS advantages and disadvantages

Advantages	Disadvantages
• High efficiency ranging between 85 - 90% • Long project lifetimes • Technology does not require toxic or hazardous chemicals • Very mature technology that is well understood and has been built for over 100 years. • If advantageous sites are available can provide very low-cost bulk storage • Has the potential to provide inertia and fault level to the system when generating and even when not (synchronous condenser mode).	• Relatively slow response time (when compared to battery storage) even when in standby which consumes some water • Dependant on natural reservoirs and favourable geographic sites with large head (difference between upper and lower reservoirs) to build. This limits the potential installed capacity. • Has a high environmental impact and can take many years of planning approvals before it is installed. • Long construction lead times • Not modular • The connection to the grid is often far from any connection point or load source, adding to the build complexity and cost.

Although Barbados does have reasonable raised elevations, up to around 300 metres above sea level (MSL), there are not many valleys to dam to make storage ponds at different levels. The island is densely populated which adds to the difficulty of finding suitable dam locations. Generally, with pump storage one would look to have a short but steep distance of less than 1 km. Based upon a high-level review of the islands topography, potential sites resulting in a sufficient head difference of 120 m may be available. However, the gradient on the island implies that distance between such two reservoirs over which water would need to be pumped and released is significant at around 4 km. A conventional HPS in Barbados would therefore be much more expensive than typical schemes.

Alternatively, there are more promising sites for a new variety of pump storage called 'Seawater Pumped Storage' on the Eastern shore hills of the island which would result in around 230 m of head difference. However, the technology cannot be regarded as proven or mature as there is only one currently generating in the world at Yanbaru in Japan (a 30 MW scheme). Specific challenges are presented by the nature of the marine environment which would need to be especially managed, such as corrosion as well as marine growth and fouling all increasing technical and environmental risks associated with such a project that would require storing seawater at elevation.

While technical feasibility at this point remains speculative, it is certain that Barbados is not going to have any low-cost development options for HPS. Since Capex cost are highly site specific and rely on assumptions about feasible technologies, it was concluded that such an option would not be used in the current IRRP until further clarity is obtained.

F.1.4 Compressed Air Energy Storage (CAES)

CAES is based on the principle of pressurised air being used as an energy storage medium.

It comprises a pressurised reservoir (typically subsurface geological formation such as a salt cavern) being used to hold a pressurised medium, typically air, with the air whose flow out of or into the reservoir is the basis on generating or storing electrical energy to/from the grid.

During discharge the air is released from the reservoir into the atmosphere, going through a turbine which converts the piezometric (pressured) energy of the air into electrical energy for the grid. This is done by turning a turbine. The expansion of the air is endothermic (requires the absorption of heat) which necessitates the heating of the air.

During charge the air is pumped into the reservoir, decreasing in volume exothermically (pushes out heat). The air requires cooling to store this at suitable pressures. The electrical energy used to power the pump is converted into the compressed air piezometric energy in the reservoir.

In the projects installed to date the heat released during compression is released to atmosphere. The heat required during expansion is supplied by burning natural gas. A number of developers are seeking to improve the efficiency of CAES by developing an adiabatic (not heat added or taken away) system. In this system the heat released in compression would be stored and added to the air at expansion. This has the potential improve the efficiency of CAES and eliminate the operation CO_2 emissions.

Table F.5: CAES advantages and disadvantages

Advantages	Disadvantages
• Potential to provide many hours or days of stored power. • Technology does not require toxic or hazardous chemicals.	• Theoretical efficiency is around 60 -70% for adiabatic storage which is on the low end compared to other storage technologies. This efficiency is theoretical as no adiabatic storage projects have been built. • Relatively slow response time in the seconds to minutes range due to system component limitations including turbine response time. • Underground CAES is locational constrained to favourable geologies and suitable salt caverns. • While component technologies are mature, the implementation of CAES is immature with limited deployment in the USA and the EU. Only a few test projects have been built with further technological development still to come.

F.1.5 Thermal Energy Storage

Thermal Energy Storage is based on high (and sometimes low) temperature materials used as energy storage mediums.

This comprises a heat store holding a thermal medium, e.g., molten salt, contained in a tank that is insulated to minimise thermal leakage. Energy is reclaimed either directly through a heat engine or through a heat exchanger, acting as a boiler in a conventional power plant cycle.

The basic concept of the technology is similar to concentrated solar power where molten salt is heated by reflected sunlight. The heat from the molten salt is then used to generate power using a steam turbine. The difference in thermal energy storage is that the heat comes from the electrical grid (either using resistors or heat pumps). Additional thermal energy may also come from waste heat.

Table F.6: Thermal Energy Storage advantages and disadvantages

Advantages	Disadvantages
• Potentially low capital cost • Potential to provide many hours of stored power. • Technology does not require toxic or hazardous chemicals. • The components of the technology are mature and well understood • High energy density	• Efficiency ranges between 35% and 60% for projects without waste heat reclamation, up to 65-75% for projects with waste heat reclamation. • Response time is typically in the tens of seconds which is on the lower end for storage technologies • Self-discharge is comparatively higher to other technologies with a discharge rate between 1 and 3% per day. • Requires high temperature operation with potential fire and safety concerns to be addressed • As a standalone technology is not fully mature.

The heat storage technologies are being developed and trialled by Siemens and Google (project Malta). These technologies offer the potential for tens of hours of storage.

This technology has the potential to provide the longer duration storage at lower cost than additional Li-ion batteries and may be used to minimise biofuel consumption. This is particularly true where CSP is used and these technologies can be integrated, e.g., by allowing the super-heating the thermal storage tank with electric heating elements (with electricity supplied from the grid) in addition to the solar thermal collectors typically used.

F.2 Hydrogen Storage

Hydrogen Storage uses surplus electrical energy to generate hydrogen that acts as the energy carrier.

The operation consists of an electrolyser and a storage medium, typically a high-pressure vessel.

During discharge, the hydrogen can be combusted in boilers, turbines, or reciprocating engines to produce electricity in conventional power plants along with natural gas or in a fuel cell can be used to directly convert the hydrogen into electricity and water.

During the charge cycle the electrolyser splits water molecules into oxygen and hydrogen. The hydrogen is then stored or can be injected into the gas network.

Table F.7: Hydrogen Storage advantages and disadvantages

Advantages	Disadvantages
• Good response times ranging between 0.5 - 10 seconds • Low self-discharge between 0.1 - 0.5% per day • No locational constraints • clean precursor (water) and output gases as well as high energy density. • is large storage potential in the gas network	• Very poor efficiency ranging between 32 - 40% • Operational hazard in the form of a hazard zone due to the presence of hydrogen gas • Technology is still quite immature and not widespread however, it is accelerating as seen in projects such as the plant being built in Rhineland, Germany by Shell

Advantages	Disadvantages
	• Regardless of how it is reconverted back to electricity, include high capital cost and relatively short life cycles of the electrolysers and fuel cells

The overall round-trip-efficiency is low at well under 50% with 30-40% losses at both the charge and discharge cycles. Due to this low efficiency hydrogen is typically only deployed in applications where the alternatives are expensive and the advantages such as the low cost of additional hours of storage and the portability of storage medium are important. In Barbados this could apply for long duration storage (day and weeks) where hydrogen created using energy from renewable replaces the use of biofuels during renewable energy droughts.

Hydrogen can be stored in pressurised tanks and this may be appropriate for a few days' supply however if many days/ weeks of supply needs to be held then then underground cavern may be preferred. Hydrogen can also be stored as a liquid, but this is an expensive option and incurs further losses. The major environmental risk is that of fire, with hydrogen being a fire hazard that requires careful control and management on all sites.

Green hydrogen production with storage is currently not a proven technology, and is not expected to be matured within the timeframe of the IRRP. Current global installed electrolyser capacity is ~200 MW. With several new projects announced around the world, it is expected that in the next five years there could be a total capacity of 18 GW. Despite this potential high-capacity growth of electrolysers, the cost of Hydrogen storage using electrolysers is expected to still be relatively high by 2030, as indicated in Table 6.2. Inefficiency of power plants in Barbados intensifies the need for more renewables and exacerbates land issues further. Unless Hydrogen is used in existing dispatchable plant such that RE overplanting can be minimised, it will require a very large-scale Hydrogen economy in Barbados, which is unlikely to be an option before 2030. Therefore, Hydrogen storage has not been considered as an option in this IRRP.

G. Generation Planning Data

G.1 Assumptions

The IRRP spans a 10-year horizon from 01/01/2021 to 31/12/2030 which is the timeframe over which the BNEP 2019-2030 is set out to be implemented. The three scenarios investigated are summarized below.

The robustness of the results of each scenario were tested with various sensitivities. The range of values used for each planning parameter in the sensitivity analysis is described in section G.1.1 below. The high and load demand assumptions can be found in section 4 above.

Table G.1: Planning Scenarios

ID	Scenario	Description
1	Least-cost plan (LCP)	Baseline scenario without policy intervention for reference. Carbon is priced for accounting purposes but otherwise externalised, i.e., not a driver for build and dispatch decisions.
2	Carbon Cost internalised (CO2)	Policy intervention implemented via a Carbon Price. The Carbon Price is internalised into build and dispatch decisions.
3	Forced Firm Renewable Scenario with Carbon Cost internalised (FRES)	Policy intervention implemented via a Carbon Price. The Carbon Price is internalised into build and dispatch decisions. In addition, firm renewable resources are enforced into the plan as follows: • A maximum of two Biomass plants of 10 MW each or a minimum of one Biomass Plant of 10 MW can be built, one of which must be built by 2025. • A maximum of five Landfill Gas plants of 1 MW each can be built from 2023 and must be built by 2025. • A maximum of one Waste to Energy plant of 8 MW can be built from 2023 and must be built by 2025. A choice must be made between a baseload or a more flexible technology type.

Source: Mott MacDonald

Table G.2: Scenario sensitivity matrix

Scenario name	Load High	Load Low	Capex High	Capex Low	WACC High	WACC Low	Fuel Price High	Fuel Price Low	Carbon Price High	Carbon Price Low
LCP[10]	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
CO2	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
FRES	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

Source: Mott MacDonald

G.1.1 Economic planning parameters

G.1.1.1 Currency and exchange rates

Note that all expressions of currency are 2020 real-terms in Barbadian Dollars (BBD) at a fixed exchange rate to the United States Dollar (USD) of 2.2:1 based on the Purchasing Power Parity (PPP) rate unless otherwise stated and therefore exclude inflation or currency devaluations.

[10] As the Carbon Price is for Accounting Purposes only and not used in build or dispatch decisions, there is no impact on the plan from a Carbon Price Sensitivity.

All expressions of NPV and specifically referenced as NPV in the document are present values of cost.

G.1.1.2 Discount rate

The discount rate applies to all cash flows over the study horizon and is used in order to calculate the NPV of these cashflows, which include cost of fuel procurement and amortisation payments for capital expenditure across different years. The NPV of the sum of all the future cost is the objective value, which is to be minimised. The discount rate is not the same as the weighted average cost of capital (WACC). A discount rate typically reflects a social time preference, which can be approximated by the real economic growth rate. A WACC reflects the cost of funding investment.

We have chosen a constant discount rate of 2% based on our review of available economic data for Barbados.

G.1.1.3 WACC

An undifferentiated real WACC of 5% is used based on data received by MESBE from recent unsolicited project proposals in 2019/2020 from developers in Barbados. The rates appear low for some of the technologies compared to our expectations but appropriate for others. However, there was no clear trend across technologies (rather across developers) that allowed for us to apply any differentiation with any certainty.

The high and low WACC used in the sensitivity analysis is 8% and 3% respectively.

G.1.1.4 Capital costs

Capital cost assumptions for the candidate technologies are reported as overnight costs in keeping with industry practices. Overnight capital cost is the upfront investment cost of construction and associated site works and preparatory studies/ licensing fees etc., as stated at the final investment decision. Overnight costs exclude any escalation in costs not built into the initial estimate or interest during construction. In practice for mature modular technologies like reciprocating engines, wind, solar PV, and batteries these overnight costs are close to all-in outturn costs. As mentioned before certain technologies are projected to experience a cost decrease in the future as they mature.

Appendix E, lists out capex assumptions in detail. All capital costs are varied by 10% for the high and low capex sensitivities.

G.1.1.5 Carbon price

Carbon price assumptions are based on those suggested by the Stern-Stiglitz CPCL report (2021) [61]. The report suggests that the carbon price charged should be in line with the Paris agreement temperature target. Therefore, the recommended carbon price is 40-80 USD/tCO_2 by 2020 and 50-100 USD/tCO_2 by 2030. Due to the urgency of implementing climate change mitigation and decarbonization measures as well as to align with the BNEP, we have agreed a carbon price of 80 USD/tCO_2 in 2020 following an exponential increase to 100 USD/tCO_2 by 2030.

For the high and low carbon price sensitivities, 120 USD/tCO_2 and 60 USD/tCO_2 was used.

G.1.1.6 Taxes and duties

Local taxes and duties were not included in this analysis as this is the convention for least cost modelling. Additionally, the rates for taxes and duties over the planning period are unknown and could vary over time, therefore causing distortions to the true cost of the technologies.

G.1.1.7 Fuel price

For this study two main categories of fuels have been considered: conventional fossil fuels (HFO, Jet A1 and Diesel) and bio-sourced fuels (Biomass, Land Gas and Biodiesel).

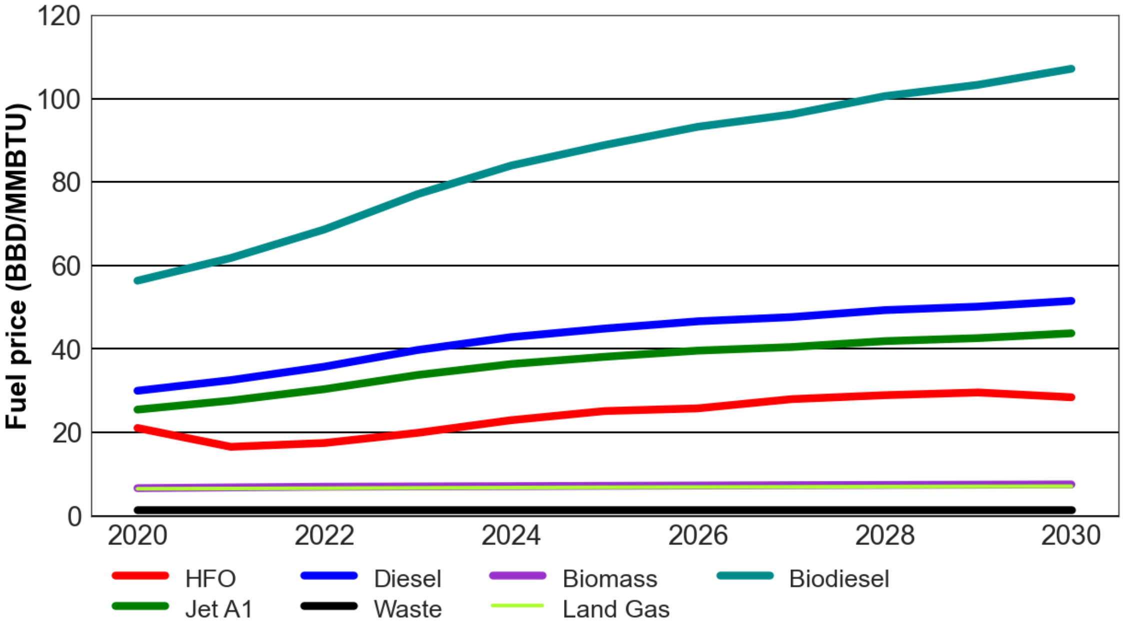
The price reference for the fossil fuel's prices was set by the latest Energy Information Administration (EIA) forecast issued in February 2021 from the US Department of Energy (DOE) [42].

We note that the central price projected for Brent crude increases to USD 73/barrel in 2030 and over USD 87/barrel in 2040 in real (2020) terms. These reference prices are then adjusted using historically observed basis adjustments to provide the delivered prices for BLPC for each product.

No assumptions have been made for coal as coal is not considered a viable candidate generation option due to its environmental impacts and high unit cost at small (sub 50 MW) scale.

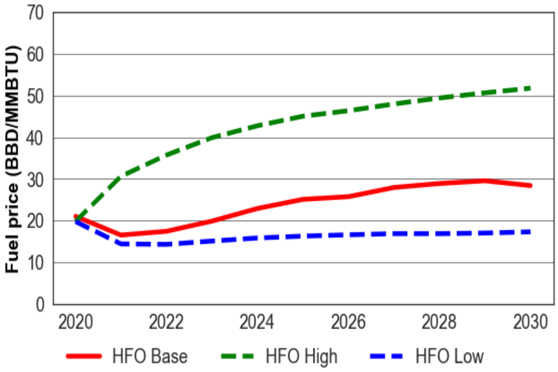
The base/reference fuel forecast is shown by Figure G.1, the high and low-price projections for the conventional fossil fuels and biodiesel can be presented in Figure G. to Figure G.5 Land gas and biomass prices were developed in consultation with local stakeholders. These would be subject to long term purchase contracts and not market fluctuations in global oil prices; therefore, we have not varied these in the sensitivity analysis.

Figure G.1: Base fuel price projections 2020-2030



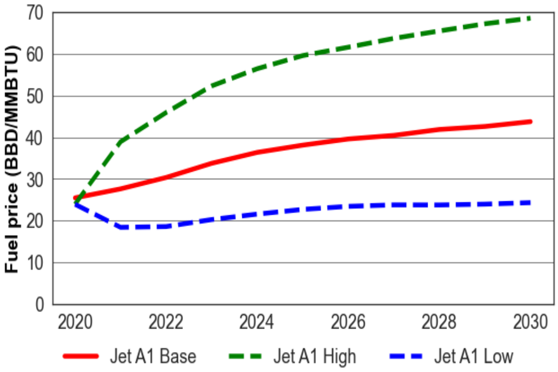
Source: Mott MacDonald based on EIA's January 2021 annual energy outlook

Figure G.2: HFO Price projections



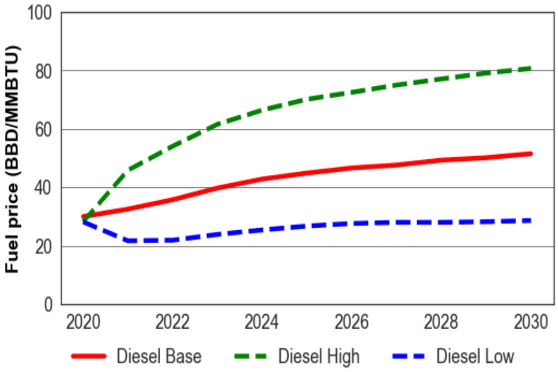
Source: Mott MacDonald based on EIA's January 2021 annual energy outlook

Figure G.3: Jet fuel price projections



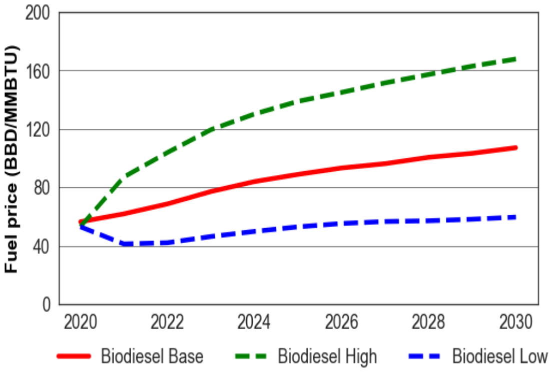
Source: Mott MacDonald based on EIA's January 2021 annual energy outlook

Figure G.4: Diesel price projections



Source: Mott MacDonald based on EIA's January 2021 annual energy outlook

Figure G.5: Biodiesel price projections



Source: Mott MacDonald based on EIA's January 2021 annual energy outlook

The price of biodiesel is linked to the price of diesel, available at a premium of 88%. This is based on the average price premium of biodiesel compared to fossil fuel diesel in the North American wholesale market. Furthermore, we have assumed a 2% increase in premium each year to 2030 as the increasing interest in sustainable aviation fuel and sustainable bunker fuels will drive up premiums for biofuels.

G.1.1.8 Asset retirement

The MESBE system planning model accounts for retirement cost of existing thermal assets based on the FTC approved cost submitted by BLPC in 2019. The model also includes costs related to early retirement in the form of the remaining depreciation at the time of retirement versus the FTC approved depreciation schedule submitted by BLPC in 2019.

G.1.1.9 Asset Ownership and Market Assumptions

All new plant to be built under the IRRP development is assumed to be from IPPs and owner-agnostic where all costs are internalised as per the WACC assumptions outlined above.

Ongoing locked-in cost in the form of depreciation or equity charges for existing assets have not been considered in the model's optimisation decisions in line with standard economic decision-making practices whereby sunk cost are excluded.

It is assumed that all dispatch decisions in the market are done on a least-cost basis subject to technical constraints only with the exception being for existing renewable energy assets which are assumed to receive the same Feed-in Tariff as distributed solar PV built under the Solar Rider Scheme and have to be committed. Therefore, these units are dispatched with priority whenever they can generate.

G.1.2 Technical planning parameters

G.1.2.1 System planning criteria

The reliability criterion for Barbados is given as a Loss-of Load Probability (LOLP) target of 0.274%, or as a Loss of Load Expectation (LOLE) of one day (24 hours) per year (8760 hours). As an aggregate over a year, the equivalent of one day of average load, can go unsupplied.

The Short Term (ST) simulations will be carried out to calibrate the Long Term (LT) and verify that the system with planned build and retirement decisions would be expected to achieve the required reliability standard.

G.1.2.2 Land constraints

Land uptake in the model is a non-binding constraint to consider the land requirement for each scenario. This will be analysed in conjunction with other impacts in the multi-criteria analysis (see section 9). The land requirement of each technology is shown in section 5.2.1.

G.1.2.3 Units' conversion to biodiesel

As mentioned in section 3 there is an option to convert existing engines to operate on biodiesel although, this would impose some limitations on operation. Based on the asset assessment, we have determined that the most likely candidates for conversion are D13, D14, D15 and the Resiliency Bridge due to their age and technology type. The model allows for the conversion of these units to operate on biofuel if economic to do so.

G.1.2.4 Primary reserves

The Barbados system's largest infeed loss (n-1) is set at 30 MW, which represents the largest generator contingency (unit size of the single largest generator) as well as the largest infeed contingency (largest single in-feed on the transmission network). This will also be maintained going forward with each single renewable energy plant being a maximum of 30 MW. Therefore, this reserve is defined as a static 30 MW requirement with a timeframe (or response time) of two seconds and a duration of 30 seconds.

This requirement is aligned with the dynamic frequency behaviour in the event of a fault on the system, where at any time, a 30 MW infeed loss could occur, which would immediately result in a frequency drop, only contained by the inertial response on the system over the first two seconds. After two seconds, governor response would be required to provide additional generation to arrest the frequency drop and to restore it over time.

Currently, Under-frequency load shedding (UFLS) is used in emergency situations to provide this type of reserve. In our modelling we have not allowed for the UFLS to provide this reserve in after 2023 which means that an appropriate supply option will be identified. In practice, the customer-experienced reliability of the Barbados system will therefore be expected to improve.

G.1.2.5 Secondary reserves

Secondary reserve was introduced into the model to address intermittency from variable renewable generation. Intermittency plays out over seconds to minutes due to cloud cover or wind calming.

It takes between 6 to 12 minutes (depending on the thermal state of the units, e.g., hot, warm, or cold) for a modern internal combustion engine to start and ramp up to full output. We have therefore assumed a duration of 10 minutes is required for the initial frequency response and a response time of 30 seconds, which follows on from and after the primary reserve.

EVs that are being smart charged can contribute to secondary reserve provision.

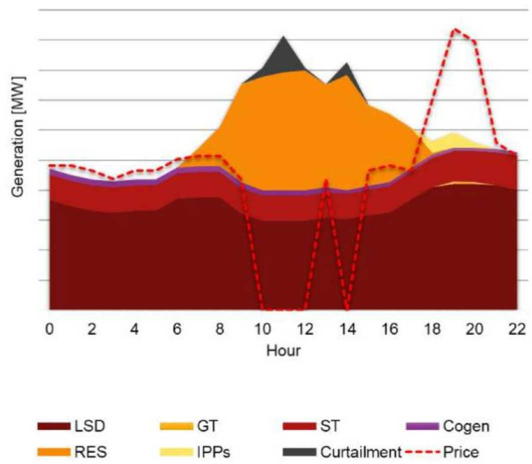
We have carried out an assessment of intermittency that will drive reserve requirements, which is presented in Appendix G.3. This validates the assumptions in the model at present. However, we note that the data upon which the analysis rests is limited. Therefore, the assumptions are conservatively chosen based on a portfolio with at least five different utility scale PV plant sites. It is also not possible with the available data to evaluate whether intermittency across technologies (solar PV & wind) are independent or correlated; meaning whether the reserve requirements are the same or additive. Again, conservatively, we have assumed they are dependent and additive which would require further confirmation.

Secondary reserve requirements are dynamically calculated based on the amount of generation of wind and solar on the system with a timeframe of 30 seconds and duration of 10 minutes.

G.1.2.6 Inertia and fault level constraints reserves

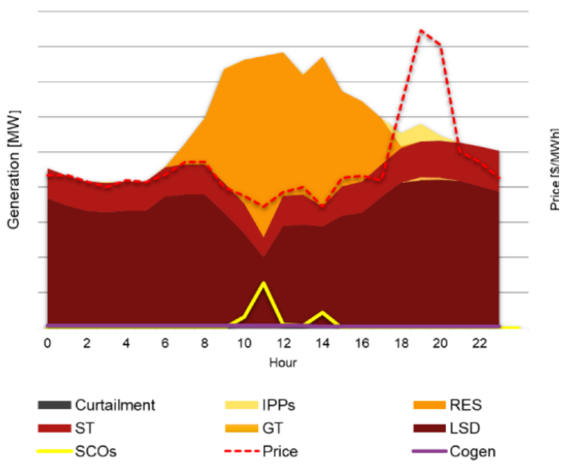
The Barbados transmission system requires 80 MW of synchronous generation for safe operation at all times for fault level provision requirements. This poses an operational constraint that can lead to non-optimal dispatch as shown in Figure G.6 where a minimum amount of synchronous generation needs to be constrained on while PV generation is curtailed. The operational constraint is incorporated into the model and can be mitigated if economic by building and operating Synchronous Condensers (SCOs) as shown in Figure G.7which delivers an ancillary service (here reflected as a reserve) rather than active power.

Figure G.6: Synchronous thermal generation is constrained on and solar PV curtailed (non-economic dispatch) due to binding security constraint



Source: Mott MacDonald

Figure G.7: Economic dispatch achieved by mitigating security constraint (synchronous condenser operation)



Source: Mott MacDonald

Further to this, a constraint is required that enforces to have at least one synchronous generator to be dispatched at all times to provide a reference frequency to the grid (refer to 8 for further details).

G.1.2.7 Electric vehicle smart charging

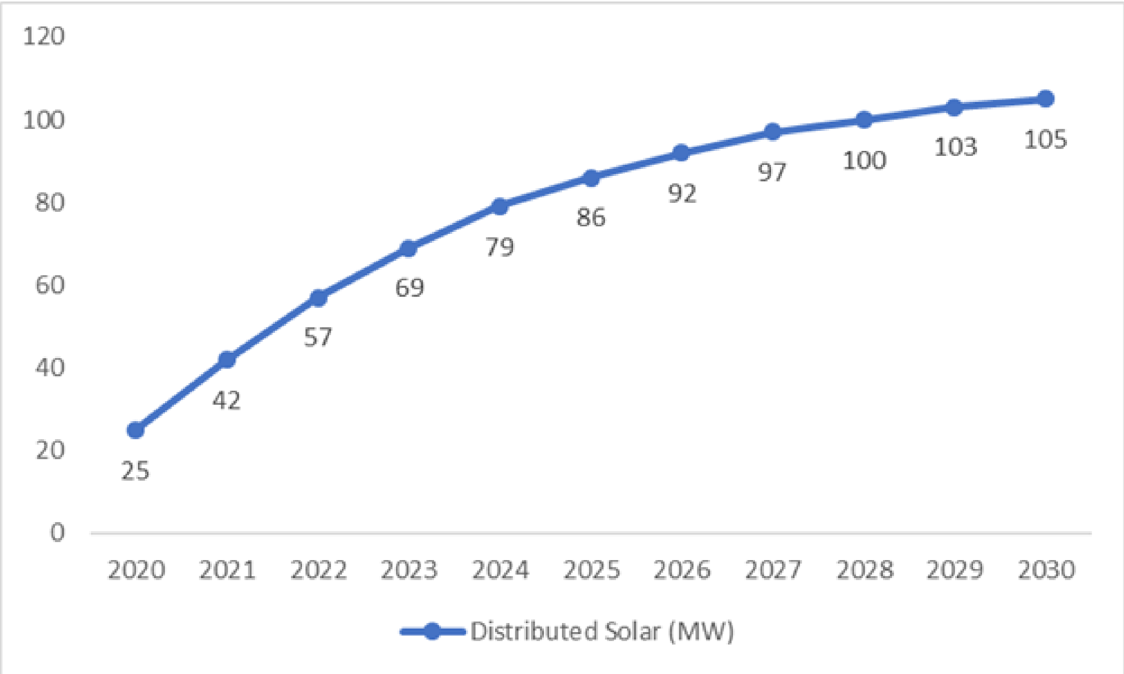
In the base case, 50% of electric vehicle load is assumed to charged using smart charging infrastructure and 100% in the high load case. The load is therefore assumed to be dispatchable as discussed in section 4 and interruptible to provide secondary reserve.

G.1.2.8 Distributed Generation

In order to achieve the policy goals relating to distributed generation assets, we will enforce the builds desired on the assumption that sufficient policy support will be in place to deliver these. Without enforcing these, the optimiser would select the cheapest resources first and only select distributed assets once all other options are exhausted due to externalities not being incorporated. As distributed solar is not competitive with utility scale this will be a forced decision on the supply side.

We will work on the basis of the BNEP 2019-2030 policy target of 105 MW. We will assume an initial rapid uptake in the years leading to 2025, due to existing generous tariff incentives and a slower approach to the 105 MW target towards 2030. The proposed curve and values for distributed solar uptake can be found below:

Figure G.8: Assumed Distributed Solar PV Capacity [MW]



Source: Mott MacDonald based on BNEP

G.1.2.9 Capacity reserve margin

Capacity Reserve Margin (CRM) requirements and firm capacity contributions from each asset type were calibrated to achieve the required and desired reliability of the system. The calibration methodology is described in the methodology section (see section G.2 below).

G.1.2.10 Look-ahead in ST simulation

At present, we are not aware that systematic and state-of-the art forecasting of key variables relevant to system operation is carried out. It is important to do so for optimal dispatch during operations and will impact both cost and reliability of system operation. In order for us to assess a realistic dispatch, we have assumed that a two-day look-ahead (forecast) at hourly resolution is available. This is relatively easily achieved today with sufficient accuracy and therefore is assumed to be a given for this study. With increasing penetration of variable renewable energy sources, it will be critically important to be able to forecast renewable energy output and demand on the transmission network as accurately as possible.

G.2 Methodology

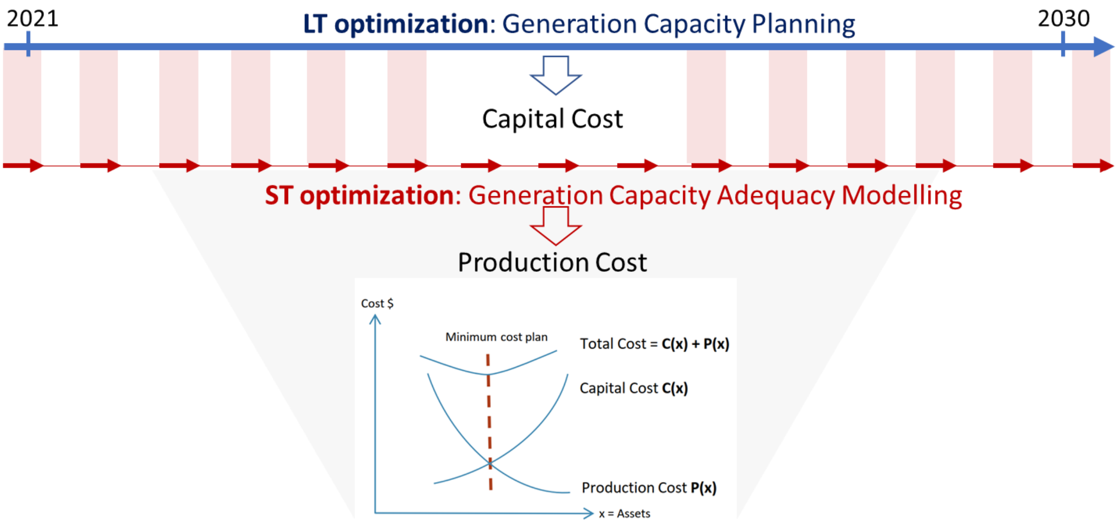
G.2.1 Approach overview

The expansion modelling is done as a constrained least-cost capacity expansion optimisation problem of the Barbados island system using the Long-Term (LT) planning module in the industry leading energy optimization software PLEXOS. Each expansion plan result (set of capacity builds and retirements) was then inputted into subsequent simulation phases of the PLEXOS software to perform detailed hourly simulation of the system which is used to validate and calibrate the LT-Plan. The modelling methodology consists of the following steps that are re-iterated until the objective is achieved:

1. Generation capacity planning: the first is to model the expansion in the LT-phase over the 10-year optimisation horizon from 2020 to end of 2030 in a single step, i.e., planning is done assuming perfect foresight of all variables involved although in practice dimension-reduction is required for simplifications to keep the mathematical problem solvable.
2. Generation adequacy modelling: the following step is to simulate the solution in the ST-phase (running the projected assessment of system adequacy and medium-term phases in between) in daily steps, which includes the highest level of detail and removes perfect foresight from the equation, over the same horizon to check that the generation capacity was adequate, i.e., that the outturn unserved energy is in line with the regulatory target.

This is visualised below in Figure G.9 with the objective of planning a system that exhibits the optimal investment in assets that minimise the sum of all capital, fixed and operational cost as well as the cost of unserved energy (modelled in LT) and achieves a given target for reliability (in ST simulations).

Figure G.9: Generation planning modelling approach



Source: Mott MacDonald

The term ‘least-cost generation capacity expansion’ refers to the problem of finding the optimal combination of generation new builds and retirements that minimizes the NPV of the total costs of the system (including unserved energy) over a long-term planning horizon. The least cost expansion plan simultaneously solves a capacity expansion and a dispatch problem from a central planning, long-term perspective. The model is set up as an hourly model from which 12 days per year are sampled to be solved chronologically in a single optimisation step of 10 years to co-optimise all building and dispatch decisions simultaneously.

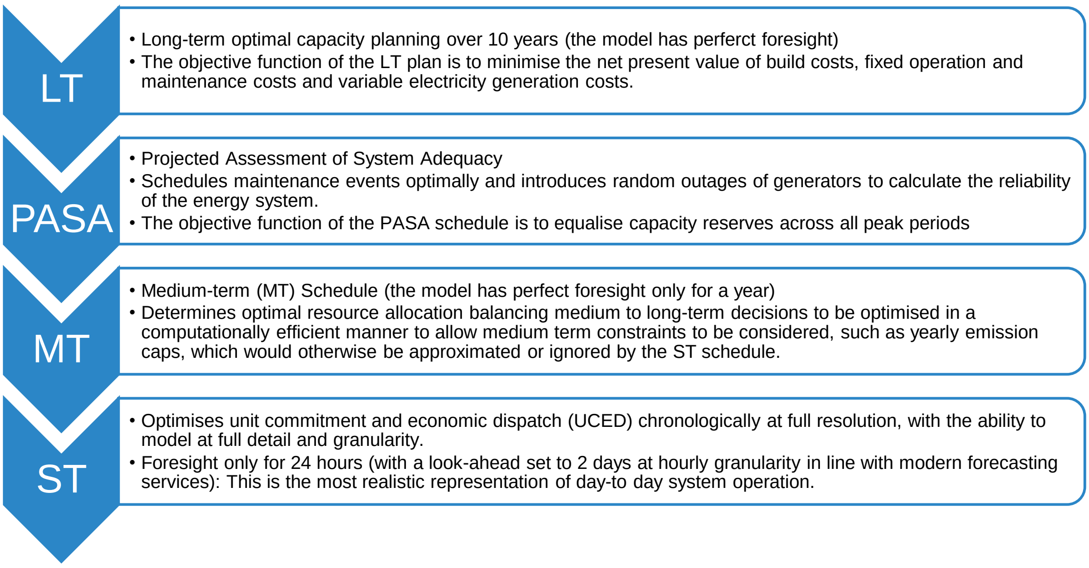
Due to the large computational requirements to simulate the complex nature of high renewable energy penetration system as realistically as possible, we found this approach to give the best balance between computational efficiency and accuracy of results. The sampling is done by PLEXOS automatically and optimally using a clustering approach to develop the most representative days while not omitting critical periods (such as peak periods).

In addition, we chose to co-optimise both the energy dispatch and operating reserve, as the latter will constitute an increasingly large and important part in the system operation and therefore needs to be included in the capacity expansion decisions.

ST simulations were used to validate the LT-plan and re-iterate through a calibration process for the required Capacity Reserve Margin and the firm capacity contribution for each technology such that the system plan achieves the required reliability.

An overview of the phases iterated through and what each of them is used for is presented below:

Figure G.10: PLEXOS simulation phases and optimisation workflow



Source: Mott MacDonald

G.3 Resource analysis

G.3.1 Solar

This section is a solar resource analysis of irradiance and energy output conducted over the period 2000-2019.

G.3.1.1 Overview of historical irradiance data

This section is an analysis of data for GHI (Global Horizontal Irradiance).

Figure G.11: Heatmap to show GHI over 1999-2018, by month

Unit:kWh/m²

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year total MWh/m²	
1999	165	165	193	188	217	186	197	206	183	160	146	146	2.15	1999
2000	157	159	182	198	196	186	209	198	179	170	134	159	2.13	2000
2001	160	168	208	191	206	198	186	199	179	166	164	140	2.16	2001
2002	162	167	195	187	198	186	191	197	168	164	154	167	2.14	2002
2003	164	168	203	173	195	185	189	198	187	164	143	165	2.13	2003
2004	167	174	188	185	177	179	194	196	174	162	129	158	2.08	2004
2005	138	164	204	199	185	165	182	200	188	161	138	156	2.08	2005
2006	156	160	197	207	211	186	195	193	183	162	155	143	2.15	2006
2007	156	168	186	195	215	183	199	183	192	153	161	163	2.15	2007
2008	155	174	205	193	214	177	191	192	164	154	139	143	2.1	2008
2009	159	160	194	194	193	184	179	192	172	177	151	164	2.12	2009
2010	169	165	198	165	198	181	172	187	166	165	154	147	2.07	2010
2011	162	160	190	181	193	177	181	177	162	169	141	136	2.03	2011
2012	165	173	174	194	168	190	196	169	188	167	165	145	2.09	2012
2013	163	165	199	179	190	168	208	186	175	162	156	142	2.09	2013
2014	155	157	199	199	211	186	199	183	174	156	141	155	2.12	2014
2015	165	168	206	199	206	183	199	204	170	170	148	153	2.17	2015
2016	165	167	204	203	194	191	198	206	183	180	127	151	2.17	2016
2017	165	159	195	198	189	172	199	192	162	160	157	147	2.1	2017
2018	152	169	183	193	204	187	193	198	183	170	147	162	2.14	2018
LTA	160	166	195	191	198	183	193	193	177	165	148	152		

Figure G.11 shows the sum total GHI per unit area, split by year and month over the 20-year period. The redder hues represent a great amount of irradiance per square metre for that month, and bluer hues represent a relatively little irradiance.

Along the y-axis are the yearly totals for each year, and along the x-axis are the monthly long-term averages (LTAs). As expected, the months with the least GHI are late autumn and winter months with least sunlight hours, and those with the greatest GHI occur in spring and summer.

Figure G.12: Monthly long-term averages for GHI

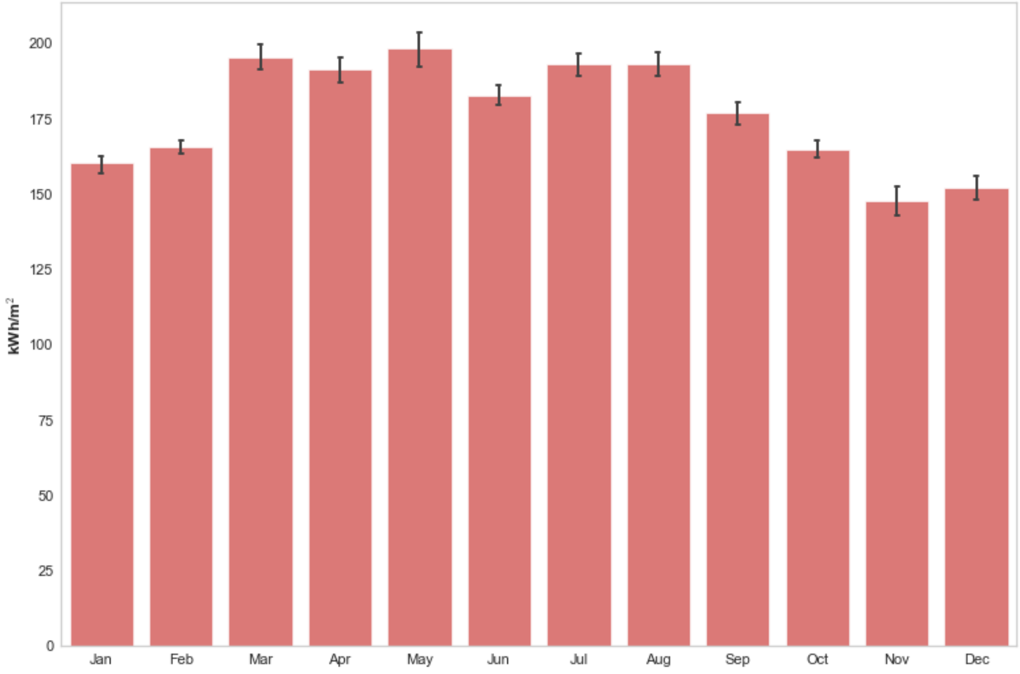


Figure G.12 shows the long-term average of monthly total GHI per unit area for Barbados over the 20-year time period 2000-2019. The graph includes error bars to indicate the spread of the monthly data. Concurring with Figure G.11, the bar chart demonstrates the expected seasonality; whereby the monthly long-term average correlates with the number of typical sunlight hours for each month.

Figure G.13: Yearly average GHI with standard deviation band

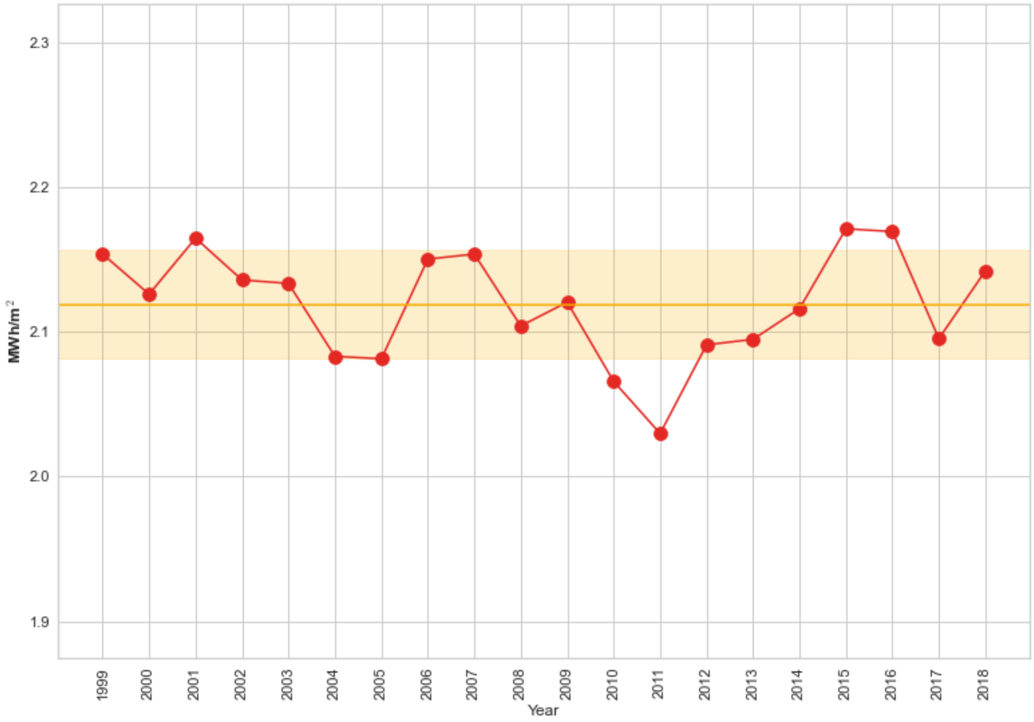
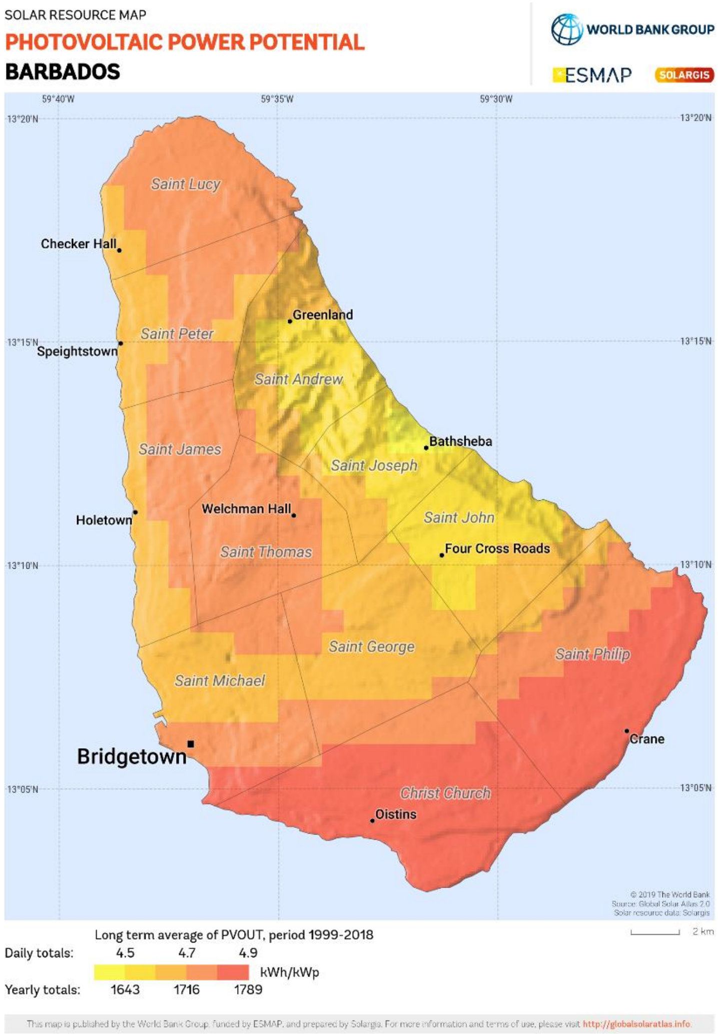


Figure G.13 shows the yearly totals of GHI per unit area for Barbados. It can be seen that the yearly totals closely follow the mean value 2.12 MWh/m².

Figure G.14 is a map showing solar energy yield per unit capacity across different areas within Barbados, using data that spans 1999-2018. After accounting for efficiency of the PV units, the irradiance described in Figure G.13 would reflect in the PV output potential described in Figure G.14

Figure G.14: Long-term average of PV power output, for period 1999-2018



G.3.1.2 Capacity factor

This section looks at the variation in the capacity factor for the solar energy data over the 20-year period. The capacity is assumed to be 1 MWp AC capacity since the exact plant capacities were not provided within the data.

Figure G.15 demonstrates the variation in the capacity factor for each year over the 20-year period. It ranges between 25-27%.

Figure G.15: Interannual variability of yearly average capacity factor

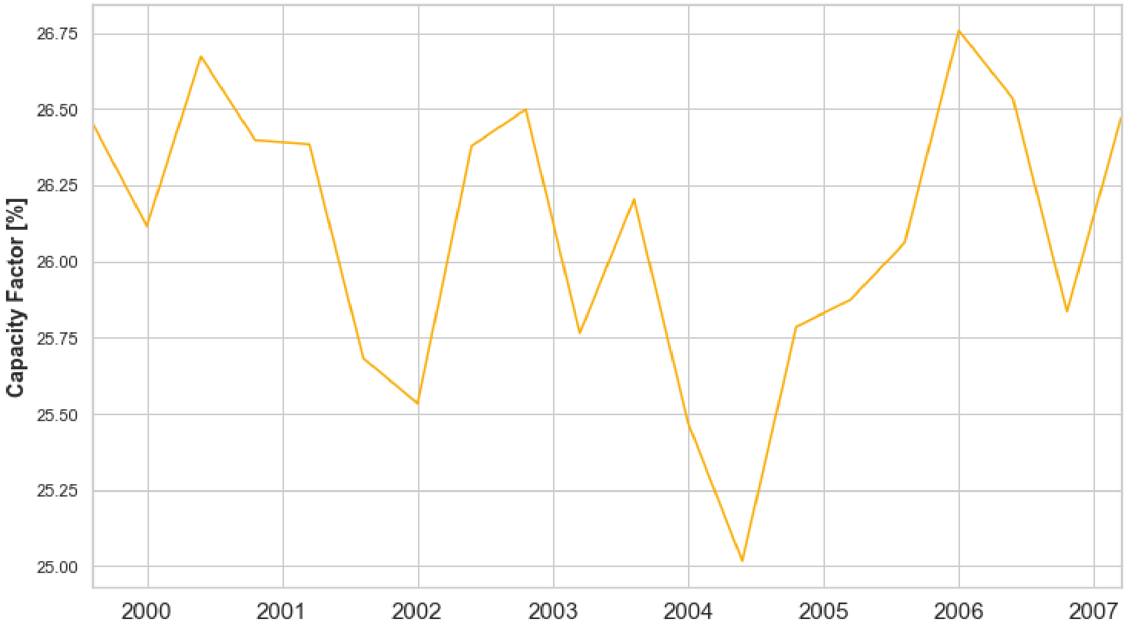
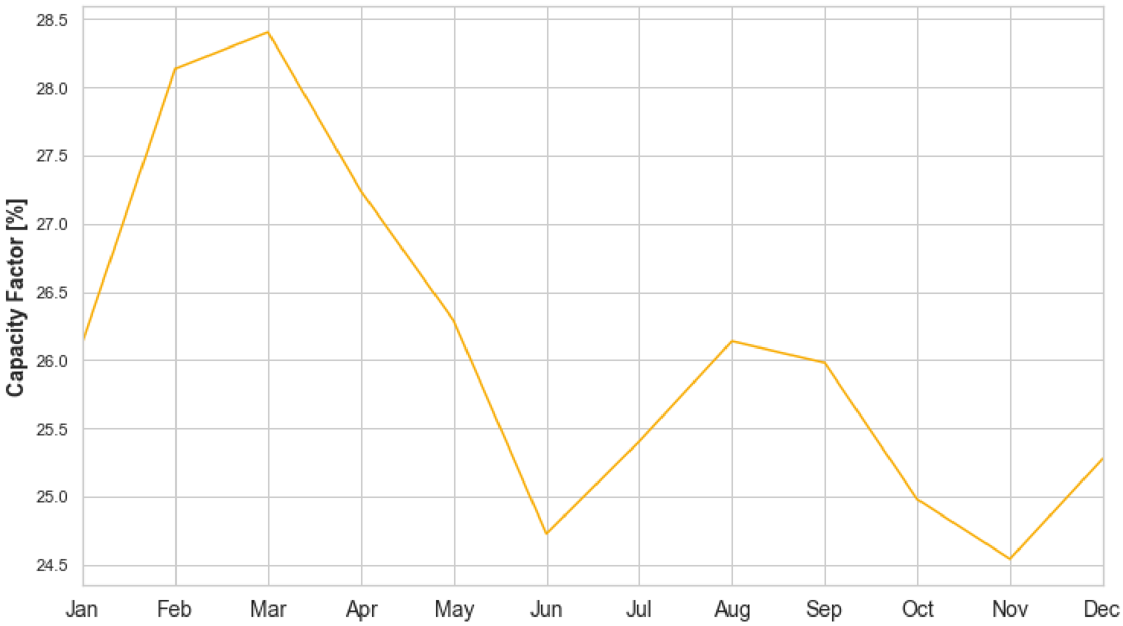


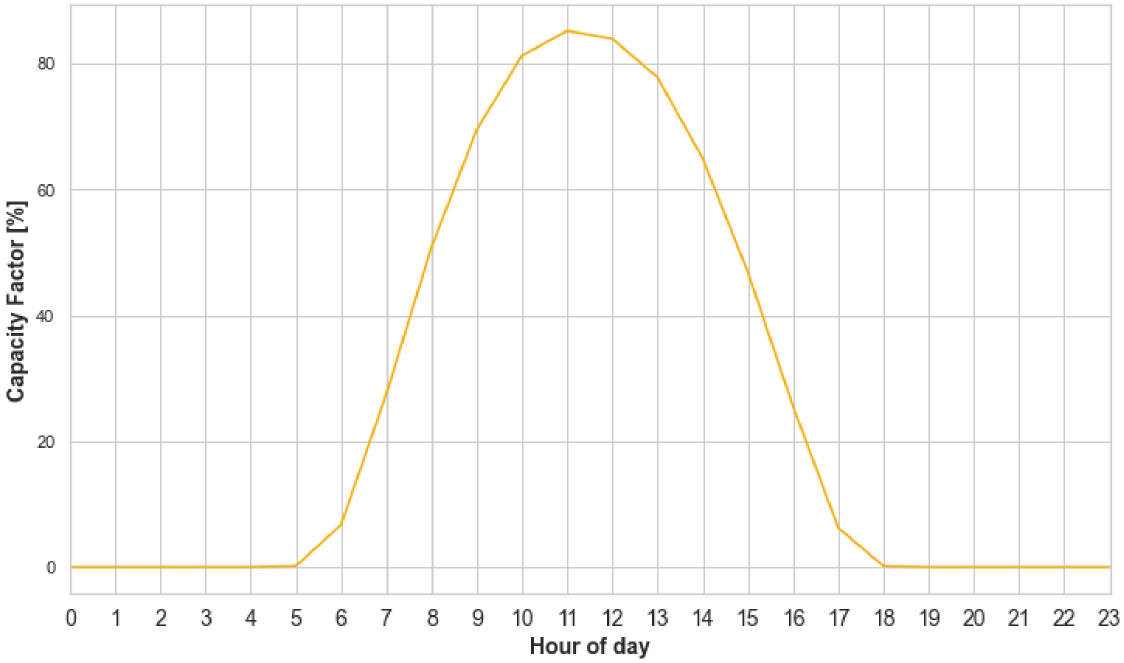
Figure G.16 shows the long-term average capacity factor for each month. The average remains within 24.5-28.5%, although there is a degree of seasonality. The months January through to May generally have the greatest capacity factor implying increased energy yields for this period.

Figure G.16: Capacity factor for solar long-term monthly average



In Figure G.17, the average solar capacity factor on a typical day is highly correlated with the irradiance on a typical day as expected.

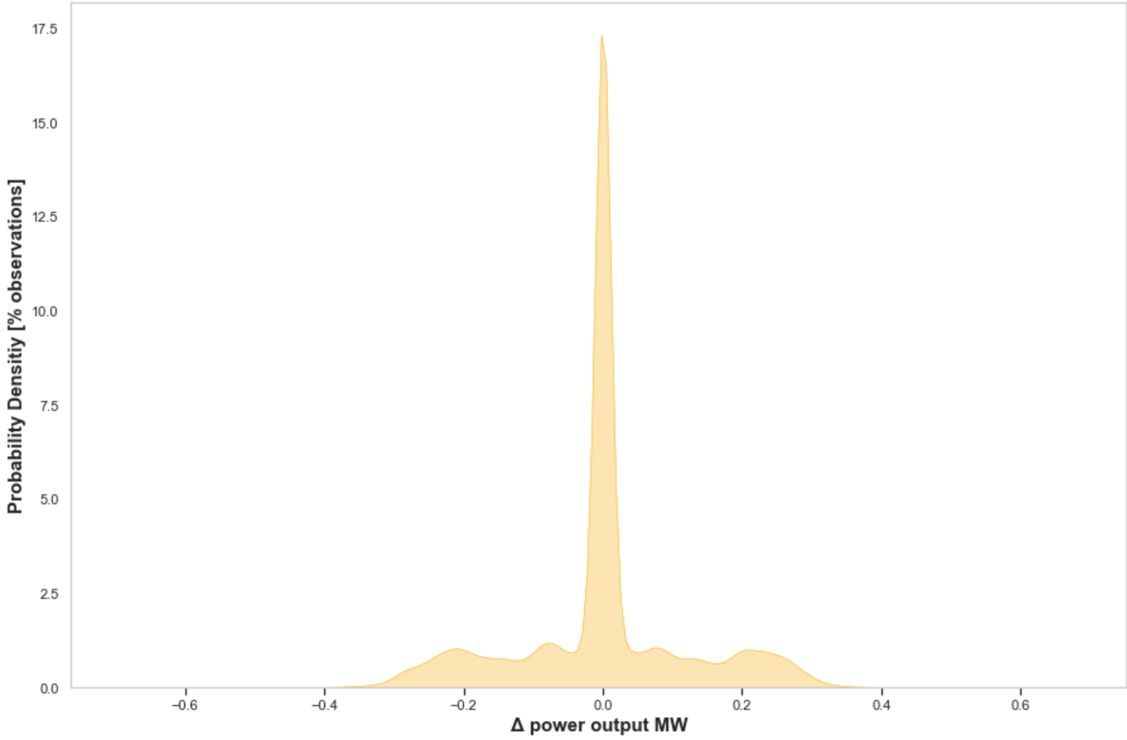
Figure G.17: Capacity factor for solar long-term hourly average



G.3.1.3 Ramping distribution

This section looks at the ramping distribution for solar power output, the data for which is half hourly. In essence, Figure G.18 is showing how much variation in power output can occur across the time interval of half an hour. The sharp peak suggests that the solar power output usually changes by small amounts of less than 0.1 MW, and almost never by more than 0.3 MW, across a half hour time interval.

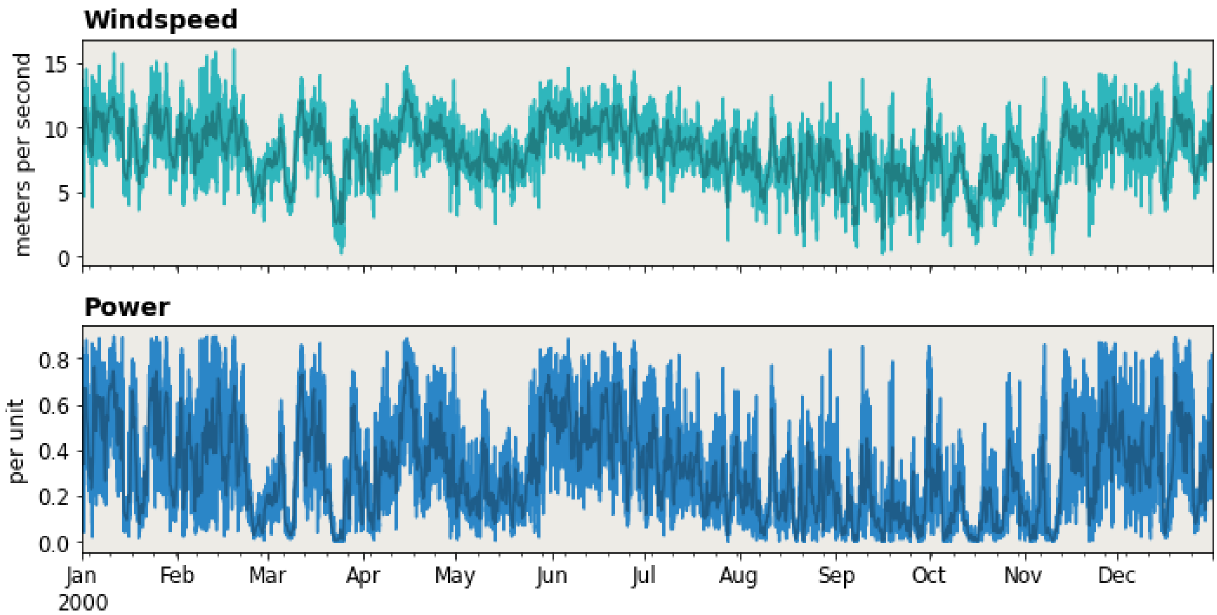
Figure G.18: Ramping distribution of solar power output



G.3.2 Wind

We have analysed wind resource data and conclude that there is good anti-correlation between wind and solar resources. The average capacity factor for wind is estimated to be 22% in line with other studies and open-source data for the region.

Figure G.19: Windspeed and average power timeseries across 10-minute intervals in Barbados



The key metrics for the 10-minute timeseries are displayed in Table G.3 below:

Table G.3: Key statistics from the wind energy profiles recorded in the dataset

	Windspeed (m/s)	Average power (per unit)
Minimum	0.1	0.00
Median	8.3	0.27
Average	8.1	0.30
Maximum	16.1	0.90

It should be noted that we would typically expect to have additional information relating to the windspeed distributions within each 10-minute interval. Specifically, anemometer data can be condensed to express minimum, mean, maximum and standard deviation values for the windspeed distribution or the power generated within each interval. This level of detail was not available for this study.

More specifically, this implies that this study is measuring intermittency on the basis of an aggregating statistic, being the average value for each time interval. As such, it should be noted that it is not possible to infer from this information what is happening to the windspeed, or indeed the power output, within each interval.

Ramping Distributions

Intermittency in this context can be defined as the variability recorded across time intervals. Consequently, we calculated the differences between the values observed across each 10-minute interval. This resulted in two distributions representing the intermittency experienced in relation to windspeed and average power generation in the year 2000. These 10-minute intermittency distributions are analysed in this report alongside the ramping distribution calculated by resampling the timeseries across hourly and six-hourly averages.

The wind resource in Barbados is generally quite variable. Specifically, the probability of there being no change in the average windspeed across 10-minute or hourly intervals is close to 12%. This value is visible in Figure G.20 and it drops by almost half when measured across 6-hour intervals. In other words, there exists an increased likelihood of change to the average windspeed when it is measured across longer time intervals.

This statement is also true of the intermittency observed to power generation, although in this case, as highlighted in Figure G.21, the probability of achieving no change in the average power output across 10-minute, hourly and six hourly intervals is closer to 11%, 10% and 5% respectively.

Interestingly, Figure G.21 also highlights the likely extent of the ramping to the power output. When measured across six-hour intervals there is a 2% probability that the power output could fluctuate by as much as ±15% of the installed capacity. This figure only drops to ±12% when considered over 10-minute intervals, suggesting that the degree of variability in power output is less influenced by time than its likelihood.

Figure G.20: Windspeed ramping distribution

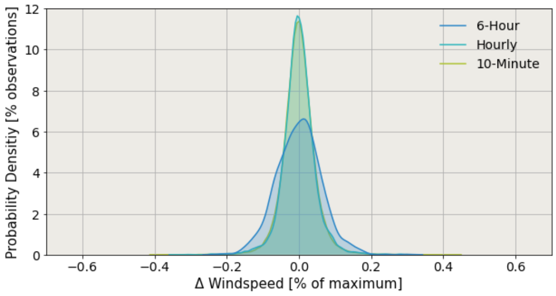
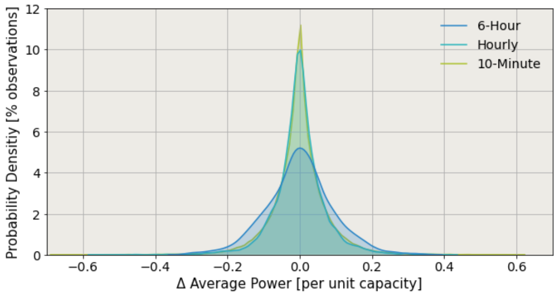


Figure G.21: Average power ramping distribution

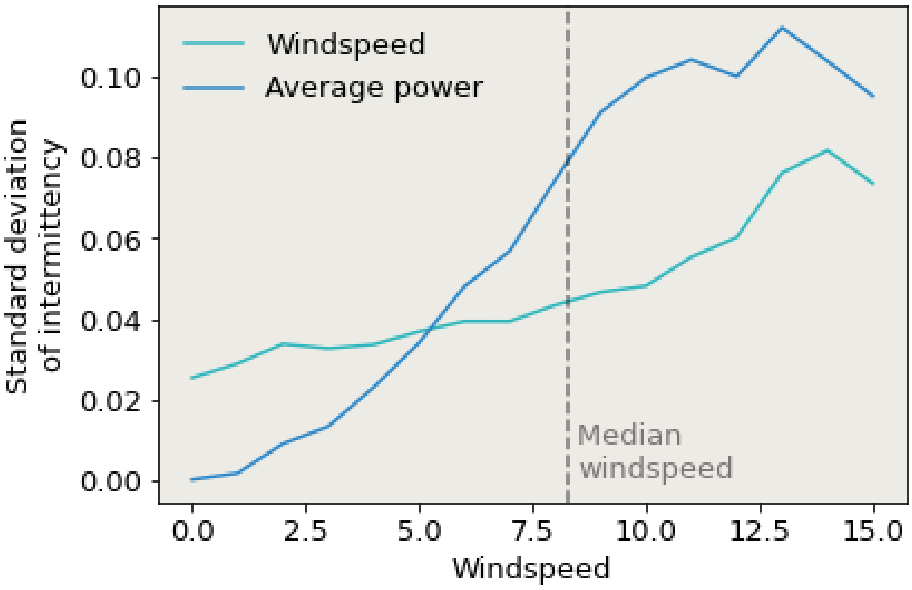


This dataset also highlights that it would be reasonable to expect higher levels of intermittency to the power output during times of higher average windspeeds. Specifically, an R coefficient of 0.97 characterises the relationship between windspeed and power output intermittency, as displayed in Figure G.22.

This figure was generated by calculating the standard deviation of the distribution of ramping measurements recorded given the windspeed. For example, the change in power output was recorded across all intervals in which the average windspeed was between 10 and 11 m/s; and so on for the full range of windspeeds available.

Pragmatically however, it should be noted that intermittency at higher windspeeds can be managed through careful wind turbine selection and through well designed operational procedures. For instance, wind turbine blade can be pitched to change the angle of attack with an impact on the power generation profile. Clever design can therefore be used to mitigate these effects.

Figure G.22: The variability of the ramping changes depending on the windspeed



We would expect however that intermittency would vary for wind turbines at different locations on the island. As such, Mott MacDonald would recommend the cautious assumption that the power output intermittency encountered by a portfolio of wind turbines on the island would be as equally intermittent as the single site.

G.3.3 Solar resource and power generation intermittency

Mott MacDonald was able to analyse timeseries data containing irradiance profiles for six days in May 2014 presented at one-minute intervals. This dataset provides timeseries for five distinct locations on the island of Barbados. It should be noted that the small number of samples days, occurring in the space of about a week, does not allow for the quantification of seasonal changes to intermittency. These profiles are nevertheless useful in providing an overview of the smoothing effects that are inherent to geographical dispersion of solar resources

Intermittency Distributions

Intermittency in this context can be defined as the variability recorded across time intervals. Consequently, we calculated the differences between the values observed across each one-minute interval for the irradiance profile at Garrison and compared it to the ramping of the average irradiance profile that embodies the geographical dispersion effects.

In addition, these one-minute intermittency distributions are analysed below alongside the ramping distributions calculated by resampling both timeseries across 10-minute, 30-minute and hourly averages.

This information is presented in Figure G.23 and Figure G.24, whereby it can be seen that the probability of there being no change in the average irradiance across one-minute intervals is much higher when measured across the island than at a single site: specifically, it is about 15% higher.

As we consider intermittency over longer time horizons however, the figures highlight that the probability of there being no change in the level irradiance drops dramatically across both the single site and total island average intermittency. If we consider, for example, the change in the level of irradiance from one hour to next, Figure G.24 highlights how there is a 97.7% chance that the level of irradiance will have changed by more than 10% across the island. It should be noted that this statistic only considers daylight hours, since irradiance will not change from hour to the next at night-time, for the obvious reason of an absence of sunshine.

Figure G.23: Intermittency at a single site (Garrison)

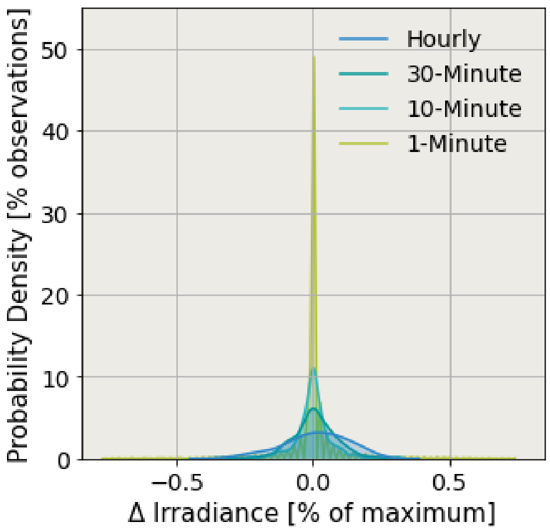
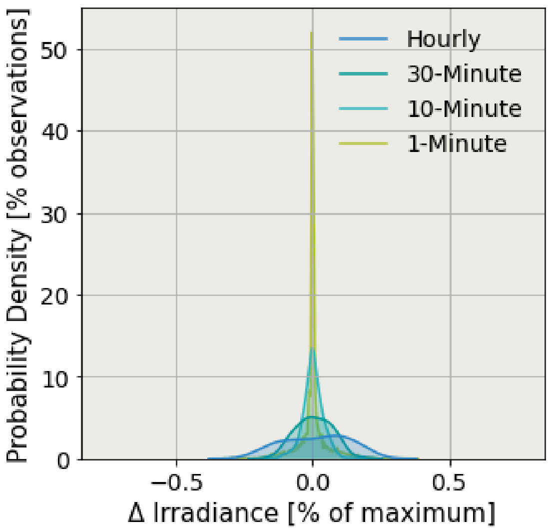


Figure G.24: Intermittency when averaged across the island (5 Sites)



The graphs above highlights how the likely magnitude change in irradiance from one interval to the next. Figure G.25 however, considers the degree of similarity, or correlation, between the intermittency distributions across both time and space. Specifically, this chart plots a linear approximation of the correlation of the concurrent intermittencies based on the distance between the locations at which these were recorded.

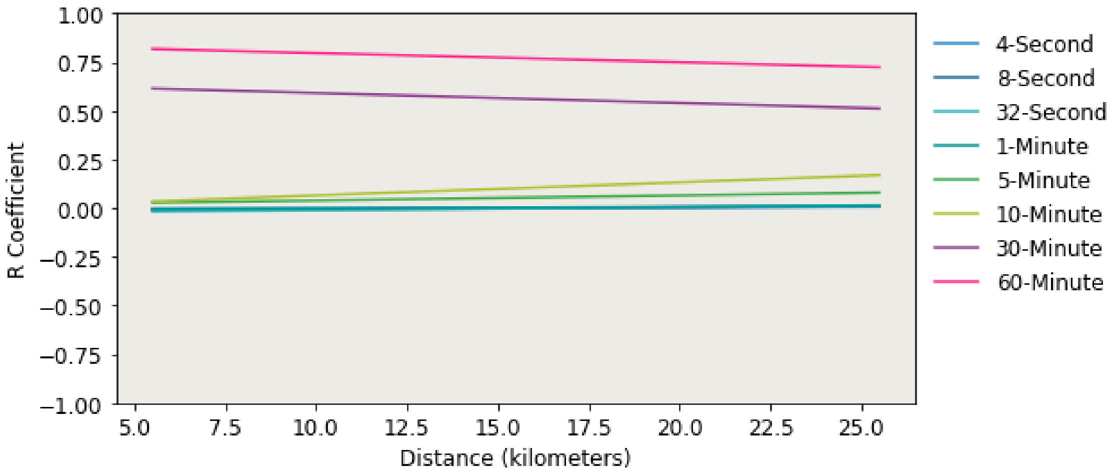
Irrespective of distance, it highlights that the correlation of intermittency increases when considered over longer time horizons. In other words, the position of the sun along with the broader weather system affects each location to a similar extent, although the impact of individual passing clouds can be expected to influence the irradiance measured at different sites by different amounts.

Interestingly, this chart also suggests that distance influences the correlation between the intermittencies recorded across two sites. The further apart the sites are, the;

- more likely their intermittencies will be correlated when measured across five-minute to 10-intervals; and
- Less likely their intermittencies will be correlated when measured across 30-minute to hourly intervals.

These distance effects are only subtle and are not present when considering intervals of one-minute or less. In fact, the resource intermittency of two sites are completely uncorrelated when measured across intervals of one-minute or less.

Figure G.25: Correlation between irradiance profiles when measured at different time intervals



G.3.4 Recommendations

The intermittency analysis presented above provide an illustration of the level of variability that is inherent to the wind and solar resources on the island. Based on the data that was, and equally was not, available to Mott MacDonald, we make the following recommendations:

- Record windspeed and wind generation data at a granular level at different locations on the island to be able to quantify the effects of dispersion;
- Record irradiance solar PV generation data at a granular level at different locations on the island across different seasons (i.e., for a least a full calendar year) to be able to account for intermittency on a seasonal basis.

Note that the use of granular level referred to above implies minute-by-minute intervals with maximum, mean, minimum and standard deviation values available for each interval.

Finally, it should be noted that managing the intermittency from VRE by sizing reserve capacities on the basis of this analysis is a reactive approach to grid balancing. The pro-active approach of forecasting is increasingly becoming available on the market – see our Moata Smart Energy suite of products that includes a Solar Yield Forecaster – whereby managing intermittency is achieved by accommodating for the ever-reducing levels of forecasting error. The reserve dimension will then have to be based on the forecasting error of the aggregate output that is observed in practice.

Not only is this proactive approach expected to deliver substantial costs savings, but it also provides the basis from which a central regulatory authority can begin to mandate the requirement for large scale VRE to delivering grid balancing services.

G.4 Data tables

Table G.4: Refer Figure 7.1: All base scenarios – Cumulative Capacity additions and retirements [MW]

Action	Built	Built	Built	Retired	Retired	Retired
Technology/ Scenario	Sc1 LCP	Sc2 CO2	Sc3 FRES	Sc1 LCP	Sc2 CO2	Sc3 FRES
Battery	204.64	203.89	203.37	5.00	5.00	5.00
BioFuel	-	-	15.00	-	-	-
Diesel	-	-	-	15.00	15.00	15.00
HFO	34.04	34.04	34.04	90.00	90.00	119.70
Jet	-	-	-	-	-	13.00
Solar	180.00	180.00	180.00	-	-	-
Solar Rooftop	80.00	80.00	80.00	-	-	-
Solar Thermal	40.00	60.00	60.00	-	-	-
Waste	-	-	8.00	-	-	-
Wind	161.77	166.81	166.35	-	-	-

Source: Mott MacDonald

Table G.5: Refer Figure 7.2: All base scenario – Carbon emissions [tonnes/year]

Year	Sc1 LCP	Sc2 CO2	Sc3 FRES
2021	742273.6	742080.6	742052.7
2022	575203.1	562292.3	563120.3
2023	503404.9	489498.6	490583.3
2024	437294.8	424160.4	425054.1
2025	384573.3	286059	199468.4
2026	320777	156127	93257.83
2027	272180	119482.6	73281.04
2028	264932.5	118307	74457.63
2029	149599.2	91539.73	57880.22
2030	89514.14	49404.38	38732.13

Source: Mott MacDonald

Table G.6:Refer Figure 7.4: All base scenario – Unserved energy hours [hours]

Year	Sc1 LCP	Sc2 CO2	Sc3 FRES
2021	13	27	25
2022	13	22	19
2023	2	6	4
2024	4	5	2
2025	4	6	11
2026	3	5	6
2027	7	7	2
2028	3	3	1
2029	5	2	0
2030	2	0	1

Source: Mott MacDonald

Table G.7: Refer Figure 7.7: Scenario 1 – Capacity additions and retirements [MW]

Action	Technology	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Built	Battery	-	42.49	100.00	2.04	-	-	-	0.73	27.51	31.87
Built	BioFuel	-	-	-	-	-	-	-	-	-	-
Built	Diesel	-	-	-	-	-	-	-	-	-	-
Built	HFO	34.04	-	-	-	-	-	-	-	-	-
Built	Jet	-	-	-	-	-	-	-	-	-	-
Built	Solar	-	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Built	Solar Thermal	-	-	-	-	-	-	-	-	20.00	20.00
Built	Waste	-	-	-	-	-	-	-	-	-	-
Built	Wind	-	1.77	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Retired	Battery	-	-	-	-	-	-	-	-	5.00	-
Retired	BioFuel	-	-	-	-	-	-	-	-	-	-
Retired	Diesel	-	-	-	-	-	-	-	-	-	15.00
Retired	HFO	-	40.00	12.50	-	12.50	-	-	12.50	12.50	-
Retired	Jet	-	-	-	-	-	-	-	-	-	-
Retired	Solar	-	-	-	-	-	-	-	-	-	-
Retired	Solar Thermal	-	-	-	-	-	-	-	-	-	-
Retired	Waste	-	-	-	-	-	-	-	-	-	-
Retired	Wind	-	-	-	-	-	-	-	-	-	-

Source: Mott MacDonald

Table G.8: Refer Table G.7 - Data further broken down [MW]

Generator/ Battery	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Battery 3H	-	-	50	-	-	-	-	-	-	-	50
Battery 4H	-	42	50	2	-	-	-	1	28	32	155
MSD Resiliency Bridge	34	-	-	-	-	-	-	-	-	-	34
On-shore Wind	-	2	20	20	20	20	20	20	20	20	162
SCO 10	-	-	14	43	17	-	-	-	-	-	74
SCO 5	-	-	-	-	-	7	-	-	-	-	7
Solar CSP1 - 12h TES	-	-	-	-	-	-	-	-	-	20	20
Solar CSP2 - 12h TES	-	-	-	-	-	-	-	-	20	-	20
Solar Utility-Scale 1.3	-	20	-	-	-	-	-	-	-	-	20
Solar Utility-Scale 1.5	-	-	20	20	20	20	20	18	-	-	118
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	2	20	20	42
Total Built	**34**	**64**	**154**	**85**	**57**	**47**	**40**	**41**	**88**	**92**	**701**
D10	-	-	-	-	-	-	-	-	-13	-	-13
D11	-	-	-	-	-13	-	-	-	-	-	-13
D12	-	-	-	-	-	-	-	-13	-	-	-13
D13	-	-	-13	-	-	-	-	-	-	-	-13
D2020	-	-	-	-	-	-	-	-	-	-15	-15
S1	-	-20	-	-	-	-	-	-	-	-	-20
S2	-	-20	-	-	-	-	-	-	-	-	-20

Generator/ Battery	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Trents Storage 1 (2018)	-	-	-	-	-	-	-	-	-5	-	-5
Total Retired	**-**	**-40**	**-13**	**-**	**-13**	**-**	**-**	**-13**	**-18**	**-15**	**-110**

Source: Mott MacDonald

Table G.9: Refer Figure 7.8: Scenario 2 – Capacity additions and retirements [MW]

Action	Technology	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Built	Battery	-	42.61	100.00	2.37	-	0.17	-	1.03	29.15	28.56
Built	BioFuel	-	-	-	-	-	-	-	-	-	-
Built	Diesel	-	-	-	-	-	-	-	-	-	-
Built	HFO	34.04	-	-	-	-	-	-	-	-	-
Built	Jet	-	-	-	-	-	-	-	-	-	-
Built	Solar	-	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Built	Solar Thermal	-	-	-	-	20.00	20.00	-	-	-	20.00
Built	Waste	-	-	-	-	-	-	-	-	-	-
Built	Wind	-	6.81	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Retired	Battery	-	-	-	-	-	-	-	-	5.00	-
Retired	BioFuel	-	-	-	-	-	-	-	-	-	-
Retired	Diesel	-	-	-	-	-	-	-	-	-	15.00
Retired	HFO	-	40.00	12.50	-	25.00	12.50	-	-	-	-
Retired	Jet	-	-	-	-	-	-	-	-	-	-
Retired	Solar	-	-	-	-	-	-	-	-	-	-
Retired	Solar Thermal	-	-	-	-	-	-	-	-	-	-
Retired	Waste	-	-	-	-	-	-	-	-	-	-
Retired	Wind	-	-	-	-	-	-	-	-	-	-

Source: Mott MacDonald

Table G.10: Refer Table G.9 - Data further broken down [MW]

Generator/ Battery	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Battery 3H	-	-	50	-	-	-	-	-	-	-	50
Battery 4H	-	43	50	2	-	0	-	1	29	29	154
MSD Resiliency Bridge	34	-	-	-	-	-	-	-	-	-	34
On-shore Wind	-	7	20	20	20	20	20	20	20	20	167
SCO 10	-	-	22	40	-	-	-	-	-	-	62
Solar CSP2 - 15h TES	-	-	-	-	-	-	-	-	-	20	20
Solar CSP3 - 12h TES	-	-	-	-	-	20	-	-	-	-	20
Solar CSP3 - 15h TES	-	-	-	-	20	-	-	-	-	-	20
Solar Utility-Scale 1.5	-	20	20	20	20	20	20	-	-	-	120
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	20	20	20	60
Total Built	**34**	**69**	**162**	**83**	**60**	**60**	**40**	**41**	**69**	**89**	**707**
D10	-	-	-	-	-	-13	-	-	-	-	-13
D11	-	-	-	-	-13	-	-	-	-	-	-13
D12	-	-	-	-	-13	-	-	-	-	-	-13
D13	-	-	-13	-	-	-	-	-	-	-	-13
D2020	-	-	-	-	-	-	-	-	-	-15	-15
S1	-	-20	-	-	-	-	-	-	-	-	-20
S2	-	-20	-	-	-	-	-	-	-	-	-20

Generator/ Battery	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Trents Storage 1 (2018)	-	-	-	-	-	-	-	-	-5	-	-5
Total Retired	**-**	**-40**	**-13**	**-**	**-25**	**-13**	**-**	**-**	**-5**	**-15**	**-100**

Source: Mott MacDonald

Table G.11: Refer Figure 7.9: Scenario 3 – Capacity additions and retirements [MW]

Action	Technology	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Built	Battery	-	42.68	100.00	1.71	-	-	-	0.72	29.26	29.01
Built	BioFuel	-	-	-	-	15.00	-	-	-	-	-
Built	Diesel	-	-	-	-	-	-	-	-	-	-
Built	HFO	34.04	-	-	-	-	-	-	-	-	-
Built	Jet	-	-	-	-	-	-	-	-	-	-
Built	Solar	-	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Built	Solar Thermal	-	-	-	-	20.00	20.00	-	-	-	20.00
Built	Waste	-	-	-	-	8.00	-	-	-	-	-
Built	Wind	-	6.35	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Retired	Battery	-	-	-	-	-	-	-	-	5.00	-
Retired	BioFuel	-	-	-	-	-	-	-	-	-	-
Retired	Diesel	-	-	-	-	-	-	-	-	-	15.00
Retired	HFO	-	40.00	12.50	-	25.00	12.50	-	-	-	29.70
Retired	Jet	-	13.00	-	-	-	-	-	-	-	-
Retired	Solar	-	-	-	-	-	-	-	-	-	-
Retired	Solar Thermal	-	-	-	-	-	-	-	-	-	-
Retired	Waste	-	-	-	-	-	-	-	-	-	-
Retired	Wind	-	-	-	-	-	-	-	-	-	-

Source: Mott MacDonald

Table G.12: Refer Table G.11 - data further broken down [MW]

Generator/ Battery	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Battery 3H	-	-	50	-	-	-	-	-	-	-	50
Battery 4H	-	43	50	2	-	-	-	1	29	29	153
Biomass	-	-	-	-	10	-	-	-	-	-	10
Landfill Gas	-	-	-	-	5	-	-	-	-	-	5
MSD Resiliency Bridge	34	-	-	-	-	-	-	-	-	-	34
On-shore Wind	-	6	20	20	20	20	20	20	20	20	166
SCO 10	-	-	22	41	-	-	-	-	-	-	62
Solar CSP1 - 15h TES	-	-	-	-	20	-	-	-	-	-	20
Solar CSP2 - 12h TES	-	-	-	-	-	20	-	-	-	-	20
Solar CSP2 - 15h TES	-	-	-	-	-	-	-	-	-	20	20
Solar Utility-Scale 1.5	-	20	20	20	20	20	20	-	-	-	120
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	20	20	20	60
Waste to Energy	-	-	-	-	8	-	-	-	-	-	8
Total Built	**34**	**69**	**162**	**82**	**83**	**60**	**40**	**41**	**69**	**89**	**729**
D10	-	-	-	-	-	-13	-	-	-	-	-13
D11	-	-	-	-	-13	-	-	-	-	-	-13
D12	-	-	-	-	-13	-	-	-	-	-	-13
D13	-	-	-13	-	-	-	-	-	-	-	-13

Generator/ Battery	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
D15	-	-	-	-	-	-	-	-	-	-30	-30
D2020	-	-	-	-	-	-	-	-	-	-15	-15
GT02	-	-13	-	-	-	-	-	-	-	-	-13
S1	-	-20	-	-	-	-	-	-	-	-	-20
S2	-	-20	-	-	-	-	-	-	-	-	-20
Trents Storage 1 (2018)	-	-	-	-	-	-	-	-	-5	-	-5
Total Retired	**-**	**-53**	**-13**	**-**	**-25**	**-13**	**-**	**-**	**-5**	**-45**	**-153**

Source: Mott MacDonald

Table G.13: Refer load Figure [MW]

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
D10	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	-	-
D11	12.50	12.50	12.50	12.50	-	-	-	-	-	-
D12	12.50	12.50	12.50	12.50	12.50	12.50	12.50	-	-	-
D13	12.50	12.50	-	-	-	-	-	-	-	-
D14	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70
D15	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70
D2020	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	-
GT02	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
GT03	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
GT04	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
GT05	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
GT06	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
S1	20.00	-	-	-	-	-	-	-	-	-
S2	20.00	-	-	-	-	-	-	-	-	-

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WH01	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
WH02	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
RE-Riders Solar	41.80	56.47	68.07	77.60	84.10	89.55	93.98	96.37	98.76	100.13
Trents PV01	9.95	9.89	9.83	9.77	9.71	9.65	9.59	9.53	9.47	9.41
MSD Resiliency Bridge	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04
On-shore Wind	-	1.77	21.77	41.77	61.77	81.77	101.77	121.77	141.77	161.77
Solar CSP1 - 12h TES	-	-	-	-	-	-	-	-	-	20.00
Solar CSP2 - 12h TES	-	-	-	-	-	-	-	-	20.00	20.00
Solar Utility-Scale 1.3	-	19.90	19.78	19.66	19.54	19.42	19.30	19.18	19.06	18.94
Solar Utility-Scale 1.5	-	-	19.93	39.79	59.56	79.26	98.88	116.73	116.26	115.79
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	1.67	21.64	41.56
Battery 3H	-	-	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Battery 4H	-	42.49	92.49	94.53	94.53	94.53	94.53	95.26	122.77	154.64
Trents Storage 1 (2018)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	-	-
Peak Load (MW)	159.24	160.37	161.82	163.35	164.96	164.85	164.77	164.70	164.65	165.26
Capacity Reserve Margin (%)	66.73	53.62	65.47	61.76	49.79	45.38	36.38	18.36	18.24	15.00

Source: Mott MacDonald

Table G.14: Refer Figure 7.11: Scenario 2 – Installed capacity mix and peak load [MW]

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
D10	12.50	12.50	12.50	12.50	12.50	-	-	-	-	-
D11	12.50	12.50	12.50	12.50	-	-	-	-	-	-
D12	12.50	12.50	12.50	12.50	-	-	-	-	-	-
D13	12.50	12.50	-	-	-	-	-	-	-	-
D14	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70
D15	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70
D2020	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	-
GT02	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
GT03	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
GT04	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
GT05	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
GT06	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
S1	20.00	-	-	-	-	-	-	-	-	-
S2	20.00	-	-	-	-	-	-	-	-	-
WH01	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
WH02	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
RE-Riders Solar	41.80	56.47	68.07	77.60	84.10	89.55	93.98	96.37	98.76	100.13
Trents PV01	9.95	9.89	9.83	9.77	9.71	9.65	9.59	9.53	9.47	9.41
MSD Resiliency Bridge	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04
On-shore Wind	-	6.81	26.81	46.81	66.81	86.81	106.81	126.81	146.81	166.81
Solar CSP2 - 15h TES	-	-	-	-	-	-	-	-	-	20.00
Solar CSP3 - 12h TES	-	-	-	-	-	20.00	20.00	20.00	20.00	20.00
Solar CSP3 - 15h TES	-	-	-	-	20.00	20.00	20.00	20.00	20.00	20.00

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar Utility-Scale 1.5	-	19.93	39.79	59.56	79.26	98.87	118.41	117.92	117.44	116.97
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	19.97	39.89	59.78
Battery 3H	-	-	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Battery 4H	-	42.61	92.61	94.99	94.99	95.16	95.16	96.19	125.33	153.89
Trents Storage 1 (2018)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	-	-
Peak Load (MW)	159.24	160.37	161.82	163.35	164.96	164.85	164.77	164.70	164.65	165.26
Capacity Reserve Margin (%)	66.73	53.89	65.72	62.10	51.08	46.65	37.56	23.97	23.95	20.35

Source: Mott MacDonald

Table G.15: Refer Figure 7.12: Scenario 3 – Installed capacity mix and peak load [MW]

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
D10	12.50	12.50	12.50	12.50	12.50	-	-	-	-	-
D11	12.50	12.50	12.50	12.50	-	-	-	-	-	-
D12	12.50	12.50	12.50	12.50	-	-	-	-	-	-
D13	12.50	12.50	-	-	-	-	-	-	-	-
D14	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70
D15	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	29.70	-
D2020	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	-
GT02	13.00	-	-	-	-	-	-	-	-	-
GT03	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
GT04	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
GT05	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
GT06	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
S1	20.00	-	-	-	-	-	-	-	-	-
S2	20.00	-	-	-	-	-	-	-	-	-
WH01	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
WH02	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
RE-Riders Solar	41.80	56.47	68.07	77.60	84.10	89.55	93.98	96.37	98.76	100.13
Trents PV01	9.95	9.89	9.83	9.77	9.71	9.65	9.59	9.53	9.47	9.41
MSD Resiliency Bridge	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04	34.04
Biomass	-	-	-	-	10.00	10.00	10.00	10.00	10.00	10.00
Landfill Gas	-	-	-	-	5.00	5.00	5.00	5.00	5.00	5.00
On-shore Wind	-	6.35	26.35	46.35	66.35	86.35	106.35	126.35	146.35	166.35
Solar CSP1 - 15h TES	-	-	-	-	20.00	20.00	20.00	20.00	20.00	20.00
Solar CSP2 - 12h TES	-	-	-	-	-	20.00	20.00	20.00	20.00	20.00
Solar CSP2 - 15h TES	-	-	-	-	-	-	-	-	-	20.00
Solar Utility-Scale 1.5	-	19.93	39.79	59.56	79.26	98.87	118.41	117.92	117.44	116.97
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	19.97	39.89	59.78
Waste to Energy	-	-	-	-	8.00	8.00	8.00	8.00	8.00	8.00
Battery 3H	-	-	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Battery 4H	-	42.68	92.68	94.39	94.39	94.39	94.39	95.10	124.36	153.37
Trents Storage 1 (2018)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	-	-
Peak Load (MW)	159.24	160.37	161.82	163.35	164.96	164.85	164.77	164.70	164.65	165.26
Capacity Reserve Margin (%)	66.73	47.30	59.53	55.90	57.27	52.58	43.10	28.85	28.63	15.03

Source: Mott MacDonald

Table G.16: Refer Figure 7.13: Scenario 1 – Total costs [Costs (million BBD), LCOE (BBD/MWh)]

Year	Fuel Cost	Start and Shutdown Cost	Emissions Cost	VO&M Cost	FO&M Cost	Annualized Build Cost	LCOE Cost
2021	138.37	4.18	121.18	42.15	20.40	7.64	336.64
2022	117.37	0.04	96.03	50.14	22.30	24.05	302.37
2023	116.12	0.03	85.94	54.47	34.53	58.41	328.24
2024	115.68	0.04	76.34	57.80	37.89	69.44	330.92
2025	111.60	0.04	68.65	59.70	39.70	78.46	318.71
2026	95.54	0.04	58.55	60.95	42.70	86.59	298.83
2027	87.80	0.04	50.80	62.11	45.70	94.03	281.42
2028	89.05	0.03	50.56	63.33	47.83	101.21	270.54
2029	51.05	0.07	29.20	63.39	58.99	135.21	248.52
2030	29.79	0.10	17.87	63.46	72.55	168.98	247.65

Source: Mott MacDonald

Table G.17: Refer Figure 7.14: Scenario 2 – Total costs [Costs (million BBD), LCOE (BBD/MWh)]

Year	Fuel Cost	Start and Shutdown Cost	Emissions Cost	VO&M Cost	FO&M Cost	Annualized Build Cost	LCOE Cost
2021	138.41	4.18	121.15	42.16	20.40	7.64	336.66
2022	114.55	0.04	93.87	49.95	22.86	26.08	299.64
2023	112.66	0.03	83.57	54.08	35.09	60.74	326.24
2024	112.13	0.04	74.05	57.46	38.49	71.76	328.50
2025	82.88	0.05	51.06	59.30	46.42	105.46	309.45
2026	46.38	0.07	28.50	60.89	55.55	136.31	280.08
2027	38.47	0.08	22.30	62.32	58.54	143.74	264.32
2028	39.41	0.08	22.58	63.55	62.06	151.21	256.76
2029	31.16	0.09	17.87	63.90	67.27	163.25	251.02
2030	16.25	0.11	9.86	64.05	80.45	198.54	259.16

Source: Mott MacDonald

Table G.18: Refer Figure 7.15: Scenario 3 – Total costs [Costs (million BBD), LCOE (BBD/MWh)]

Year	Fuel Cost	Start and Shutdown Cost	Emissions Cost	VO&M Cost	FO&M Cost	Annualized Build Cost	LCOE Cost
2021	138.41	4.18	121.15	42.16	20.40	7.64	336.67
2022	114.75	0.04	94.01	49.98	22.38	25.96	299.45
2023	112.99	0.03	83.75	54.12	34.62	60.62	326.16
2024	112.50	0.04	74.20	57.49	37.94	71.47	328.35
2025	57.80	0.30	35.61	60.78	56.01	129.67	302.82
2026	27.90	0.30	17.02	62.36	65.13	160.49	282.46
2027	23.34	0.29	13.68	63.55	68.12	167.92	272.08
2028	24.02	0.32	14.21	64.79	71.63	175.34	264.87
2029	18.90	0.33	11.30	65.00	76.83	187.39	262.18

Year	Fuel Cost	Start and Shutdown Cost	Emissions Cost	VO&M Cost	FO&M Cost	Annualized Build Cost	LCOE Cost
2030	12.16	0.35	7.73	64.90	88.25	222.75	278.75

Source: Mott MacDonald

Table G.19: Refer Figure 7.16: Scenario 1 – Generation mix [GWh]

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
D10	50.41	59.22	48.82	39.59	34.28	23.29	19.60	13.29	-	-
D11	26.91	37.36	32.40	22.48	-	-	-	-	-	-
D12	26.38	34.87	33.29	27.10	27.40	19.73	16.04	-	-	-
D13	33.50	42.90	-	-	-	-	-	-	-	-
D14	196.13	203.90	201.10	187.08	170.12	145.61	121.52	123.18	74.52	45.89
D15	172.31	172.76	171.48	170.39	167.63	153.20	139.71	137.70	91.78	60.33
D2020	4.91	7.29	3.78	1.66	1.95	1.90	1.20	3.37	0.79	-
GT02	-	-	-	-	-	-	-	-	-	0.29
GT03	0.95	0.09	0.20	0.04	0.09	0.06	0.03	0.17	-	0.29
GT04	0.88	0.73	0.31	0.22	0.59	0.47	-	0.64	-	1.10
GT05	1.98	3.07	1.06	0.57	0.59	0.53	0.38	1.22	0.24	0.67
GT06	0.17	0.41	0.07	-	-	0.05	0.05	-	-	0.54
S1	99.32	-	-	-	-	-	-	-	-	-
S2	71.72	-	-	-	-	-	-	-	-	-
WH01	5.92	5.58	5.21	4.81	3.55	2.62	2.03	-	-	-
WH02	10.25	10.22	10.25	10.33	10.24	9.30	8.67	8.40	5.59	3.59
RE-Riders Solar	62.50	85.40	102.95	117.66	127.16	135.40	142.11	146.16	149.39	150.60
Trents PV01	16.71	17.51	17.99	17.92	17.77	17.66	17.56	17.48	17.33	17.13
MSD Resiliency Bridge	205.36	266.61	238.83	188.16	158.91	124.04	100.00	109.00	53.56	22.34
On-shore Wind	-	4.85	58.44	111.92	166.63	220.00	273.08	327.87	379.28	430.08
Solar CSP1 - 12h TES	-	-	-	-	-	-	-	-	-	76.82
Solar CSP2 - 12h TES	-	-	-	-	-	-	-	-	95.64	76.27
Solar Utility-Scale 1.3	-	44.34	45.31	43.96	43.33	44.47	44.43	43.01	43.36	41.63

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar Utility-Scale 1.5	-	-	50.66	98.95	146.72	201.63	251.01	288.11	288.95	279.64
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	4.27	52.60	95.71
Battery 3H	-	-	8.82	7.69	9.57	14.22	20.12	21.68	27.69	26.04
Battery 4H	-	24.81	31.39	26.79	34.96	35.88	49.28	52.63	78.94	95.45
Trents Storage 1 (2018)	5.60	3.10	2.45	2.08	2.25	2.44	3.01	2.98	-	-
Native Load (GWh)	946.99	953.00	962.00	971.00	981.00	980.00	979.00	979.00	979.00	976.94
Purchaser Load (GWh)	38.31	39.29	52.75	65.97	88.04	110.77	146.38	231.57	256.46	305.25

Source: Mott MacDonald

Table G.20: Refer Figure 7.17: Scenario 2 – Generation mix [GWh]

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
D10	50.52	57.60	46.43	37.37	8.82	-	-	-	-	-
D11	25.95	34.52	29.39	20.33	-	-	-	-	-	-
D12	24.77	31.03	32.85	25.97	-	-	-	-	-	-
D13	35.49	41.18	-	-	-	-	-	-	-	-
D14	195.71	203.92	199.29	181.71	146.01	77.20	53.78	54.39	38.10	20.79
D15	172.23	171.98	170.70	170.34	157.59	117.25	88.80	89.19	67.98	41.33
D2020	5.11	6.51	3.05	1.26	1.04	0.62	0.30	0.39	0.16	-
GT02	0.02	-	-	-	-	-	-	-	-	-
GT03	0.69	0.12	-	-	0.06	-	-	-	0.03	0.03
GT04	1.00	0.85	0.04	0.49	0.14	-	-	-	-	-
GT05	2.33	2.76	0.70	0.28	0.31	0.14	-	-	0.03	0.53
GT06	0.33	0.05	-	-	-	-	-	-	-	0.04
S1	99.34	-	-	-	-	-	-	-	-	-

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
S2	71.45	-	-	-	-	-	-	-	-	-
WH01	5.95	5.70	5.12	4.56	-	-	-	-	-	-
WH02	10.25	10.14	10.36	10.35	9.61	7.35	5.89	5.89	4.92	2.60
RE-Riders Solar	62.50	85.39	102.95	117.66	127.17	135.40	142.10	146.14	149.38	150.38
Trents PV01	16.71	17.95	17.99	17.92	17.77	17.66	17.50	17.42	17.27	17.02
MSD Resiliency Bridge	205.92	261.81	229.51	180.64	107.82	36.15	33.90	31.17	28.82	10.19
On-shore Wind	-	18.35	71.94	125.41	180.21	233.55	286.58	341.42	392.72	443.51
Solar CSP2 - 15h TES	-	-	-	-	-	-	-	-	-	68.94
Solar CSP3 - 12h TES	-	-	-	-	-	103.09	96.26	91.65	85.03	74.03
Solar CSP3 - 15h TES	-	-	-	-	120.86	118.87	118.97	116.99	113.06	100.83
Solar Utility-Scale 1.5	-	47.10	101.13	148.10	195.17	249.74	291.15	283.96	279.94	267.32
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	43.59	75.02	104.20
Battery 3H	-	-	8.48	6.55	11.37	22.74	30.46	30.60	29.18	29.17
Battery 4H	-	25.43	28.96	26.43	29.08	47.02	61.81	63.26	86.90	93.94
Trents Storage 1 (2018)	5.64	3.37	2.25	2.06	2.33	3.24	3.79	3.84	-	-
Native Load (GWh)	946.99	952.99	962.00	971.00	981.00	980.00	979.00	979.00	979.00	976.94
Purchaser Load (GWh)	38.26	39.02	52.60	65.73	84.38	104.68	140.07	226.32	254.24	303.68

Source: Mott MacDonald

Table G.21: Refer Figure 7.18: Scenario 3 – Generation mix [GWh]

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
D10	50.62	57.82	46.62	37.91	1.81	-	-	-	-	-
D11	25.90	34.67	29.59	20.24	-	-	-	-	-	-
D12	24.72	31.43	32.87	25.81	-	-	-	-	-	-
D13	35.49	41.06	-	-	-	-	-	-	-	-
D14	195.82	203.95	199.54	181.59	85.55	26.13	19.51	24.45	11.45	14.66
D15	172.23	172.00	170.78	170.12	126.54	62.69	42.42	38.02	30.72	-
D2020	5.10	6.48	3.12	1.74	0.22	0.04	0.02	0.01	-	-
GT02	0.02	-	-	-	-	-	-	-	-	-
GT03	0.72	0.33	-	-	-	-	0.03	-	-	0.29
GT04	0.95	0.86	0.39	0.54	-	-	-	-	-	-
GT05	2.45	2.75	0.79	0.48	-	-	-	-	-	0.68
GT06	0.25	0.04	-	-	-	-	-	-	-	-
S1	99.34	-	-	-	-	-	-	-	-	-
S2	71.44	-	-	-	-	-	-	-	-	-
WH01	5.95	5.72	5.11	4.62	-	-	-	-	-	-
WH02	10.25	10.13	10.30	10.36	8.01	3.53	2.83	2.27	1.83	0.55
RE-Riders Solar	62.50	85.39	102.95	117.66	127.17	135.40	142.11	146.15	149.38	150.32
Trents PV01	16.71	17.98	17.99	17.92	17.77	17.66	17.52	17.42	17.32	17.02
MSD Resiliency Bridge	205.81	262.03	229.62	181.15	33.89	8.89	9.68	10.43	7.85	9.20
Biomass	-	-	-	-	74.03	63.95	57.08	54.98	52.61	41.44
Landfill Gas	-	-	-	-	41.97	32.81	27.34	26.19	23.11	15.61
On-shore Wind	-	17.07	70.65	124.13	178.92	232.26	285.30	340.13	391.45	442.24
Solar CSP1 - 15h TES	-	-	-	-	121.38	113.61	102.70	98.28	85.26	63.63
Solar CSP2 - 12h TES	-	-	-	-	-	100.02	93.22	90.92	84.06	64.55

Name/property	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Solar CSP2 - 15h TES	-	-	-	-	-	-	-	-	-	72.18
Solar Utility-Scale 1.5	-	47.25	101.14	148.10	195.17	249.77	291.21	283.90	280.51	268.45
Solar Utility-Scale 1.7	-	-	-	-	-	-	-	43.59	74.66	104.09
Waste to Energy	-	-	-	-	57.78	47.93	42.45	43.00	40.51	34.78
Battery 3H	-	-	7.42	6.63	15.08	29.66	34.66	32.41	31.64	29.59
Battery 4H	-	25.34	29.97	26.05	35.34	51.70	66.13	66.41	89.70	91.88
Trents Storage 1 (2018)	5.60	3.33	2.38	1.96	2.73	3.60	4.04	3.97	-	-
Native Load (GWh)	946.99	952.99	962.00	971.00	981.00	980.00	979.00	979.00	979.00	976.94
Purchaser Load (GWh)	38.26	39.03	52.62	65.72	80.26	100.33	136.75	222.97	251.60	301.71

Source: Mott MacDonald

Table G.22: Refer Figure 7.23: Scenario 1 – Annual capacity factors [%]

Year	Diesel	HFO	Jet	Solar	Solar Thermal	Wind
2021	3.74	54.79	0.53	17.44	-	
2022	5.55	64.66	0.57	19.45	-	31.19
2023	2.88	62.86	0.22	21.02	-	30.64
2024	1.26	54.96	0.11	21.56	-	30.50
2025	1.48	53.47	0.17	22.08	-	30.79
2026	1.44	44.65	0.15	22.99	-	30.71
2027	0.91	38.09	0.06	23.39	-	30.63
2028	2.56	40.66	0.27	23.30	-	30.65
2029	0.60	26.49	0.03	23.71	54.59	30.54
2030	-	15.62	0.39	23.45	43.93	30.52

Source: Mott MacDonald

Table G.23: Refer Figure 7.24: Scenario 2 – Annual capacity factors [%]

Year	Diesel	HFO	Jet	Solar	Solar Thermal	Wind
2021	3.89	54.75	0.58	17.44	-	-
2022	4.95	63.45	0.50	19.87	-	30.77
2023	2.32	61.35	0.10	21.51	-	30.63
2024	0.96	53.38	0.10	21.94	-	30.50
2025	0.79	44.76	0.07	22.40	68.98	30.79
2026	0.47	27.96	0.02	23.18	63.35	30.71
2027	0.23	21.43	-	23.15	61.43	30.63
2028	0.30	21.17	-	22.90	59.38	30.65
2029	0.12	16.43	0.01	22.39	56.53	30.54
2030	-	8.85	0.08	21.58	46.64	30.52

Source: Mott MacDonald

Table G.24: Refer Figure 7.25: Scenario 3 – Annual capacity factors [%]

Year	BioFuel	Diesel	HFO	Jet	Solar	Solar Thermal	Waste	Wind
2021	-	3.88	54.75	0.58	17.44	-	-	-
2022	-	4.93	63.53	0.62	19.89	-	-	30.69
2023	-	2.38	61.42	0.18	21.51	-	-	30.61
2024	-	1.32	53.42	0.16	21.94	-	-	30.49
2025	88.28	0.17	26.63	-	22.40	69.28	82.44	30.78
2026	73.63	0.03	11.90	-	23.18	60.97	68.39	30.71
2027	64.24	0.02	8.75	0.00	23.15	55.91	60.58	30.62
2028	61.61	0.01	8.81	-	22.90	53.85	61.19	30.65
2029	57.63	-	6.09	-	22.40	48.32	57.81	30.53
2030	43.66	-	4.16	0.15	21.62	38.33	49.90	30.52

Source: Mott MacDonald

Table G.25: Refer Figure 7.32: All scenarios - NPV comparison [Billion BBD]

Scenario	Case	Sensitivity	NPV	NPV Carbon Emissions costs
1	High	CO2	12.87	1.08
1	High	Capex	13.35	0.59
1	High	Fuel	14.12	0.51
1	High	Load	16.55	0.59
1	High	WACC	14.19	0.71
1	Base	Base	12.87	0.62
1	Low	CO2	12.87	0.54
1	Low	Capex	12.14	0.55
1	Low	Fuel	10.77	0.76
1	Low	Load	11.15	0.70
1	Low	WACC	11.98	0.57
2	High	CO2	14.43	-
2	High	Capex	14.82	-
2	High	Fuel	14.91	-
2	High	Load	18.22	-
2	High	WACC	16.16	-
2	Base	Base	13.96	-
2	Low	CO2	13.81	-
2	Low	Capex	13.07	-
2	Low	Fuel	13.78	-
2	Low	Load	12.27	-
2	Low	WACC	12.65	-
3	High	CO2	15.96	-
3	High	Capex	16.41	-
3	High	Fuel	16.18	-
3	High	Load	19.38	-
3	High	WACC	17.95	-
3	Base	Base	15.44	-
3	Low	CO2	15.35	-
3	Low	Capex	14.42	-
3	Low	Fuel	14.93	-
3	Low	Load	13.90	-
3	Low	WACC	14.06	-

Source: Mott MacDonald

Table G.26: Refer Figure 7.36: Total carbon emissions [Million tonnes]

Scenario	Case	Sensitivity	Carbon emissions
1	Base	Base	3.74
1	High	Capex	3.57
1	High	Fuel	3.12

Scenario	Case	Sensitivity	Carbon emissions
1	High	Load	3.60
1	High	WACC	4.34
1	Low	Load	4.23
1	Low	Capex	3.34
1	Low	Fuel	4.63
1	Low	WACC	3.48
2	Base	Base	3.04
2	High	CO2	3.04
2	High	Capex	3.13
2	High	Fuel	2.75
2	High	Load	3.09
2	High	WACC	3.44
2	Low	CO2	3.12
2	Low	Capex	3.37
2	Low	Fuel	3.50
2	Low	Load	3.34
2	Low	WACC	2.86
3	Base	Base	2.76
3	High	CO2	2.74
3	High	Capex	3.07
3	High	Fuel	2.55
3	High	Load	2.76
3	High	WACC	3.32
3	Low	CO2	2.91
3	Low	Capex	2.76
3	Low	Fuel	3.46
3	Low	Load	2.99
3	Low	WACC	2.71

Source: Mott MacDonald

TableG.27: Refer Figure 7.37: Scenario 1 sensitivities capacity additions and retirements [MW]

Scenario	Technology	Built	Retired
1	Battery	1,808.34	45.00
1	BioFuel	-	-
1	Diesel	56.00	135.00
1	HFO	439.77	744.40
1	Jet	-	46.00
1	Solar	1,581.15	-
1	Solar Thermal	340.00	-
1	Waste	-	-
1	Wind	1,273.85	-

Source: Mott MacDonald

TableG.28: Refer Figure 7.38: Scenario 2 sensitivities capacity additions and retirements [MW]

Scenario	Technology	Built	Retired
2	Battery	2,314.35	55.00
2	BioFuel	197.56	-
2	Diesel	-	165.00
2	HFO	374.44	1,115.10
2	Jet	-	26.00
2	Solar	1,951.09	-
2	Solar Thermal	660.00	-
2	Waste	-	-
2	Wind	1,697.09	-

Source: Mott MacDonald

TableG.29: Refer Figure 7.39: Scenario 3 sensitivities capacity additions and retirements [MW]

Scenario	Technology	Built	Retired
3	Battery	2,311.87	55.00
3	BioFuel	365.06	-
3	Diesel	-	165.00
3	HFO	374.44	1,296.40
3	Jet	-	170.00
3	Solar	1,961.10	-
3	Solar Thermal	660.00	-
3	Waste	88.00	-
3	Wind	1,682.97	-

Source: Mott MacDonald

H. Transmission Planning

H.1 Assumptions

The main assumptions for the transmission studies are as follows:

- Transmission studies are done for system extremes listed below:

1. System peak;
2. System minimum;

- System peak is considered for the Loadflow studies for 2021, 2025 and 2030;
- System minimum is considered for the stability studies for the same study years;
- All studies are done for normal (N-0) and emergency N-1 conditions;
- To ensure sufficient fault levels and correct protection grading, synchronous plant is not allowed to drop below 80MVA;
- A base ETAP case file with hourly generation dispatch and demand data is used for the transmission planning and stability studies;
- The ETAP file from BLPC includes accurate generator models;
- Transmission voltages are 69kV and 24kV;
- Distribution voltages are 11kV and below;
- Studies are done on the Transmission system only;
- Generation projects and BESS project are geographically dispersed based on the findings of the PLEXOS generation planning studies and the demand forecast loads are disaggregated to the 11kV busses of the transmission substations. Mitigations to any voltage and thermal violations are considered;
- Electric Vehicle (EV) loads are integrated into the 2025 and 2030 study cases based on the EV demand forecast data;
- EV loads are evenly distributed at each 11kV bus of the 18 existing transmission substations in the Barbados network and modelled as static loads at unity power factor (pf);
- Cruise liner load of 4.5MW was modelled as a static load with unity power factor and was fed from Substation 15 in 2025;
- Cruise liner load of 18MW requires supply in 2030;
- Wind plants are modelled as full wind Type 4 inverter models for the master planning and stability studies;
- The 'WECC WT Control System Type 4' for wind turbines is used for stability studies;
- Batteries are modelled as lumped positive or negative loads in the masterplanning studies;
- Batteries are modelled using a generic BESS frequency control model for the stability modelling. For each battery modelled, the generic model was scaled accordingly to reflect the capacities installed at the various variable renewable energy substations modelled in the network;
- Under normal system conditions, voltages should remain between 1.06 p.u. and 0.96 p.u.;
- Under emergency conditions, voltages should remain between 1.10 p.u. and 0.90 p.u.;
- Under normal and emergency system conditions, transformer loadings will not exceed 100% of transformer rating;
- Under normal system conditions, Overhead Line (OHL) and Underground Cable (UGC) ratings will not exceed 100% of their thermal ratings and cable ratings will not exceed 100% of the cable rating under emergency conditions;

- Under emergency conditions, OHL ratings will not exceed 120% of the line thermal rating;

H.2 Methodology

H.2.1 Loadflow and masterplan studies

The following is the methodology for the transmission planning task:

3. Check the current system for over-voltages or thermal overloading on the 2015 ETAP file;
4. Update the ETAP 2015 file to 2021 using loads and generation derived in the previous tasks;
5. Check for N-1 violations (thermal and voltage), e.g., line or transformer overloads or bus under-voltages or over-voltages;
6. Find mitigations for the N-0 and N-1 violations, e.g., another line or another transformer;
7. List the mitigation projects in a table with its associated budget cost estimate;
8. Ramp the loads to 2025, using the data from shown in TableH.1
9. Add new generation increments as per the generation planning task;
10. Re-run the loadflow and check for any thermal and voltage violations and derive mitigations as per items 3 to 5 above;
11. Adjust system configurations and ramp the loads to 2030 using data from the demand forecast and do the same as items 7. to 8. above.

The following contingencies were investigated for the N-1 studies as they were considered the most onerous because of the quantum of line/cable/transformer power transfer.

TableH.1:Contingencies investigated for N-1 studies

Transmission Line/Transformer Trip	Type	Voltage Level (kV)
SP -CE	Cable	69
SP-WA	Cable	24.9
SP -ST	Cable	24.9
SPT10	50MVA transformer	69/24.9
NO-CA	Cable	24.9
TR- ST 2	Cable	24.9
STT1	20/20/6.667MVA transformer	24.9/11/11
CE7T2	50MVA transformer	69/24.9
CA- ST	Cable	24.9
CE-WA	OHL	24.9
CE-OL	OHL	24.9
HA-OL (breaker open)	OHL	24.9
HA-SW	OHL	24.9
GA-BE	OHL	24.9
GA-RP	Cable	24.9
MS-BE	Cable	24.9
MS-TY	Cable	24.9

Source: Mott MacDonald

H.2.2 Loss analysis

System losses are recorded and compared for the scenarios before and after the integration of the various power plants and transmission infrastructure. It is possible that the addition of generating power plants in remote areas will reduce system losses through providing power to the local area and de-loading the local network, however this will be confirmed via the system studies.

H.2.3 Fault studies

The objective of the fault studies is to determine the maximum three- phase system fault levels. In cases where fault levels are found to exceed the fault rupturing capacities of existing circuit breakers or equipment, these exceedances will be recorded and highlighted, and possible mitigations will be suggested.

The solutions may include:

- Replacement of equipment with devices which have a higher rating;
- Current limiting reactors;
- Splitting busses into smaller sections; and
- Modifying network topology.

The three-phase faults will be studied using the IEC 60909 standard.

H.2.4 Stability studies

Typically, a system is most vulnerable from a frequency stability point of view at system minimum load. The reasons for this are as follows:

- Less system inertia;
- Less system damping;
- Lower actual reserves in MWs even though the reserve percentage may be unchanged; and
- Lower levels of synchronous generation with the associated lower system inertia.

For this reason, we will undertake frequency stability studies at 5am in the morning which was considered as the system minimum load condition for the different years studied. Transient stability studies are also conducted at system minimum. Stability studies are conducted for the years: 2021, 2025 and 2030.

Frequency studies were conducted on the Barbados network for loss of the largest generating unit. Transient stability studies were conducted for a fault on the Trents to Substation 13 line and the line tripped. Stability studies were carried out for the minimum loading condition as it is the most onerous. The most onerous generator trips identified are presented in TableH.2 below.

TableH.2:Generatorunittripsforfrequencystabilitystudies

Study Year	Minimum Load	
	Generator tripped	**Generator rating (MW)**
2021	D15	2021
2025	MSD Resiliency Bridge	2025
2030	Solar CSP1 - 15h TES	2030

Source: Mott MacDonald

The impact of the loss of a large share of large VRE was not investigated as the synchronous generator loss provide the worst-case results. Synchronous generator loss implies loss of system inertia in addition to the machine's real and reactive power support. Intermittency impacts are longer-term impacts (in the order of minutes) and are catered for in the PLEXOS reserve and ramping analysis.

The events considered for frequency and transient stability studies are described below:

Frequency Event:

- Trip the largest generator at t = 5 seconds

Transient Events:

- Apply a 120 ms, three (3) phase bolted fault at the Substation 20 to Substation 13 line at t = 5.0 seconds
- Clear the fault at t = 5.12 seconds
- Trip the Substation 20 to Substation 13 line at t = 5.12 seconds

H.3 Installed Generation

H.3.1 Synchronous generation

The synchronous generation dispatch used for the 2021, 2025, and 2030 modelled scenarios investigated is shown in Table H.3.

Table H.3: Synchronous generation dispatch for investigated study years

Generator	Substation	Rated Capacity (MW)	Power Factor	Dispatched generation (MW)					
				2021		2025		2030	
				Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
S1	Substation 12	17.00	0.85	17.00	-	-	-	-	-
S2	Substation 12	17.00	0.85	0.00	12.19	-	-	-	-
D10	Substation 12	11.00	0.85	7.00	11.00	-	-	-	-
D11	Substation 12	11.00	0.85	-	11.00	-	-	-	-
D12	Substation 12	11.00	0.85	-	11.00	-	-	-	-
D13	Substation 12	11.50	0.85	7.00	9.75	-	-	-	-
D14	Substation 12	27.00	0.85	22.95	27.00	-	-	-	-
D15	Substation 12	27.00	0.85	22.35	27.00	-	22.35	-	-
GT02	Substation 6	11.00	0.80	-	-	-	-	-	-
GT03	Substation 14	11.00	0.80	-	-	-	-	-	-
GT04	Substation 14	18.00	0.80	-	-	-	-	-	-
GT05	Substation 14	18.00	0.80	-	-	-	-	-	-
GT06	Substation 14	18.00	0.80	-	-	-	-	-	-
CG01	Substation 12	1.50	0.85	1.50	-	-	-	-	-
CG02	Substation 12	2.20	0.87	2.20	2.20	-	2.20	-	-
WASTE TO ENERGY	Substation 20	8.00	0.85	-	-	8.00	8.00	4.00	4.00
LANDFILL GAS	Substation 20	5.00	0.85	-	-	5.00	5.00	0.80	1.00
MSD Resiliency Bridge	Substation 20	34.04	0.85	-	34.04	17.02	-	-	-
BIOMASS	Substation 20	10.00	0.85	-	-	10.00	-	4.00	4.00
Solar CSP1 - 15h TES	Substation 14	20.00	0.85	-	-	-	20.00	8.79	16.59
Solar CSP2 - 12h TES	Substation 14	20.00	0.85	-	-	-	-	-	2.00
Solar CSP2 - 15h TES	Substation 14	20.00	0.85	-	-	-	-	-	-

Source: Mott MacDonald

H.3.2 VRE Generation

The VRE generation installed in the BLPC network comprised of Solar PV and Wind generation. Table H.4 below shows the Solar PV generation allocation in the BLPC network including existing substation connection points for the 2021, 2025, and 2030 study years.

Table H.4: Generated and Installed Solar PV for 2021, 2025, and 2030

Existing Substation	Voltage Level (kV)	Generated Solar PV (MW)						Installed Solar PV (MW)		
		2021		2025		2030		2021	2025	2030
		Maximum	Minimum	Maximum	Minimum	Maximum	Minimum			
Substation 7	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 17	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 17	11	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 7	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 11	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 10	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 4	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 2	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 16	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 16	11	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 13	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 3	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 9	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 9	11	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 20	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 14	24.9	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 14	11	0.41	0.00	6.80	0.03	13.77	0.07	2.46	9.61	16.29
Substation 20 PV01	24.9	7.26	0.00	6.89	0.00	6.68	0.00	10.00	10.00	10.00
Total Solar PV excl. Substation 20 PV01		**7.05**	**0.00**	**115.54**	**0.47**	**234.11**	**1.16**	**41.80**	**163.35**	**276.88**
Total Solar PV incl. Substation 20 PV01		**14.32**	**0.00**	**122.43**	**0.47**	**240.79**	**1.16**	**51.80**	**173.35**	**286.88**

Source: Mott MacDonald

H.3.3 Wind Generation

Wind generation allocation in the BLPC network including existing substation connection points for the 2021, 2025, and 2030 study years is shown in Table H.5 below. The assumed substation locations were selected based on their proximity to proposed wind farms as indicated in the Google Earth imagery. It should be noted that wind generation only comes online from 2022 and hence there is no installed wind in 2021.

Table H.5: Generated and Installed Wind for 2021, 2025, and 2030

Existing Substation	Busbar voltage level (kV)	Generated Onshore Wind (MW)				Installed Onshore Wind (MW)		
		2025		2030		2021	2025	2030
		Maximum	Minimum	Maximum	Minimum			
Substation 10	24.9	2.7	6.5	8.4	14.1	-	13.3	33.3
Substation 7	24.9	2.7	6.5	8.4	14.1	-	13.3	33.3
Substation 20-St Lucy	24.9	2.7	6.5	8.4	14.1	-	13.3	33.3
Substation 9	24.9	2.7	6.5	8.4	14.1	-	13.3	33.3
Substation 3	24.9	2.7	6.5	8.4	14.1	-	13.3	33.3
Total onshore wind		**13.5**	**32.3**	**41.8**	**70.4**	**-**	**66.3**	**166.3**

Source: Mott MacDonald

H.3.4 Battery Energy Storage Systems (BESS)

Table H.6 below shows the BESS allocation in the BLPC network including existing substation connection points for the 2021, 2025, and 2030 study years. The batteries, except for the existing Substation 20 2018 Battery were evenly distributed across all substations connected to VRE generation.

Table H.6: BESS connection points for 2021, 2025, and 2030

Substation name	Voltage Level (kV)	Battery Capacity (MW)		
		2021	**2025**	**2030**
Substation 9	11	-	9.0	12.7
Substation 9	24.9	-	9.0	12.7
Substation 20	24.9	-	9.0	12.7
Substation 20 (2018 Battery)	24.9	5.0	5.0	-
Substation 3	24.9	-	9.0	12.7
Substation 13	24.9	-	9.0	12.7
Substation 16	11	-	9.0	12.7
Substation 16	24.9	-	9.0	12.7
Substation 2	24.9	-	9.0	12.7
Substation 4	24.9	-	9.0	12.7
Substation 10	24.9	-	9.0	12.7
Substation 11	24.9	-	9.0	12.7
Substation 7	24.9	-	9.0	12.7
Substation 17	11	-	9.0	12.7
Substation 17	24.9	-	9.0	12.7
Substation 14	11	-	9.0	12.7
Substation 14	24.9	-	9.0	12.7
Total Installed Battery Storage		**5.00**	**149.39**	**203.37**

Source: Mott MacDonald

H.4 Fault study results

Table H.7: Fault levels for 2021, 2025, and 2030 with and without SCOs

Bus Name	Voltage (kV)	Fault Levels (kA)				
		2021 Maximum	2025 Maximum	2025 Maximum SCOs	2030 Maximum	2030 Maximum SCOs
SP6-11a	11	33.7	19.9	22.7	17.8	22.8
SP6-11b	11	33.7	19.9	22.7	17.8	22.8
SP3-11a	11	32.7	22.3	23.4	16.8	23.4
SP3-11b	11	32.7	22.3	23.4	16.8	23.4
SP4-24a	24.9	19.8	13.0	14.2	11.3	14.7
SP4-24b	24.9	19.8	13.0	14.2	11.3	14.7
TR11-a	11	19.1	14.0	14.2	16.5	17.0
TR11-b	11	19.1	14.0	14.2	16.5	17.0
Substation 5 - 24	24.9	17.9	12.3	13.2	10.8	13.7
BE1-24a	24.9	16.3	12.3	13.1	11.3	13.6
BE1-24b	24.9	16.3	12.3	13.1	11.3	13.6
BE1-24c	24.9	16.3	12.3	13.1	11.3	13.6
BE-WL J1	24.9	16.3	12.3	13.1	11.3	13.6
CE1-24a	24.9	16.0	12.6	13.3	11.9	14.1
CE1-24b	24.9	16.0	12.6	13.3	11.9	14.1
ST-CE J2	24.9	16.0	12.6	13.3	11.9	14.1
TY1-24	24.9	15.9	11.8	12.6	10.7	13.0
WP1-24	24.9	15.7	11.8	12.5	10.7	13.0
MS-J1	24.9	14.7	11.3	11.9	10.3	12.3
MS-J2	24.9	14.7	11.3	11.9	10.3	12.3
MS1-24	24.9	14.7	11.3	11.9	10.3	12.3
ST2-11	11	13.8	12.6	12.8	12.8	13.4
RP1-24	24.9	12.9	10.7	11.2	10.3	11.8
WA-24	24.9	12.7	9.9	10.4	9.0	10.7
WA-J1	24.9	12.7	9.9	10.4	9.0	10.7
WA1-24	24.9	12.7	9.9	10.4	9.0	10.7
GA1-24	24.9	11.5	9.6	10.1	9.2	10.5
SP2-11	11	10.9	9.9	10.1	13.2	14.8
ST-CA-J	24.9	10.7	9.0	9.2	9.2	10.0
ST-J1	24.9	10.7	9.0	9.2	9.2	10.0
ST-J2	24.9	10.7	9.0	9.2	9.2	10.0
ST1-24	24.9	10.7	9.0	9.2	9.2	10.0
SW1-24	24.9	10.7	10.1	10.5	10.3	11.5
SW1-24b	24.9	10.7	10.1	10.5	10.3	11.5
WA2-11	11	10.6	9.8	10.0	9.6	10.1
MS2-11	11	10.1	9.4	9.6	9.2	9.7
WP2-11	11	9.1	8.6	8.7	8.4	8.7
TR24	24.9	8.8	7.3	7.4	8.1	8.5
Substation 1	24.9	8.8	7.5	7.8	7.1	8.0

Bus Name	Voltage (kV)	Fault Levels (kA)				
		2021 Maximum	2025 Maximum	2025 Maximum SCOs	2030 Maximum	2030 Maximum SCOs
WO1-24	24.9	8.7	8.1	8.3	8.0	8.8
WO2-11	11	8.6	8.4	8.5	8.4	8.6
CA1-24	24.9	8.5	7.4	7.5	7.5	8.0
RP2-11	11	7.8	7.4	7.5	10.7	11.4
TY2-11a	11	7.7	7.4	7.5	7.3	7.5
TY2-11b	11	7.7	7.4	7.5	7.3	7.5
Substation 5 - 11	11	7.6	7.0	7.2	6.8	7.2
GA2-11a	11	7.6	7.3	7.3	7.2	7.4
GA2-11b	11	7.6	7.3	7.3	7.2	7.4
SW2-11	11	7.2	15.4	15.5	20.5	21.1
OL1-24	24.9	7.0	6.4	6.6	6.3	6.8
OLJ1-24	24.9	7.0	6.4	6.6	6.3	6.8
OLJ2-24	24.9	7.0	6.4	6.6	6.3	6.8
HA1-24	24.9	6.9	6.5	6.6	6.5	7.0
CA2-11	11	6.7	6.5	6.5	9.3	9.6
OL2-11	11	6.4	6.2	6.3	8.5	8.9
NO2-11	11	6.4	6.2	6.2	6.2	6.3
NO1-24	24.9	6.2	5.6	5.7	5.7	5.9
CE2-11	11	6.0	5.8	5.8	5.7	5.9
HA2-11	11	5.9	5.8	5.8	5.8	5.9
BE2-11	11	5.7	5.5	5.5	5.4	5.6
CE-WL J1	24.9	5.6	5.2	5.3	5.1	5.4
Substation 19	24.9	5.6	5.2	5.3	5.1	5.4
SP-J1	69	5.4	3.9	4.1	3.6	4.3
SP-J2	69	5.4	3.9	4.1	3.6	4.3
SP-J3	69	5.4	3.9	4.1	3.6	4.3
SP-J4	69	5.4	3.9	4.1	3.6	4.3
SP-J5	69	5.4	3.9	4.1	3.6	4.3
SP-J6	69	5.4	3.9	4.1	3.6	4.3
SP7-69a	69	5.4	3.9	4.1	3.6	4.3
SP7-69b	69	5.4	3.9	4.1	3.6	4.3
CE-J1	69	5.3	3.9	4.1	3.6	4.3
CE-J2	69	5.3	3.9	4.1	3.6	4.3
CE-J3	69	5.3	3.9	4.1	3.6	4.3
CE-J4	69	5.3	3.9	4.1	3.6	4.3
CE3-69a	69	5.3	3.9	4.1	3.6	4.3
CE3-69b	69	5.3	3.9	4.1	3.6	4.3

Source: Mott MacDonald

H.5 Loss analysis results

Table H.8: System losses for 2021, 2025, and 2030 at branch level

Transformer ID	Maximum (kW)			Minimum (kW)		
	2021	2025	2030	2021	2025	2030
BET1-P	1.4	3.3	13.6	0.3	0.4	1.4
CA-NO	71.0	0.8	54.3	18.1	3.6	1.4
CAT1-P	5.2	8.1	5.4	1.0	1.2	3.8
CAT2-P			4.4			
CE-BE	28.8	63.3	166.0	16.2	36.3	79.6
CE-OL	55.2	10.7	113.5	24.1	7.3	16.9
CE-RP	84.7	23.2	22.4	13.4	24.9	1.5
CE-SP (1)	42.4	11.5	3.2	11.4	5.1	1.8
CE-SP (2)	42.4	11.5	3.2	11.4	5.1	1.8
CE-SW (1)	50.5	92.0	215.3	12.1	2.2	222.6
CE-SW (2)	50.2	91.4	213.8	12.0	2.2	221.0
CE-WA	38.9	3.2	15.5	15.5	14.9	17.9
CE7T 2	32.7	10.9	3.1	9.9	5.7	1.2
CE7T 3	32.7	10.9	3.1	9.9	5.7	1.2
CET1-P	14.9	21.0	40.2	2.7	3.3	10.2
DPT1-P	0.2	0.9	6.4	0.0	0.1	0.3
GA-BE	27.6	2.1	17.2	7.8	2.4	7.6
GA-RP	4.5	60.8	152.8	4.5	12.3	63.5
GAT1-P	12.4	17.1	32.1	2.3	2.7	8.3
HAT1-P	12.1	17.3	34.6	4.5	4.9	9.1
MS-BE	6.8	23.1	50.3	2.7	7.9	22.9
MS-TY	26.0	2.1	4.7	6.8	3.5	0.1
MST1-P	16.9	22.0	36.6	2.8	3.2	10.7
NOT1-P	32.4	14.7	14.8	8.2	8.0	6.8
OHL BE-Load bus 19	45.4	49.4	45.7	7.7	8.2	25.8
OHL CE-Load bus 19	154.8	167.6	137.4	25.8	27.2	86.9
OL-HA	2.5	28.7	70.9	2.6	0.9	21.5
OLT1-P	11.3	30.8	15.4	7.1	2.3	7.6
OLT2-P			13.0			
RPT1-P	19.3	25.5	10.4	3.5	4.0	12.6
RPT3-P			10.4			
SP-BE	158.0	18.5	17.8	38.1	15.3	0.5
SP-DE	27.8	10.9	16.2	6.0	2.9	1.9
SP-ST	87.1	205.1	1206.2	207.0	941.7	129.8
SP-TY	407.0	149.7	148.5	83.4	35.3	28.1
SP-WA	180.4	7.7	51.7	42.5	27.8	12.0
SPT1-P	45.8	56.0	23.3	7.5	8.3	30.8
SPT4-P			17.4			
SPT6				98.0		

Transformer ID	Maximum (kW)			Minimum (kW)		
	2021	2025	2030	2021	2025	2030
SPT7	60.9					
SPT 8	137.3	0.2	16.6	10.4	0.0	0.0
SPT 9	137.3	0.2	16.6	10.4	0.0	0.0
SPT10	68.0	5.9	2.6	24.9	2.1	2.4
SPT11	13.4	4.5	2.0	38.7	1.6	1.9
SPT 15 (92)	100.7	89.0	10.7	56.0	0.0	0.0
SPT15 (92)2	31.6	3.9	6.8	0.0	52.0	9.4
SPTT14 (91)	100.6	88.9	10.7	55.9	0.0	0.0
SPTT14 (91)2	31.6	3.8	6.7	0.0	52.0	9.4
ST - AF Tee	97.5	52.9	237.0	23.8	313.5	12.3
ST - CA	81.0	8.3	116.4	17.9	16.0	3.2
STT 1-P	15.5	21.2	22.0	9.1	15.9	19.9
STT 2-P	8.9	11.6	15.9	8.0	14.0	11.6
SW - HA	14.8	2.0	76.1	6.4	10.7	24.1
SW - WO	1.1	14.9	28.3	0.8	4.5	55.9
SWT 2-P	26.8	14.2	12.1	4.9	5.5	40.9
SWT 3-P		14.2	12.1			40.9
SWT 4-P						40.9
TR-ST-1	554.5	198.4	424.5	9.0	653.6	131.8
TR-ST-2	554.5	198.4	424.5	9.0	653.6	131.8
TYT 1-P	59.7	70.4	94.3	10.3	11.4	36.6
WAT 1-P	25.8	15.7	16.7	4.4	4.7	4.7
WO - RP	14.5	56.0	138.2	7.7	3.1	92.7
WOT2-P	5.5	1.5	2.4	2.1	1.2	1.9
WP - BE	6.6	11.4	33.6	3.1	5.5	16.3
WP - DE	125.3	37.5	32.6	26.8	11.6	5.3
WP - TY	4.0	3.9	6.3	1.7	2.7	4.2
WPT2-P	32.3	41.0	63.4	5.3	6.0	19.8

Source: Mott MacDonald

I. Multi-Criteria Assessment Data

Click the icon below to open the MCA Spreadsheet

Table I.1: Water use for the different technologies

Technology	Water Usage (Litres/MWh)
CSP	3274
Biomass Plant	3625
Biomass (Sugar cane cultivation)	87678
Waste Plant	3625
Landfill Gas Plant	3625

Table I.2: Bio-physical sub-criteria scoring[11]

Technology	Noise Impact	Visual Impact	Air Pollution	Water Pollution	Wildlife Conservation	Waste Accumulation	Land Depletion	Aggregated Bio-Physical Impact
CSP	1	4	1	2	3	4	5	2.9
Wind	5	5	5	1	4	5	5	4.3
Biomass	2	2	2	1	1	2	2	1.7
Waste	2	1	1	3	2	1	1	1.6
Landfill Gas	2	1	1	2	1	1	1	1.3

Table I.3: Climate resilience sub-criteria scoring[12]

Technology	Resilience to High Wind speed (>55mph)	Resilience to Flooding	Resilience to Drought	Aggregated Climate Resilience
CSP	3	3	2	2.7
Wind	1	5	5	3.7
Biomass	4	1	1	2.0
Waste	5	2	2	3.0
Landfill Gas	5	2	2	3.0

[11] Score for each Bio Physical impact ranges from 1 (Least impact) to 5 (Highest Impact). The Lowest value indicates positive or no impact on the Bio-physical criterion

[12] Score for each climate resilience ranges from 1 (least Resilience) to 5 (Highest Resilience).

Table I.4: Job creation for the different technologies

Technology	Type of Job	Job Created (Jobs/MW)
CSP	Construction	5
	Operation	0.5
Wind	Construction	2.5
	Operation	0.7
Biomass	Construction	3
	Operation	0.2
	Indirect jobs from cultivation, processing, and logistics	10
Waste	Construction	155 Jobs/Plant
	Operation	13 Jobs/Plant
Landfill Gas	Construction	155 Jobs/Plant
	Operation	13 Jobs/Plant

Table I.5: Construction ESIA sub-criteria scoring[13]

Technology	Air & Water Pollution	Deforestation	Resettlement	Social Resistance	Aggregated Construction ESIA
CSP	4	4	3	4	3.8
Wind	5	5	5	5	5.0
Biomass	1	3	4	3	2.8
Waste	2	1	1	2	1.5
Landfill Gas	1	1	1	1	1.0

Table I.6: Final MCA results for environmental sensitivity 1 analysis

Criteria		LCP	CO2	FRES
Scenario Cost	Scenario Cost (Billion BB$)	13.51	13.99	15.47
	Normalised Scenario Cost	1.00	0.97	0.87
	Weight	0.10	0.10	0.10
	Scenario cost Final Score	0.10	0.10	0.09
	Ranking	1.00	2.00	3.00
Water Use	Water use (Million Litres)	814.32	3956.88	35590.35
	Normalised Water Use	1.00	0.21	0.02
	Weight	0.20	0.20	0.20
	Water use Final Score	0.20	0.04	0.00
	Ranking	1.00	2.00	3.00
Land Use	Land Use (Acres)	6543.00	7158.00	12182.00
	Normalised Land Use	1.00	0.91	0.54
	Weight	0.20	0.20	0.20
	Land Use Final Score	0.20	0.18	0.11
	Ranking	1.00	2.00	3.00

[13] Score for each impact ranges from 1 (least impact) to 5 (Highest Impact). The Lowest value indicates a positive or no impact on the criterion

Criteria		LCP	CO2	FRES
Bio-physical Impact	Bio-physical impact	6.06	7.14	11.70
	Normalised Bio-Physical Impact	1.00	0.85	0.52
	Weight	0.20	0.20	0.20
	Bio-physical Final Score	0.20	0.17	0.10
	Ranking	1.00	2.00	3.00
Climate Resilience	Climate Resilience	5.33	6.33	14.32
	Normalised Climate Resilience	0.37	0.44	1.00
	Weight	0.20	0.20	0.20
	Climate Resilience Final Score	0.07	0.09	0.20
	Ranking	3.00	2.00	1.00
Job creation	Job Creation	737.76	863.76	1330.48
	Normalised Jobs	0.55	0.65	1.00
	Weight	0.05	0.05	0.05
	Jobs Creation Final score	0.03	0.03	0.05
	Ranking	3.00	2.00	1.00
Construction ESIA Impact	Construction ESIA Impact	7.35	8.75	13.99
	Normalised Construction ESIA	1.00	0.84	0.53
	Weight	0.05	0.05	0.05
	Construction ESIA final score	0.05	0.04	0.03
	Ranking	1.00	2.00	3.00
Total MCA Scores and Ranking	Total Scores	0.85	0.65	0.58
	Final Ranking	1 2	2 3	3 1

Table I.7: Final MCA results for environmental sensitivity 2 analysis

Criteria		LCP	CO2	FRES
Scenario Cost	Scenario Cost (Billion BB$)	13.51	13.99	15.47
	Normalised Scenario Cost	1.00	0.97	0.87
	Weight	0.10	0.10	0.10
	Scenario cost Final Score	0.10	0.10	0.09
	Ranking	1.00	2.00	3.00
Water Use	Water use (Million Litres)	814.32	3956.88	35590.35
	Normalised Water Use	1.00	0.21	0.02
	Weight	0.20	0.20	0.20
	Water use Final Score	0.20	0.04	0.00
	Ranking	1.00	2.00	3.00
Land Use	Land Use (Acres)	6543.00	7158.00	2142.00
	Normalised Land Use	0.33	0.30	1.00

Criteria		LCP	CO2	FRES
	Weight	0.20	0.20	0.20
	Land Use Final Score	0.07	0.06	0.20
	Ranking	2.00	3.00	1.00
Bio-physical Impact	Bio-physical impact	6.06	7.14	11.70
	Normalised Bio-Physical Impact	1.00	0.85	0.52
	Weight	0.20	0.20	0.20
	Bio-physical Final Score	0.20	0.17	0.10
	Ranking	1.00	2.00	3.00
Climate Resilience	Climate Resilience	5.33	6.33	14.32
	Normalised Climate Resilience	0.37	0.44	1.00
	Weight	0.20	0.20	0.20
	Climate Resilience Final Score	0.07	0.09	0.20
	Ranking	3.00	2.00	1.00
Job creation	Job Creation	737.76	863.76	1330.48
	Normalised Jobs	0.55	0.65	1.00
	Weight	0.05	0.05	0.05
	Jobs Creation Final score	0.03	0.03	0.05
	Ranking	3.00	2.00	1.00
Construction ESIA Impact	Construction ESIA Impact	7.35	8.75	13.99
	Normalised Construction ESIA	1.00	0.84	0.53
	Weight	0.05	0.05	0.05
	Construction ESIA final score	0.05	0.04	0.03
	Ranking	1.00	2.00	3.00
Total MCA Scores and Ranking	Total Scores	0.72	0.53	0.67
	Final Ranking	1	3	2

Table I.8: Final MCA results for social sensitivity 1 analysis

Criteria		LCP	CO2	FRES
Scenario Cost	Scenario Cost (Billion BB$)	13.51	13.99	15.47
	Normalised Scenario Cost	1.00	0.97	0.87
	Weight	0.20	0.20	0.20
	Scenario cost Final Score	0.20	0.19	0.17
	Ranking	1.00	2.00	3.00
Water Use	Water use (Million Litres)	814.32	3956.88	35590.35
	Normalised Water Use	1.00	0.21	0.02
	Weight	0.10	0.10	0.10
	Water use Final Score	0.10	0.02	0.00
	Ranking	1.00	2.00	3.00
Land Use	Land Use (Acres)	6543.00	7158.00	12182.00

Criteria		LCP	CO2	FRES
	Normalised Land Use	1.00	0.91	0.54
	Weight	0.10	0.10	0.10
	Land Use Final Score	0.10	0.09	0.05
	Ranking	1.00	2.00	3.00
Bio-physical Impact	Bio-physical impact	6.06	7.14	11.70
	Normalised Bio-Physical Impact	1.00	0.85	0.52
	Weight	0.10	0.10	0.10
	Bio-physical Final Score	0.10	0.08	0.05
	Ranking	1.00	2.00	3.00
Climate Resilience	Climate Resilience	5.33	6.33	14.32
	Normalised Climate Resilience	0.37	0.44	1.00
	Weight	0.15	0.15	0.15
	Climate Resilience Final Score	0.06	0.07	0.15
	Ranking	3.00	2.00	1.00
Job creation	Job Creation	737.76	863.76	1330.48
	Normalised Jobs	0.55	0.65	1.00
	Weight	0.25	0.25	0.25
	Jobs Creation Final score	0.14	0.16	0.25
	Ranking	3.00	2.00	1.00
Construction ESIA Impact	Construction ESIA Impact	7.35	8.75	13.99
	Normalised Construction ESIA	1.00	0.84	0.53
	Weight	0.10	0.10	0.10
	Construction ESIA final score	0.10	0.08	0.05
	Ranking	1.00	2.00	3.00
Total MCA Scores and Ranking	Total Scores	0.79	0.70	0.73
	Final Ranking	1	3	2

Table I.9: Final MCA results for social sensitivity 2 analysis

Criteria		LCP	CO2	FRES
Scenario Cost	Scenario Cost (Billion BB$)	13.51	13.99	15.47
	Normalised Scenario Cost	1.00	0.97	0.87
	Weight	0.20	0.20	0.20
	Scenario cost Final Score	0.20	0.19	0.17
	Ranking	1.00	2.00	3.00
Water Use	Water use (Million Litres)	814.32	3956.88	35590.35
	Normalised Water Use	1.00	0.21	0.02
	Weight	0.10	0.10	0.10
	Water use Final Score	0.10	0.02	0.00
	Ranking	1.00	2.00	3.00

Criteria		LCP	CO2	FRES
Land Use	Land Use (Acres)	6543.00	7158.00	2142.00
	Normalised Land Use	0.33	0.30	1.00
	Weight	0.10	0.10	0.10
	Land Use Final Score	0.03	0.03	0.10
	Ranking	2.00	3.00	1.00
Bio-physical Impact	Bio-physical impact	6.06	7.14	11.70
	Normalised Bio-Physical Impact	1.00	0.85	0.52
	Weight	0.10	0.10	0.10
	Bio-physical Final Score	0.10	0.08	0.05
	Ranking	1.00	2.00	3.00
Climate Resilience	Climate Resilience	5.33	6.33	14.32
	Normalised Climate Resilience	0.37	0.44	1.00
	Weight	0.15	0.15	0.15
	Climate Resilience Final Score	0.06	0.07	0.15
	Ranking	3.00	2.00	1.00
Job creation	Job Creation	737.76	863.76	1330.48
	Normalised Jobs	0.55	0.65	1.00
	Weight	0.25	0.25	0.25
	Jobs Creation Final score	0.14	0.16	0.25
	Ranking	3.00	2.00	1.00
Construction ESIA Impact	Construction ESIA Impact	7.35	8.75	13.99
	Normalised Construction ESIA	1.00	0.84	0.53
	Weight	0.10	0.10	0.10
	Construction ESIA final score	0.10	0.08	0.05
	Ranking	1.00	2.00	3.00
Total MCA Scores and Ranking	Total Scores	0.73	0.64	0.78
	Final Ranking	2	3	1

J. Stakeholder Consultation Feedback

J.1 Stakeholder Sessions

Stakeholder sessions were held on the following days and at the following times:

Figure J.1: Session times for the live stakeholder sessions

Theme Numbers	Date 1	Time Slot 1	Date 2	Time Slot 2
1, 2 and 3	28th July 2020	09h00 to 12h00	30th July 2020	13h30 to 16h00
4, 5 and 6	29th July 2020	09h00 to 12h00	31st July 2020	13h30 to 16h00

Source: Mott MacDonald

Session themes were as follows:

1. Renewable Energy (RE) Options and Constraints on Deployment. Energy Efficiency (EE) and Conservation
2. Energy Demand Patterns, Energy demand patterns, energy efficiency and conservation, end-user substitution and likely growth rates
3. Network requirements, system operation and resilience issues
4. Role of oil and gas (incl. LNG) in future of the energy sector in Barbados
5. Policy drivers, multi-criteria analysis (MCA) for assessing strategies
6. Socio-economic dimensions (thematic area to be further developed)

There additional sessions were held with the department of transport, the department of town planning and the department of agriculture during the week 10th – 14th August based on the same themes.

An invitation letter was sent to stakeholders from the MESBE. A copy of the invitation letter can be found in Appendix B.

J.2 Stakeholder feedback summary

This section provides a summary of the key outcomes from the stakeholder feedback and describes how this feedback will influence the assumptions of the IRRP. The key stakeholder points that should be considered in the IRRP study are as follows:

1. Although there are competing plans such as an LNG development plan, the BNEP 2019-2030 100% renewable vision should be the guiding principle for the IRRP;
2. There appear to be three main competitors for land: 1) agriculture, 2) growing of biomass for energy, and 3) VRE power plants. These three sectors do not need to be mutually exclusive and further studies should be undertaken to find how all three of these land-use endeavours can be accommodated. Failing this analysis, assumptions will need to be made in this IRRP exercise;
3. Only mature technologies should be included in the IRRP;
4. Failing a comprehensive bioenergy study, assumptions will need to be made in the IRRP;
5. Failing a comprehensive electric mobility or alternative-fuel mobility study, assumptions will be made in the study regarding the penetration or uptake of EVs in Barbados;
6. Resilience measures such as conversion of OHLs to UGCs, system sub-islanding and distributed generation should be incorporated into the IRRP;

7. Failing comprehensive longer-term storage studies such as CAES, HPS and hydrogen, assumptions will need to be made in the IRRP;
8. System reliability solutions such as SCOs should be included in the IRRP;
9. Criteria such as jobs, forex, environmental impacts, etc. should be included in the MCA analysis

More detailed feedback from the stakeholder live sessions can be found in the following section.

J.3 Feedback Session 1 – Themes 1 to 3

J.3.1 Carbon pricing

The study will be considering operational carbon only and not embedded carbon. NDC commitments generally omit marine and aviation emissions.

More work is required by the GoB to understand the process of buying and selling carbon certificates. Barbados produces 2 million tonnes of CO_2 per year, at US$10/tonne, this amounts to $20m.

J.3.2 Challenges associated with high penetrations of renewable energy

Land is limited in Barbados, however, use of residential and commercial rooftops has several advantages as follows:

- Enfranchisement of citizens
- Does not take up land required for other uses
- Proximity to load
- “Backyards” can also be used if required

There are approximately 90,000 dwelling rooftops available. At 3 kW per rooftop this translates to 270 MW (before dc and inverter losses).

RE and storage affordability is an issue in Barbados for lower income citizens, but funding solutions are actively being evaluated.

Conflict is already being witnessed between developers and landowners. Twenty-five thousand acres of land is required for biomass. Growing of crops is still possible in wind farms but not so possible in PV farms. Water aquifers are susceptible to pollution. Water zones may change to facilitate the development of RE developments however industrial development will not be allowed on sensitive water zones.

Regulatory and legislative constraints still exist in Barbados, but the GoB is working with institutions such as the IDB to address these challenges.

Citizens will require some re-skilling and skills previously employed in the fossil fuel industry will be available to work in the RE industry. The University of the West Indies will be instrumental in the training of citizens. Training should cover wind, solar PV, biomass, and storage.

J.3.3 Pollution from existing fossil fuels

Pollution from existing fossil fuels be it in electricity production or in transport has not had a marked effect on tourism. Marketing Barbados as a “green-island” as it approaches 2030 could have tourism and business benefits such as with Cost Rica.

J.3.4 Possible and viable marine technologies

A report entitled "Ocean Energy in Barbados" dated March 2020 and funded by IDB has been produced. The report reviewed six ocean technologies as follows:

1. **Fixed offshore wind** – good technical potential and established technology but only suitable locations are within 3 km of shore – FAIR POTENTIAL
2. **Floating offshore wind** - very good potential, maturing technology, 189 MW nearby, maturity in 5 years, 8 GW further away – GOOD POTENTIAL
3. **Sea Water Air Conditioning (SWAC)** – further work needed to assess potential, cooling demand not near best cool deep water SWAC sites, 5 years to maturity – UNKNOWN or LIMITED POTENTIAL
4. **Ocean Thermal Energy Conversion (OTEC)** - good theoretical potential, 5 years to maturity, possibly 160 MW – LIMITED POTENTIAL
5. **Wave Energy** – moderate technical potential, 5 years to maturity – LOW POTENTIAL
6. **Tidal and Ocean Current Energy** – not technically viable near Barbados, 10 years to maturity – NO POTENTIAL

The GoB has a policy of only promoting mature, established, and proven technologies and not novel technologies. It appears that at this stage, floating offshore wind and to a lesser extent fixed offshore wind are the most viable ocean technologies for the 2020 – 2030 period.

The west and south are good areas for the above likely technologies due to good water depth. Synergies between ocean technologies and the O&G industry are possible such as the creation of offshore hydrogen from solar and wind.

J.3.5 Bio-energy options

Dispatchable renewable energy from bioenergy was considered important by the stakeholders.

Ethanol can be produced from sugar cane as a fuel, together with the sugar cane bagasse fuel.

River Tamarind, King Grass, Sargassum (seaweed) and waste were also considered as viable bio-energy options.

Growing biofuels is clearly land-intensive; however, the expectation is that between 25 MW and 30 MW is possible from indigenous bioenergy.

500 acres is required per megawatt (MW) using King Grass, so 20 MW requires 10,000 acres. Barbados makes 4 million gallons of reclaimed water. Growing biofuels close to municipal reclaimed water is an option.

Between 5 MW to 8 MW of electricity generation is considered viable from municipal waste. To achieve the 20-30 MW figure, supplemental agricultural biomass will be required.

In terms of transport, it is expected that biofuels will play a part in the migration to EVs.

There is currently a 3-5 MW liquid waste feasibility study in progress. The FTC is looking at a Feed in Tariff (FIT) in the area of BBc40/kWh > 1MW. BBc52.25/kWh <1MW. Rates will apply for 20 years and will be "grandfathered" i.e., they will not change.

There is also a possibility of using the alcohol and yeast from the Rum industry.

Finally, it is possible that the existing BNOCL network can be used to store and transport hydrogen.

J.3.6 Energy storage options

Clearly Li-Ion battery storage is an option due to the decreasing costs of this technology.

There are two storage proposals on the east of Barbados (PHS?) and MESBE will provide a paper on these projects. These projects could link well with storm water and agricultural water requirements.

J.3.7 Energy demand

Air conditioning (A/C) loads will increase however new variable-speed A/Cs are being proposed with smaller loads and better system stability characteristics (variable speed A/Cs do not absorb large steps of power on re-energisation after low-voltage events).

As mentioned, there is likely to be a natural turn-over of the existing car fleet which will delay the transformation of the sector to EVs. In addition, hybrid EVs may fulfil a transitional role. The cost of EVs is still high for groups of citizens in Barbados which will decrease the uptake up EVs. A study has been commissioned by IDB to look at the trajectory of EV penetration in Barbados. There is also an IRENA roadmap looking at the transition to EVs.

Distributed DSM options such as solar-water heating and heat pumps will have an impact on demand. Similarly, the uptake of distributed solar PV will have an impact on demand.

There are plans to prevent the importation of non-efficient domestic appliances.

Increased water demand may be masked by the improvement of the water reticulation system where new PVC and stainless-steel pipes and devices create less frication and therefore less power requirements.

Barbados experienced a drop in 2010 and 2016 as a result of higher global oil prices so there is a certain level of price elasticity of electricity demand.

Even lighting requirements have increased, lighting demand has actually gone down as a result of more efficient fluorescent and LED lighting.

Lower income groups have not taken up solar water heating and solar PV options so there is potential for load to decrease further in these areas if the correct subsidies and incentives are put in place.

The Carnival Cruise Line company is considering switching fuel types and using electricity while in port.

J.3.8 Demand Side Management (DSM) and Demand Side Response (DSR)

Some analysts have estimated that DSM and Energy Efficiency (EE) measures can reduce electricity demand in Barbados by up to 20%.

J.3.9 Network Operations, Reliability and Resilience

While it is acknowledged that Underground Cables (UGCs) are more resilient to extreme climate events (ECEs) than Overhead Lines (OHLs), the cost of UGCs is normally in the range of eight to ten times more expensive than OHLs. It is likely that the Cost of Unserved Energy (CoUE) will far exceed the costs of the UGCs though – especially during and after ECEs.

BLPC is slowly introducing smart meters and GIS systems which should improve the reliability of the system especially when the penetration levels of EVs increase.

While energy storage improves system reliability, some levels of curtailment are inevitable as it is “expensive to always have enough storage”. Back-up thermal generation running on biofuels is an option to improve back-up energy and can reduce curtailment and the overall supply-side costs.

As the RE market develops in Barbados, a curtailment policy will be needed in Barbados that is fair and transparent i.e., if an IPP is curtailed, they will lose kWh income, so the method of curtailment needs to be well understood and communicated.

It was stated that energy resilience in Barbados should not just be at the national level but should be at the building and customer level. Behind the meter energy solutions, smart-buildings, and smart-charging of EVs can add to system ancillary services. Households should aim to be resilient in their own right. GoB has identified 30,000 households to be resilient to climate and other events.

In previous studies done for BLPC, energy storage was co-located with RE generation sites. Some entrepreneurs will see Behind the Meter (BTM) storage as a business opportunity.

The locational benefits of storage are only one value-add from storage, storage also significantly contributes to operational reserve.

For prosumers, there is a buying and a selling rate of electricity. Purchase of electricity from BLPC is at the fuel clause adjustment and the selling rate is the Feed in Tariff (FIT) rate.

Under 3 kW, modified net metering will apply. Greater than 3 kW, net billing above will apply.

Oil and gas wells that are no longer in operation could be used for compressed air storage (CAES). Studies are ongoing.

Hydro Pumped Storage (HPS) round-trip efficiencies are in the 70% range. Compressed Air Energy Storage (CAES) efficiencies are in the low 50% (non-cryogenic is slightly higher).

Imported hydrogen and offshore hydrogen/RE options should be explored. Hydrogen also has other uses such as transport fuel. Hydrogen electrolyser and fuel-cell costs are currently high. From IEA figures, green hydrogen costs are currently USc40/kWh, this excludes the fuel-cell costs.

Synchronous condensers (SCOs) can be used to support system inertia and fault levels as VRE penetration increases.

Sub-system “sub-islanding” improves system resilience. If parts of the island are damaged, other parts of the island can separate from the rest of the island and continue to operate. When the other parts of the island are repaired, re-synchronisation relays can be used to connect the separate sub-islands. This improves brown-out and black-out scenarios.

J.4 Feedback Session 2 – Themes 4 to 6

J.4.1 Role of oil and gas in Barbados

The BNEP 2019-2030 is clear that Barbados aims to be a “100% renewable energy and carbon neutral island-state by 2030”.

Some stakeholders from the Oil and Gas (O&G) sector saw a role for natural gas beyond 2030 for back-up generation and for extreme climate events.

For LNG to play a role to 2030 or beyond, significant, and land-based gas-train infrastructure would be required and possibly high-cost Floating Storage Regasification Units (FSRUs) solutions could be used.

BLPC's 33 MW Energy Bridge diesel plant would transition from HFO to biofuels in 2030. BLPC will follow developments with LNG and may need to transition their plants from HFO to LNG before 2030.

It was stated that natural gas customers currently supplied by NPC comprise only 2% of the country's emissions. These customers would need to migrate to electricity and indigenous oil and gas resources would be exported. It was mentioned that importing such small quantities of biogas for residential and commercial cooking purposes would be prohibitively expensive due to the small quantities involved.

It was stated that a Just Energy Transition (JET) needs to be considered while the country migrates to 100% VRE. Re-purposing of skills for the VRE, storage and EV industries would be recommended.

It was also stated that the country would continue importing "bunker" oil or HFO for the marine sector. HFO infrastructure which is currently used for electricity generation and the marine industry would be underutilised unless portions of this infrastructure could be re-purposed for the importation and used of biofuels in the electricity generating sector.

It was suggested that a portion of existing thermal power plants not required for biofuels generation should be kept serviceable to run in synchronous condenser (SCO) mode and to provide back-up generation during and after extreme weather events.

The question of the ratio of cars running on biofuels and cars running on batteries (i.e., EVs) was raised and it was proposed that a study should be undertaken to determine the EV trajectory in Barbados. Hybrid vehicles as a transition was also proposed.

It was mentioned that the electricity sector should be able to meet it's 100% VRE target. The transport sector currently comprises 30% of energy requirements and that it may be easier to convert cars to biofuels than to convert cars to EVs.

The concept of biofuels was considered a "game-changer" which allows a cheaper 100% VRE vision while provide sufficient back-up generation.

It was mentioned that in Mott MacDonald's previous study for BLPC, a 30 MW restriction was imposed on indigenous biomass and 5 MW for waste.

J.4.2 Policy drivers and Multi-Criteria Assessment (MCA)

It was stated that the evolution of the electricity industry in Barbados should consider economic enfranchisement of consumers and small businesses.

It was also mentioned that the evolution of RE should stick to the six drivers of the BNEP 2019-2030 and that 16-20% of equity and capacity should go to the water authority (BWA).

It was stated that the Renewable Cooperative should be used as a mechanism for equity and citizen participation.

The energy industry should not just provide employment but also equity. "A minimum of 30% of generation and storage should be owned by citizens." Local entrepreneurs have already participated in utility scale RE projects.

It was stated that the MCA should consider a range of criteria such as financial, economic, environment, technical and social. Rooftop area can be monetised by third parties if citizens cannot afford rooftop PV systems.

It was stated that to encourage enfranchisement, better information, and education on the benefits of PV should be provided.

It was mentioned that Barbados does have certain technical challenges such as types of soil, drop-off of coastal shelf and extreme weather events and these should be considered in any planning.

It was mentioned that the optimisation model is a technical model considering reliability, reserve, and resilience. Policy drivers add restrictions and constraints to the least cost IRRP and impact the reliability.

It was mentioned that developing countries have strong policies in place for local development arising from RE projects. A portion of developer project costs could be allocated to funding a single buyer office and for social upliftment.

It was stated that distributed generating systems together with EV could lead to a more resilient system.

Customers should be encouraged to have local storage as well as local PV generation. In addition, water storage is advisable for extreme weather events. It was acknowledged that this would come at a cost to the customer.

It was suggested that the generation and transmission modelling should be enhanced to incorporate climate resilience.

It was questioned who should decide on system reliability, the customer, or the GoB. Currently, there is a 24hour total system outage per year determined by the GoB.

It was mentioned that vulnerable citizens are not able to meet their energy costs and cannot afford RE or storage systems. In addition, vulnerable citizens are involved in the fuels industry. Loss of jobs could result in the migration to 100% RE.

It was questioned whether it was possible that EVs would be the dominant transport medium by 2030.

The rationale for switching from imported fossil fuels to imported biofuels was questioned, as forex “still goes out the country”.

In terms of the conflict between RE and agriculture, it was mentioned that it is possible to create synergies between RE and agriculture. Pasture and agriculture are still possible with wind turbines and crops may be able to be grown under the PV panels, although this would need to be weighed up against the PV design climate resilience factors.

It was mentioned that there are 90,000 rooftops in Barbados. Full rooftop coverage of PV at 3 kW per rooftop amounts to 270 MW. Mention was made of rooftops being composed of solar PV materials. Subsidies, grants, and incentives would be required for full rooftop coverage. As mentioned previously, third parties could rent roof space and provide rental income to the homeowner.

Solar and wind have been granted certain permissions for installation on water sensitive locations – even in locations where industrial activity is not allowed.

There are psychological issues that need to be considered in the migration to a 100% VRE future. Socio-economic issues if ignored will result in resistance. There are 20 square kilometres (20 km^2) of land available for RE in Barbados. Partnerships with developers, OEMs, academic institutions, the private sector, and the GoB is crucial.

It was generally considered that there are sufficient skills available in Barbados for the transition to RE especially in the rooftop PV and storage area. Less so for large wind farms and large bio-energy projects and even less so for off-shore wind and other marine technologies.

J.5 Feedback Session 3 – Themes 1 to 3

J.5.1 Renewable options

It was mentioned that energy storage will be important with the evolution to 100% VRE and Hydro Pumped Storage (HPS) should be considered. A further comment was that HPS also provides inertia and fault level and HPS generators can run in SCO mode if designed and specified correctly.

It was mentioned that financing for rooftop PV and battery storage should be made available and possibly based on historical usage. The difference in usage could be used to pay back the installation.

It was also stated that social and other media should be used to encourage the uptake of residential solar PV and battery storage.

It was stated that battery energy storage does come with environmental and waste storage risks.

Off-shore wind is being investigated however offshore wind may be more susceptible to extreme weather events.

The GoB has a policy of not investing in unproven or novel technologies.

Bio-energy options enable baseload/dispatch energy in the 100% VRE vision. Bio-energy options also mesh well with other sectors such as chicken farms, sugar cane, etc. RE demand for these resources could improve the profitability of these farms. As mentioned, King Grass, River Tamarind and Sargassum (seaweed) are bio-energy options.

It was stated that bioenergy is too broad and should be further segregated into gasses, liquids, and solids. Growing and collection technical requirements can be complex. Synergies with transport are possible.

It was stated that plans for a 2 5MW biomass power plant are in motion. Rankin cycle mass burn for 20 MW solid biomass and 5 MW waste. It is envisaged that most of the raw material will be imported. Over a five-year period, local material used. The BWA already have two large bio-waste sewerage collection systems. Photosynthesis storage is an option from the biomass options.

Other CARIB countries are looking at indigenous hydrogen from either electrolysis or natural gas. Costs may be high, but considering relatively high electricity costs in Barbados, hydrogen could be viable.

Again, HPS could be an option but a Public Private Partnership (PPP) could be required. Barbados has high evaporation so enclosed HPS may be required at higher cost.

J.5.2 Energy demand

It was mentioned that not enough attention was being paid to Energy Efficiency (EE). Banning incandescent lights and even migrating from fluorescent lights to LED lights would have an impact on demand. Incentive schemes for EE and reduced import duties on fluorescent and especially LEDs are in place.

It was mentioned that 30% of light bulbs are still incandescent.

The GoB has reduced import duties on Variable Speed Drive (VSD) Air Conditioners (A/Cs). There has been “some uptake” of solar A/Cs. Smart control on commercial and industrial A/C systems can assist with system stability. Currently there is no smart control on A/Cs in Barbados.

The GoB has been exploring “smart buildings” with the government of South Korea in two public buildings with the objective of energy efficiency. The Japanese government is also providing support on smart systems.

It is predicted that in the next five years, PV panels will become cheaper than roofing materials.

J.5.3 Network Operations, Reliability and Resilience

It was mentioned that in previous studies undertaken for BLPC, the impact of RE on the reliability of the power system were evaluated. There are technical solutions available to mitigate the impact of high VRE and inverter-based storage systems such as HPS, SCOs and improved weather forecasting.

It was mentioned that long term storage such as hours and days is a challenge for Barbados and likely to be expensive.

A question was asked whether 100% inverter systems are in fact possible using e.g., grid forming inverters. It seems that the electricity industry is not quite at the point of 100% inverter generating systems. In Barbados’ case, the legacy protection systems require sufficient fault level, so a 100% inverter-based system is not possible.

EVs can provide storage and system frequency support. It was mentioned that it may be possible to replace 6000 EVs per year of the total car population of 120,000.

Barbados should possibly consider ramp-rate requirements for VRE IPP projects to assist with system stability.

J.6 Feedback Session 4 – Themes 4 to 6

J.6.1 Role of Oil and Gas in Barbados

It was suggested that a cost-benefit analysis be done on an LNG industry in Barbados especially if LNG is phased out in 2030. There is currently an RFP in the market issued by BNOCL investigating LNG in Barbados.

Plant efficiency reduces when the fuel is changed from HFO to LNG. Even a transitional LNG arrangement to 2030 would need to investigate the options of onshore re-gasification, FSRUs and containerised LNG.

1.4m cubic feet/day is required for the residential/commercial sectors.

Currently, indigenous natural gas is cheap, so any replacement technology such as electricity would need to be efficient. Some investigation is taking place into low energy induction electric cookers. The price of natural gas has increased recently to provide reasonable return to NPC so natural gas is now comparable with diesel.

Again, moving away from HFO is not simplistic as HFO infrastructure is currently in place for marine fuel and electricity generation.

It was mentioned that the importation of biogas to replace the current natural gas in the residential and commercial sectors would not be commercially viable.

Indigenous gas/oil would be exported or used for bunker/marine fuel.

Beyond 2030, BNOCL will continue to import aviation fuel.

In addition to the 33 MW Energy Bridge, BLPC is investigating an ICE power plant candidate for conversion to biofuels.

J.6.2 Green House Gas Position

Barbados has a GHG position, not through IRENA but through the climate change fraternity (Paris Accord). However, the 100% VRE ambition is a lot more stringent than the current Nationally Determined Contributions (NDCs) so the GHG targets largely become irrelevant.

J.6.3 Policy drivers and the MCA

COVID-19 will likely have an impact on GoB policies.

A mention was made for back-up power plants for critical sectors such as hospitals. Bio-diesel candidates would likely be an option as back-up durations may exceed typical battery energy storage times.

Cost of Unserved Energy (CoUE) likely to cover the costs of conversion of OHLs to UGCs.

More attention should be paid to extreme weather events in the IRRP and building regulations should be improved especially in terms of fixing PV panels to roof structures.

The breakdown of ownership structures for the new RE generation plants should be spelt out more carefully and transparently so all stakeholder “know where they stand”.

Forex flow is included in the MCA.

A real-time database tracking the development of the RE process should be implemented.

J.6.4 Socio-economic dimensions

There have been criticisms of getting correct information from government authorities in terms of applying for and implementing domestic and commercial RE solutions. An education and marketing program to explain the process to citizens should be expedited. Information to citizens could include FiT benefits, tax benefits, financing and pay-back based on electricity use savings, incentives, etc.

Barbados already has over 300 people in Barbados doing PV installations. There are private and government agencies providing training for PV installations. There is however a dearth of skills in large bioenergy and wind projects (on-shore and off-shore).

There are likely to be shortages in skills in the following areas:

- RE dispatch, curtailment, and reconciliation
- Setting up an Independent System Market Operator and or a Single Buyer
- Setting up standard agreements

J.7 Survey Results

At the time of writing the Diagnostic Report, four responses to the MESBE on-line Stakeholder Survey had been received.

Key issues for stakeholder responses are mainly as follows: system resiliency, skills availability, and level, RE land requirements, citizen enfranchisement and the need for diversified and least cost and affordable energy solutions.

A full presentation of the stakeholder survey results can be found in Appendix C.

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