ANNEX 1

PREAMBLE TO THE BERMUDA'S 2026 INTEGRATED RESOURCE PLAN

Date: 3 JULY 2026

As per the Electricity Act (EA) section 40, "every five years or less, as determined by the Authority, or as directed by the Minister, the Authority shall issue a notice requesting an Integrated Resource Plan proposal from the TD&R Licensee"[1]. To fulfil the mandate, the Regulatory Authority of Bermuda (RA) issued the Guidance and request for an Integrated Resource Plan (IRP) proposal from BELCO in November 2022. BELCO then submitted its first proposal to the RA in November 2023, which was later published on the RA's website for public comment and feedback.

After the consultation process concluded, the RA considered the public's comments, its own independent analysis, and the information provided by BELCO throughout the process to issue a set of comments to BELCO for integration into their IRP proposal. Thereafter, the RA continuously cooperated with BELCO, holding several workshops and conversations with BELCO, for the finalization of the IRP and final modelling stage.

The RA had shared a comprehensive list of observations and concerns pertaining to BELCO's draft IRP dated November 2023 covering a wide range of issues (e.g. level of battery storage required, detail and process for selecting the preferred scenario). However, we are now satisfied that those concerns have been addressed in the final IRP version attached.

A wide range of scenarios have been simulated – testing various degrees of renewable energy deployment, different power generation technologies and different types of fuel. Indicators stemming out of simulations include renewable energy penetration, carbon emission reductions, but also estimated variation in consumer prices.

The analysis acknowledges that it is necessary to reconcile two fundamental priorities for Bermuda:

1. Decarbonization and improved resilience – through resource diversity, deployment of renewables, and/or using lower emitting fuels
2. Affordability of electricity to all consumers

In light of the above, the analysis identifies two scenarios that place different emphasis on these principles. Scenario P2F, which retains the current on-island fuel mix, involves an ambitious short-term renewable energy development programme and supports a high degree of energy independence through resource diversity, with relatively limited disruption and no greater exposure to fuel price uncertainty than at present. However, it could also lead to a significant increase in costs for consumers. By contrast, scenario P2N, which shifts fuel supply towards liquefied natural gas while delaying renewable energy deployment, delivers by far the

[1] Electricity Act 2016, Section 40(1)

lowest cost of energy supply, but increases Bermuda's reliance on LNG as the primary fuel. Taken in isolation, neither scenario provides a fully satisfactory pathway.

Scenario P4N, which combines an ambitious expansion of renewable energy with a transition to liquefied natural gas as the primary fuel, therefore emerges as the compromise scenario that best balances decarbonisation with the need to minimise the financial impact on consumers. It offers a hybrid approach to decarbonisation in Bermuda, combining new solar and wind capacity with a move away from heavy fuel oil towards lower-emitting LNG for thermal generation, while continuing to prioritise affordability, a central principle of the draft 2026 National Electricity Sector Policy.

Table 1. Extracted 2035 Scorecard with Key Performance Indicators from BELCO's IRP Proposal for Scenarios P2F, P2N, and P4N[2]

Portfolio	Total Expenditure ($ Billions)	Average annual rate increase until 2035 (%)	GHG Emissions Reductions (%)	Renewable energy generation (%)	Operation Risk (%)	Resource Diversity (HHI)	Max LOLP (%)
P2F	2.59	1.09%	49%	50%	50%	5,259	0.049%
P2N	2.55	0.65%	37%	16%	5%	7,065	0.022%
P4N	**2.57**	**1.09%**	**64%**	**51%**	**5%**	**5,336**	**0.016%**

Table 2. Extracted 2050 Scorecard with Key Performance Indicators from BELCO's IRP Proposal for Scenarios P2F, P2N, and P4N3

Portfolio	Total Expenditure ($ Billions)	Average annual rate increase until 2035 (%)	GHG Emissions Reductions (%)	Renewable energy generation (%)	Operation Risk (%)	Resource Diversity (HHI)	Max LOLP (%)
P2F	8.51	1.32%	48%	51%	60%	2,055	0.068%
P2N	7.89	0.53%	64%	52%	10%	5,178	0.022%
P4N	**7.85**	**0.56%**	**64%**	**52%**	**10%**	**5,178**	**0.016%**

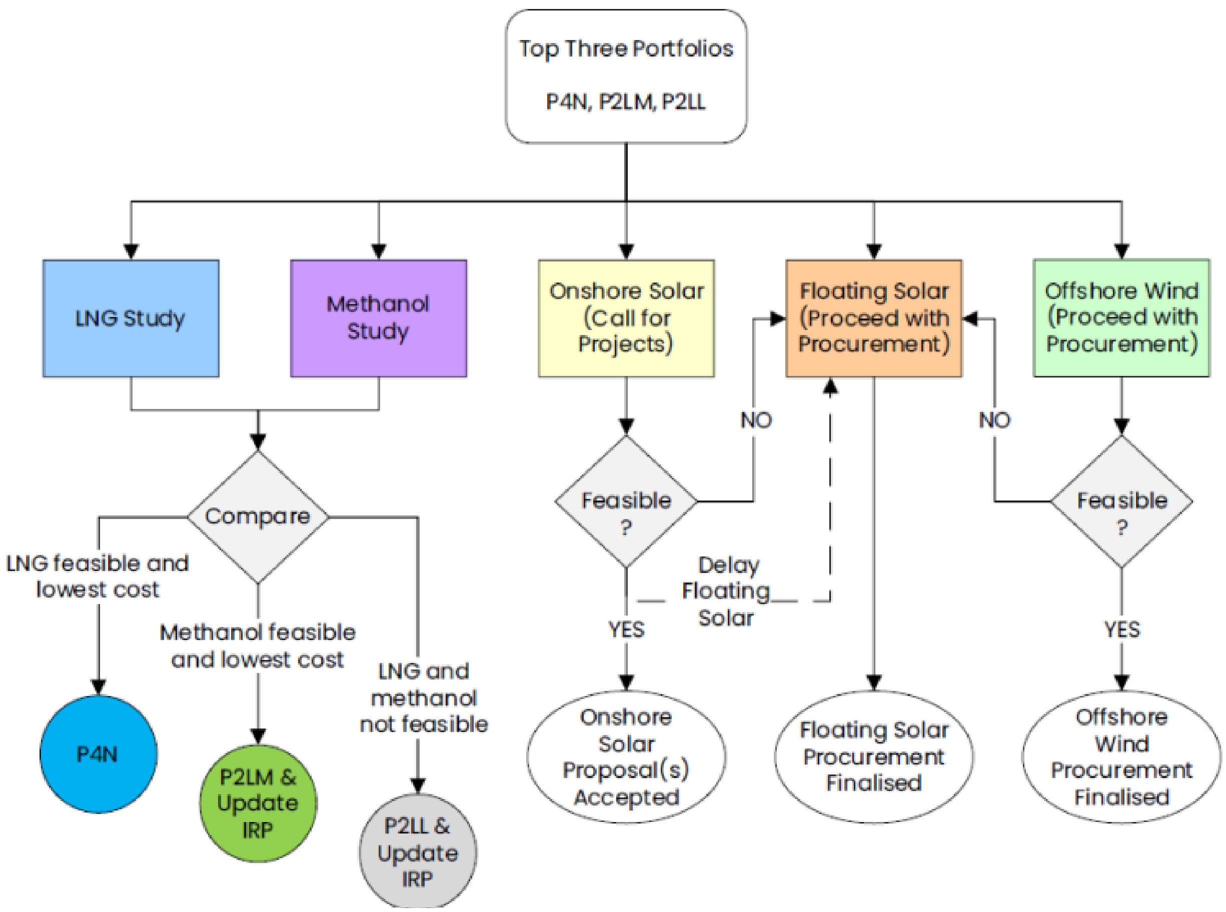
[2] Extracted from Table 7 of BELCO's IRP Proposal, 24 June 2026

[3] Extracted from Table 9 of BELCO's IRP Proposal, 24 June 2026

The RA would like to highlight that even though P4N is the preferred scenario, the IRP is not a project plan, but a planning framework. The selection of the P4N pathway does not in any way pre-empt the approval to proceed with LNG infrastructure project development or LNG use on the island.

What the IRP rightly concludes is the immediate need to initiate detailed studies and processes including but not limited to: a study on LNG, its costs, and feasibility on the island. The study (whose results will be made public) will aim to precisely confirm the underlying assumptions (on infrastructure feasibility, costs, fuel prices, etc.) that have led to the selection of this scenario. Failing this, Figure 1 (shown below) in the final IRP indicates a structured plan to investigate assumptions underpinning other scenarios which scored relatively well in the analysis and feed back into the next cycle of IRP update.

Figure 1. Implementation Pathway and Decision Tree[4]



[4] Figure 15 of BELCO's IRP Proposal, 24 June 2026

In parallel and by no means less importantly, the preferred scenario outlines that we should double down our efforts to accelerate renewable energy implementation. However, similarly, the IRP approval does not pre-empt the approval of solar and wind investment or infrastructure. There are various steps, studies, processes, and approvals that are still required before these technologies are deployed. Similarly, the IRP is a living document, and while the current IRP modelling prioritizes onshore solar, followed by offshore wind, and then floating solar, the RA will keep up to date on technology developments and incorporate them into future iterations of the IRP, as appropriate. Similarly, while onshore solar PV is the most economically attractive of the three technologies, land constraints in Bermuda limit the technology's expansion, and the IRP has been modelled to account for those constraints. However, if more land were to become available for onshore solar PV in the future, the RA would incorporate such development in the future IRP process.

For now, offshore wind and floating solar procurements should continue, and the RA will continue to seek government support to identify public land suitable for the procurement of bulk generation solar farms. Initiatives supporting the penetration of behind-the-meter solar panels are also set to persist – with their cumulative capacity set to increase to 35 MWAC over the next 25 years in the preferred scenario.

The RA acknowledges that the IRP is a planning framework that impacts all Bermudians. Rather than a traditional public consultation, the RA will run a dedicated public information campaign designed to help Bermudians fully understand the IRP — what it is, what it does, and what it does not decide. This will be complemented by a series of targeted roundtables with focused stakeholder groups, offering a forum for more detailed discussion, questions, and feedback. Together, these efforts are intended to give the public the clarity they need and to address any concerns.

BELCO

Bermuda's 2026 Integrated Resource Plan

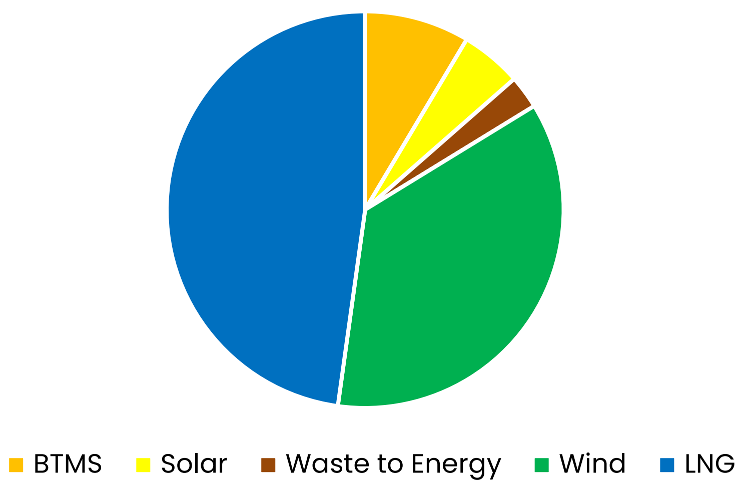
Finalised: 3 July 2026

CRA Charles River Associates

Executive Summary

This Integrated Resource Plan (IRP) sets out Bermuda Electric Light Company Limited (BELCO)'s recommended pathway for Bermuda's electricity future. Based on the analysis completed for this IRP update, offshore wind, solar and liquified natural gas (LNG) under Portfolio P4N is identified as the preferred pathway because it provides the strongest overall balance of affordability, reliability, renewable energy progress, and flexibility under uncertainty. P4N consists of growing behind-the-meter solar (BTMS) to an installed capacity of 35MW, 10 MW of additional onshore solar, 60 MW of offshore wind, and battery storage, anchored by a switch to LNG for firm generation allowing Bermuda to reduce emissions, contain long-term costs, and maintain dependable service on an isolated grid.

Figure 1: Energy Mix After 2035 for Preferred Portfolio P4N



Bermuda's electricity system faces a distinct set of challenges typical of small island grids. Electricity is generated locally, with no ability to import power during shortages. The system relies heavily on imported fuels, making costs sensitive to global price movements and supply chain disruptions. Land availability for large-scale renewable projects is limited, while customer expectations for reliability remain high. At the same time, national policy calls for a gradual transition toward a lower-carbon electricity system that remains affordable and resilient.

The purpose of this IRP is to help navigate these competing pressures. It does not approve specific projects or commit to fixed investments. Instead, it compares different long-term resource pathways and identifies a preferred strategic direction that best balances affordability, reliability, sustainability, and flexibility under uncertainty. Detailed modelling results, technical assumptions, and supporting analysis are provided in appendices to keep the main document accessible to a general audience.

To inform the plan, multiple portfolios were assessed representing different combinations of generation, storage, renewable energy, and demand-side actions. These portfolios were evaluated over a long-term planning horizon to 2050 and tested against a range of plausible future scenarios. Each option was compared using consistent metrics drawn from Regulatory Authority guidance, including total system cost, reliability performance, emissions outcomes, operational risk, and practical feasibility on an island system.

The analysis indicates that Portfolio P4N is the preferred pathway under current assumptions. It stands out because it captures the value of LNG as a lower-cost, dispatchable fuel for reliability, the value of renewables in reducing emissions and fuel exposure, and the value of flexibility in preserving future options as technology, policy, and market conditions evolve. Rather than relying on a single resource type, P4N combines firm generation, offshore wind, onshore solar, and battery storage in a way that is practical for Bermuda's isolated system.

A central feature of the preferred pathway is a least-regret approach to decision-making. Recognising uncertainty around future fuel prices, technology costs, permitting timelines, and customer adoption of new technologies, the IRP avoids irreversible commitments. Fuel decisions are treated as staged and conditional, with an emphasis on flexible procurement structures and infrastructure options that can adapt over time. This approach is intended to reduce the risk of stranded assets while preserving the ability to respond to future developments.

Reliability and resilience remain core priorities throughout the plan. The modelling shows that even with increasing levels of renewable generation and battery storage, Bermuda's electricity system will continue to require firm, dispatchable capacity to meet evening peak demand and to manage periods of low renewable output or system disturbance. The preferred pathway maintains adequate reserve margins and operational flexibility to ensure reliable service under a wide range of operating conditions.

The IRP also outlines near-term actions within a five-year procurement window. These include a call for onshore solar projects, continuing procurement of offshore wind and floating solar options, undertaking independent evaluation of alternative fuels such as liquefied natural gas (LNG) and methanol, and maintaining and upgrading existing generation assets to support reliability. All future actions remain subject to regulatory approval, procurement processes, and further detailed studies.

Importantly, this IRP is designed as a living planning framework. It will be reviewed and updated periodically, as required under the Electricity Act 2016, to reflect new information, changing policy direction, technology developments, and observed system performance. Signposts and pivot strategies are identified to indicate when reassessment may be needed.

In summary, the 2026 Integrated Resource Plan sets out a pragmatic, flexible pathway for Bermuda's electricity future. It demonstrates that it is possible to reduce emissions, manage long-term costs, and preserve high levels of reliability on an isolated island grid, while retaining the ability to adapt as conditions evolve.

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1 What an Integrated Resource Plan Does

An IRP is a forward-looking planning exercise that evaluates how electricity needs (demand) can be met over time using a combination of supply-side resources (generation and storage) and demand-side resources (such as energy efficiency).

An IRP determines the procurement actions needed to meet that demand reliably and at lowest reasonable cost, while balancing policy goals like sustainability.

In practical terms, an IRP helps answer questions such as:

- How much electricity might customers need in the future?
- What mix of resources could meet that demand reliably?
- What are the costs, reliability, and environmental factors of different options?

The IRP is intended to guide long-term decision-making, but it does not replace the detailed engineering, procurement, and regulatory work required to deliver individual projects. It does not approve specific projects but provides a structured way to compare different future resource mixes and identify a preferred strategic direction.

Specifically, this IRP is not:

- A project-by-project construction plan (it does not provide final designs, permits, or engineering drawings).
- An approval of specific projects or sites (future projects remain subject to procurement, permitting, and regulatory review).
- A guarantee that a particular technology will be built on a specific date (assumptions and timelines can change as real-world conditions evolve).
- A substitute for ongoing system operations and near-term reliability planning (day-to-day operating decisions are managed through operational processes, not the IRP).

For this reason, the IRP should be read as a planning tool and a public-facing roadmap. It explains the direction of travel, the options considered, and the conditions under which decisions may need to be revisited.

The IRP is not a day-to-day operating plan or a final commitment to build specific projects. Instead, it provides a long-term decision framework to help BELCO, the Regulatory Authority of Bermuda (RA), and the public understand the differences between different pathways and to guide future approvals, procurements, and investments.

1.1 Planning horizon and decision framework

This Integrated Resource Plan looks ahead to 2050 to help Bermuda consider how its electricity system may evolve over the long term. While integrated resource plans are often developed over a 20-year horizon, extending the planning period to 2050 allows the IRP to reflect internationally recognised timelines for long-term decarbonisation and net-zero emissions goals. Looking further into the future also helps ensure that near-term decisions are made with an understanding of their long-lasting impacts on infrastructure, costs, and system flexibility.

At the same time, this IRP is not a single, fixed plan for the next 25 years. Instead, it is designed as a rolling planning framework that supports informed decision-making over shorter, actionable timeframes. The primary decision focus of this IRP is the next five years, which aligns with the procurement window for new resources, upgrades to existing assets, and demand-side initiatives. This approach allows BELCO and the RA to focus on decisions that can realistically be implemented in the near and medium term, while keeping longer-term options open as conditions evolve.

This structure is consistent with the Electricity Act 2016, which requires the Integrated Resource Plan to be updated on a regular basis. The Act anticipates that IRPs will be revisited every five years, reflecting changes in demand, technology advancement and performance, fuel markets, policy direction, and system conditions. As a result, this IRP should be viewed as one step in an ongoing planning process rather than a final or permanent blueprint. Future IRP updates will reassess assumptions, evaluate new information, and adjust the preferred pathway as needed to continue serving the public interest.

By combining a long-term planning horizon with a shorter-term decision framework and regular updates, the IRP balances foresight with flexibility. This approach helps ensure that Bermuda's electricity system remains reliable and affordable in the near term, while retaining the ability to adapt over time as technologies mature, costs change, and policy objectives evolve.

1.2 Policy and legislative context

This Integrated Resource Plan is prepared within the legislative and policy framework that governs Bermuda's electricity sector. The primary statutory foundation for the IRP is the Electricity Act 2016, which establishes the requirement for integrated resource planning as a tool to support the provision of electricity that is safe, reliable, and affordable. The Act assigns the Regulatory Authority responsibility for oversight of the electricity sector and for issuing guidance on the preparation, review, and updating of Integrated Resource Plans.

The Electricity Act is supported by energy policies that provide strategic direction for the sector. The Fuels Policy 2018 guides how Bermuda manages imported fuels used in electricity generation and recognises the importance of fuel security, affordability, and environmental performance. The Fuels Policy does not mandate specific fuel outcomes, but instead supports the evaluation of alternatives over time, considering cost, feasibility, and risk. This IRP reflects that approach by assessing fuel options within a structured planning framework rather than pre-selecting specific outcomes.

The National Electricity Sector Policy issued for consultation in April 2026 provides the current policy context for electricity planning in Bermuda. This policy places affordability, reliability, resilience, and equity at the centre of decision-making, while supporting a gradual and flexible transition toward lower-carbon electricity. It deliberately avoids prescriptive technology or fuel mandates and instead directs the IRP to identify practical, least-cost pathways that reflect Bermuda's unique characteristics as a small, isolated island system with limited land availability and exposure to global fuel price volatility.

In addition to legislation and policy, the Regulatory Authority has issued guidance that shapes how this IRP is developed and assessed. The Regulatory Authority's February 2026 guidance confirms expectations around transparency, comparability of portfolios, treatment of uncertainty, and the avoidance of premature commitment to specific technologies or fuels. It also sets out modelling assumptions, caps, and evaluation principles that are reflected throughout this IRP. The guidance reinforces that the IRP is a planning document intended to inform future decisions, not to approve specific projects or investments.

Taken together, the Electricity Act, the Fuels Policy, the National Electricity Sector Policy, and the Regulatory Authority's guidance establish a clear framework for this IRP. Within that framework, the IRP is intended to provide a structured, evidence-based assessment of how Bermuda's electricity needs may be met over time, while maintaining flexibility to adjust as costs, technologies, policies, and system conditions evolve.

The IRP is being updated now in 2026 because the RA, under section 44 of the Electricity Act 2016, has directed BELCO (as the Transmission, Distribution and Retail (TD&R) Licensee) to prepare a final IRP that incorporates public comments and the RA's guidance, with a required submission date of 16 June 2026.

2 Bermuda's Electricity System Today

Bermuda's electricity system is operated as a single, island-wide network, with BELCO holding the sole TD&R license. BELCO is responsible for delivering electricity to more than 36,000 customers and holds a licence to provide bulk generation for the island.

Electricity is generated primarily at BELCO's central power station in Pembroke, which uses fuel-oil-fired reciprocating engines and gas turbines. This centralised generation is supplemented by a small but growing contribution from third-party resources, including solar generation and the Tynes Bay waste-to-energy facility, as well as customer-owned behind-the-meter solar installations.

As an isolated island system, Bermuda cannot import electricity from neighbouring grids during shortages or emergencies. Limited land availability, dependence on imported fuels, and exposure to supply chain disruptions make long-term planning and system resilience especially important.

The system also faces ongoing challenges. Electricity consumption per person is relatively high, customer expectations for reliability are strong, and opportunities for large-scale renewable development are constrained by limitations related to land availability and natural resources. These factors shape how Bermuda must balance reliability, affordability, and sustainability as the electricity system evolves.

2.1 Who provides electricity in Bermuda?

The TD&R Licensee transmits and distributes electricity to its customers with energy from a set of BELCO-owned generation and independent power producers (IPPs). BELCO's central power station, located in Pembroke, includes a mix of reciprocating engines and gas turbines running on fuel oil with a total nameplate capacity of 142MW. Additionally, the TD&R Licensee contracts a small amount of energy from a solar plant and waste-to-energy (WTE) facility via power purchase agreements (PPAs).

Table 1: Installed Capacity of Current Resources on Island.

Resource	Installed Capacity 2026
BELCO	142 MW
BELCO Battery Energy Storage System (BESS)	10 MW, 5.5 MWh
Tynes Bay	7.3 MW
Solar Finger	6 MW_{AC}
Behind-the-Meter Solar	14.5 MW_{DC} or 12 MW_{AC}
Behind-the-Meter Batteries	1 MW, 2.7 MWh

2.2 Key challenges for Bermuda's electricity system

Bermuda's electricity system faces a set of interrelated challenges that are typical of small island grids. The most important challenges relate to cost volatility, emissions, aging infrastructure, and the constraints of operating an isolated island system.

2.2.1 Cost volatility (fuel and supply chain exposure)

Electricity in Bermuda has historically been generated primarily using imported fuel oil. This makes costs sensitive to international fuel prices, shipping and logistics, and other external factors beyond Bermuda's control. Because the system is relatively small, changes in fuel costs can translate quickly into changes in overall system costs. The cost challenges revolve around relatively high energy consumption per capita, high reliability performance and customer expectation coupled with limited land and natural resource availability for renewable generation.

2.2.2 Emissions (carbon intensity and local air quality)

A fuel-oil-based generation mix results in higher greenhouse gas emissions than a system with more renewable generation. It can also contribute to local air pollutants, increasing the importance of transitioning toward cleaner resources over time while maintaining reliability.

2.2.3 Aging infrastructure (asset replacement and system performance)

Much of Bermuda's electricity system depends on large, central generating units and supporting grid infrastructure that must be maintained, refurbished, and eventually replaced. Planning is required to manage equipment lifecycles in a way that preserves reliability and limits unexpected costs for customers.

2.2.4 Island constraints (no interconnection, land limits, and resilience needs)

As an isolated island system, Bermuda cannot import electricity during generation shortages. The island also has limited land availability for utility-scale projects and is exposed to delivery and supply-chain disruptions. These constraints increase the value of a diversified, resilient resource mix and a clear long-term plan.

3 Planning Objectives

The goal of the IRP is to ensure that Bermuda has electricity that is affordable, reliable, and increasingly sustainable. Achieving this requires a balanced approach that includes:

- Strengthening and modernising the grid
- Expanding renewable energy where technically and economically feasible
- Reducing reliance on imported fuel oils as cleaner, cost-effective alternatives become available
- Ensuring that the system remains resilient in the face of extreme weather events, supply-chain risks, and global oil price volatility

In short, the IRP sets out a long-term pathway for Bermuda's energy future while helping ensure that the electricity system remains reliable and affordable for customers. To understand which long-term pathway best serves Bermuda, the IRP compares portfolios using a scorecard of key performance indicators (KPIs) drawn from the Regulatory Authority's guidance.

The guidance requires that portfolios be compared through a series of separate rankings rather than a single blended score. Doing so allows portfolio trade-offs to remain transparent and enables decision-makers to clearly see how each portfolio performs on affordability, decarbonisation, reliability, and system practicality.

Under this approach, each metric produces its own independent ranking. In line with the guidance, scenarios are to be ranked across the following metrics:

- Total Expenditure (TOTEX) by 2035, ranked from lowest to highest
- TOTEX by 2050, ranked from lowest to highest
- Carbon emission reduction by 2035, ranked from highest to lowest
- Carbon emission reduction by 2050, ranked from highest to lowest
- Renewable generation % total generation by 2035, ranked from highest to lowest
- Renewable generation % of total generation by 2050, ranked from highest to lowest
- Operational risk by 2035, ranked from lowest to highest
- Operational risk by 2050, ranked from lowest to highest
- Resource diversity by 2035, ranked from lowest to highest
- Resource diversity by 2050, ranked from lowest to highest

Taken together, this scorecard framework helps ensure that the preferred portfolio is selected through a balanced and transparent comparison of cost, emissions, renewable progress, operational risk, and diversity, rather than by relying on any single measure alone.

3.1 Customer affordability- How Much Each Portfolio Costs

Keeping electricity affordable is one of the IRP's core goals. To understand how different futures affect long-term costs, the IRP evaluates each portfolio using TOTEX, that captures all capital, fuel and operational expenditure.

3.2 Customer affordability- Impact on Customer Rates

Whilst economic metrics such as net present value (NPV) and TOTEX present how portfolio costs change over time, the bundled rates of electricity also change over time. It is important that these cost implications are clear to households and businesses.

This IRP includes bundled rates for electricity excluding duty and taxes, providing customers practical methods of comparing the future cost of electricity.

3.3 Reliability and Resilience

Reliability is essential for an island that cannot import electricity during shortages. In the IRP, reliability refers to the system's ability to meet customer demand under normal operating conditions, supported by sufficient firm capacity resources that can be counted on to produce electricity when needed.

Resiliency goes a step further. It describes the system's ability to withstand and recover from unexpected events, such as severe weather, equipment failures, fuel supply disruptions, delays in obtaining critical spare parts, or rapid changes in renewable output. A resilient system can maintain service, or restore it quickly, even when conditions are far from normal.

It should be noted that a robust vegetation management plan is critical to system resilience and the integrity of power infrastructure. Effective vegetation management by all stakeholders is required to maintain safe clearances, reduce outage risk by minimizing tree-related contact with overhead lines, and support reliable service under adverse conditions.

As renewable energy grows, BELCO's engines must operate more flexibly, running at lower output and starting and stopping more often to balance changes in solar and wind production. While this reduces fuel consumption, it increases mechanical stress and operational risk over time.

To evaluate these risks, the IRP uses the operational and environmental risk indicator set out in the Regulatory Authority's guidance, scored from 0–100%, where higher values reflect greater operational stress on the system.

This KPI is intended to capture at least two considerations: first, the risk of accelerated engine ageing and technical challenges associated with lower running rates, more frequent start-ups, and more frequent shutdowns; and second, where applicable, the environmental and infrastructure-planning risks associated with introducing LNG as a primary fuel in Bermuda.

This ensures that the preferred pathway maintains reliable service during all conditions both day-to-day operations and unexpected events while supporting Bermuda's transition to cleaner energy.

3.4 Environmental stewardship

Bermuda's long-term energy policies call for a cleaner electricity system that reduces emissions and increases the use of renewable energy. To understand how each future pathway performs environmentally, the IRP focuses on two key goals:

- Reducing carbon emissions
- Increasing the share of renewable energy

In addition to carbon emissions, the IRP also considers local air-quality impacts, consistent with the requirements of Bermuda's *Clean Air Act 1991*. This includes pollutants such as sulphur oxides (SO_x), nitrogen oxides (NO_x), and particulates or soot. Fuel choice, such as the continued use of intermediate fuel oil, switching to lighter fuels, introducing LNG or methanol have different implications for these emissions.

The IRP also reviews broader environmental and infrastructure considerations, such as the requirements and potential impacts of introducing LNG, including methane leakage and permitting needs. These factors ensure that Bermuda's energy transition protects the environment while supporting reliability and affordability.

3.5 Resource diversity and land use

Bermuda's energy future must balance the need for dependable electricity with the realities of limited space and a small, isolated grid. To support long-term planning, the IRP evaluates resource diversity, one of the Regulatory Authority's required comparison metrics. Scenarios that include a mix of technologies such as firm generation, solar PV, offshore wind, battery storage, and demand-side resources provide more flexibility to adapt to future changes in technology, cost, and policy.

Land use is also a critical consideration for Bermuda. With limited available land and many competing uses, new energy infrastructure must be carefully sited to minimise impacts on residential areas, natural habitats, and community spaces. The IRP therefore considers:

- The land area required for onshore solar installations
- Opportunities to reduce land pressure through offshore wind and floating solar
- The siting needs of battery storage and supporting infrastructure

Battery Energy Storage Systems also require thoughtful siting. International safety standards call for small exclusion zones or separation distances around battery units to manage fire-safety risks and ensure emergency access. These spacing needs are included in the IRP's land-use considerations.

By examining both resource diversity and land use, the IRP ensures that the preferred portfolio is not only technically robust, but also practical to build within Bermuda's physical constraints. This supports a long-term energy strategy that balances environmental stewardship, community considerations, and the realities of limited island land availability.

4 Load Forecast: Understanding Future Electricity Needs

Electricity sector planning starts with a simple question: How much power will Bermuda need in the years ahead?

The load forecast helps answer that question by estimating future electricity use, peak demand, and how those needs may change over time. Electricity planning must meet the highest hour of demand, not just total annual energy use.

This IRP indicates that Bermuda's overall electricity demand is expected to remain relatively stable, but that does not mean planning is simple. Future needs can still be affected by changes in weather, economic activity, customer-owned solar, energy efficiency programmes, and the growing use of electric vehicles. Because Bermuda is an island system with no ability to import electricity from elsewhere, understanding both everyday demand and periods of highest demand is essential. In short, the load forecast gives Bermuda a practical starting point for deciding what resources the system may need, when they may be needed, and how much flexibility should be built into the plan.

The Bermuda load forecast was developed through a process that incorporated projections across multiple sectors. To achieve this, Belco performed a forecast of customer growth and average energy use at each class level then aggregated each segment to yield a system-level forecast of total energy sales, total energy requirements, and the system peak. Monthly forecasts were developed using a combination of multivariate regression models and trending techniques.

BELCO's 2022 retail energy sales by customer class are presented in Figure 2.

The Residential class is the largest with nearly 33,000 customers, comprising ~46% of 2022 total retail sales. The Demand metered class comprised ~39% of 2022 retail sales but included just over 200 large customers. Smaller businesses are included in the Commercial class with over 3,000 businesses that account for ~15% of 2022 BELCO retail electric sales. Note that customers with distributed energy resources and bi-directional metering are embedded within these three customer classes for forecasting purposes.

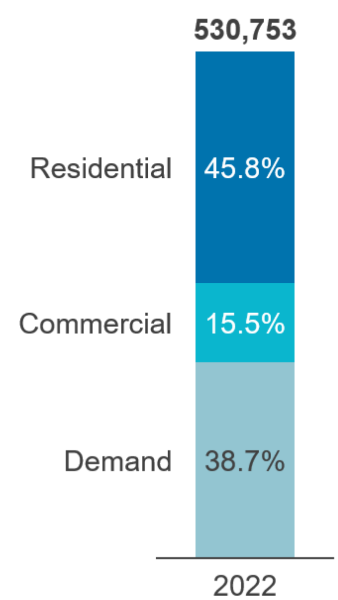


Figure 2: 2022 electricity sales by class.

The following sections detail the data sources, methodologies, and forecast results at a class level and for the total BELCO system.

4.1 How demand is expected to change

Electricity demand in Bermuda has remained relatively flat in recent years and is expected to remain stable over the long term. Residential consumption has declined due to efficiency improvements, while commercial and large-customer demand has stabilized following the pandemic.

The base demand forecasts presented purposely exclude the impacts of behind-the-meter self-consumption from customer-owned solar installations, electric vehicles (EVs), and any newly implemented demand-side management (DSM) programs or energy efficiency programs. These key drivers of electricity demand change are independently forecasted to understand the system's resiliency to different futures.

4.2 Key drivers of change

This IRP distinguishes between trends that are already visible today and future developments that cannot be predicted with confidence. The island will be subject to the operational constraints of an isolated grid for the foreseeable future.

Unknown futures are the variables that may change materially over time and affect generation resource selection. These include the pace of electric vehicle adoption, the amount of behind-the-meter solar and battery uptake, future fuel prices, technology costs, policy developments, permitting and project delivery timelines, and broader economic or weather-related conditions. Because these factors are uncertain, the IRP does not assume that one forecast will be exactly right. Instead, it tests portfolios across multiple scenarios and emphasizes flexibility so that decisions can be adjusted if future conditions differ from today's expectations.

Key uncertainties modelled in different scenarios (TDD, Base and HCP) include electric vehicle adoption, behind-the-meter solar, and participation in demand side management (DSM) and energy efficiency programs.

4.2.1 Electric Vehicles

Electric vehicles are expected to become more common in Bermuda over the planning period. As drivers switch from petrol and diesel vehicles to electric alternatives, electricity consumption will increase, even as energy efficiency improvements continue in homes and businesses.

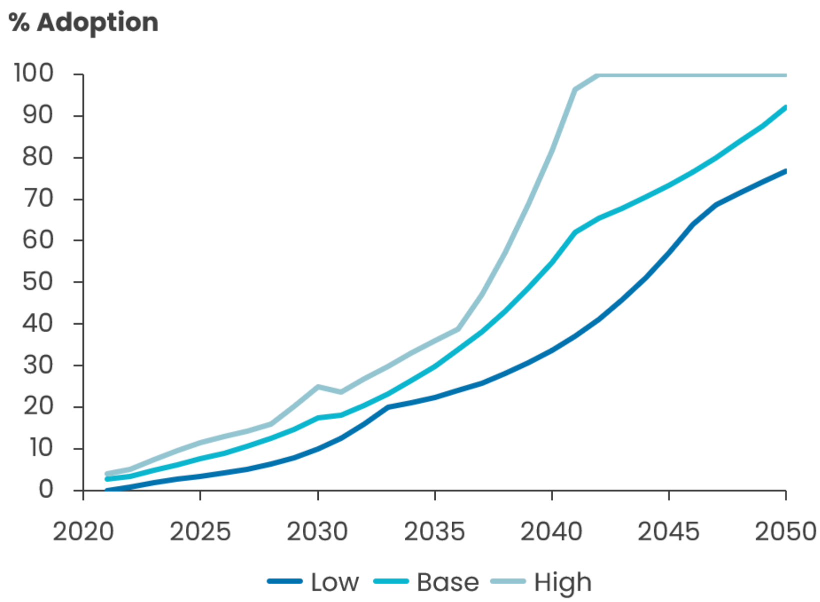
The Integrated Resource Plan does not assume a single outcome for electric vehicle uptake. Instead, it considers a range of possible adoption pathways to reflect uncertainty around vehicle costs, customer preferences, charging availability, and wider transport policy. These pathways are illustrated in the electric vehicle adoption scenarios shown in Figure 3, which indicate gradual growth over time rather than sudden changes.

Electric vehicles mainly affect total electricity use, and depending on customer charging behaviour, may increase peak system demand. Charging is assumed to occur primarily at home.

These assumptions are incorporated into the overall demand forecast to ensure the electricity system can continue to operate reliably under different future conditions. Detailed modelling assumptions, including vehicle numbers, energy use, and charging behaviour, are provided in the technical appendices to this report.

Figure 3 shows the range of possible electric vehicle adoption pathways considered in the 2026 IRP. The scenarios reflect uncertainty in future uptake and illustrate various levels of growth over time, rather than a single forecast, to support flexible and resilient electricity system planning.

Figure 3: Electric Vehicle Adoption Scenarios in Bermuda



4.2.2 Behind-the-meter solar

Behind-the-meter solar refers to small-scale solar photovoltaic systems installed on customer premises, typically on rooftops or building sites, and connected on the customer side of the electricity meter. Electricity generated by these systems is primarily used to meet on-site demand, with any excess generation exported to the grid in accordance with applicable tariff and interconnection arrangements.

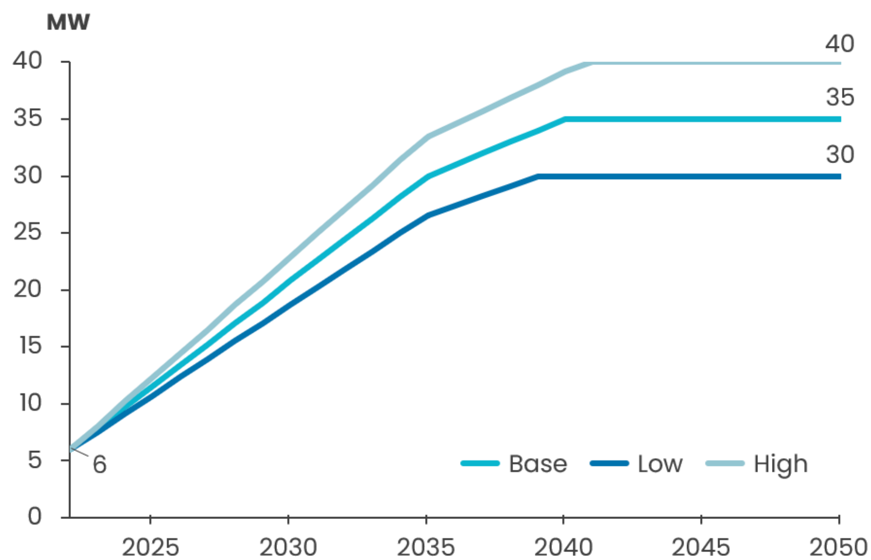
BTMS has grown steadily in Bermuda and represents a form of distributed energy resource rather than bulk generation. While these systems reduce the amount of electricity purchased from the grid by participating customers, they do not eliminate reliance on the grid. Specifically, customers with BTMS, still require electricity service, particularly during evening periods, cloudy conditions, or system peaks. Most rooftop solar produces electricity during the day, while Bermuda's highest demand occurs in the evening. As a result, BTMS affects system demand patterns and energy flows but does not replace the need for firm, centrally managed capacity.

From an integrated resource planning perspective, BTMS is treated as a demand-side influence rather than as a controllable supply resource. The IRP reflects BTMS through assumptions about future load, net demand, and customer behaviour, rather than by selecting or approving individual systems. The scale, location, and timing of BTMS installations are driven by customer investment decisions within the policy, tariff, and regulatory frameworks established by the Regulatory Authority.

High levels of BTMS penetration can introduce operational considerations for the electricity system, including changes to daytime net load, reverse power flows on distribution feeders, and increased ramping requirements in the evening. These impacts are addressed through distribution planning, grid code requirements, and ongoing system studies, rather than through the resource selection process itself.

The IRP does not set targets for behind-the-meter solar deployment, approve specific projects, or guarantee export capacity. Instead, it incorporates reasonable assumptions about future BTMS uptake as shown in Figure 4 to ensure that long-term planning remains aligned with expected customer behaviour while maintaining system reliability, affordability, and safety for all users.

Figure 4: Behind-the-Meter Solar Adoption ($1MW_{AC} = 1.2MW_{DC}$)



4.2.3 Demand Side Management

DSM refers to programmes and measures that reduce or shift electricity consumption by customers, rather than supplying additional electricity from generation resources. DSM includes both energy efficiency measures, which permanently reduce electricity use, and demand response actions, which shift consumption away from peak periods.

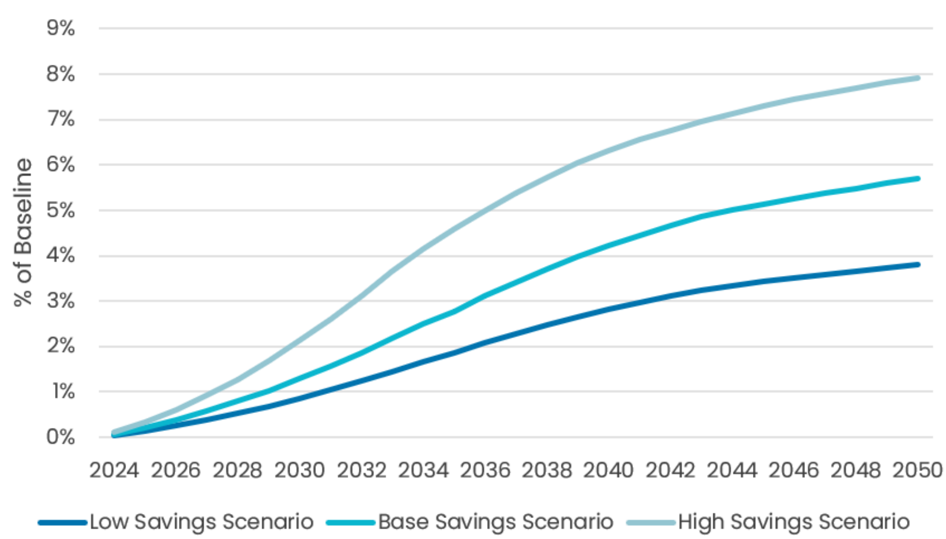
The DSM assumptions build on programmes that are already in place or have been previously assessed, including residential, commercial, and demand-metered customer measures. These measures are consistent with the policy direction set out in the National Electricity Sector Policy 2026 and with the Electricity Act 2016, which recognises demand-side resources as a legitimate means of meeting future electricity needs alongside generation.

The DSM scenarios in Figure 5 shows cumulative energy savings expressed as a percentage of baseline electricity demand. The baseline represents forecast electricity consumption in the absence of new DSM measures. As illustrated in the graph, DSM delivers gradually increasing savings over time, reflecting the cumulative effect of appliance upgrades, building improvements, and other efficiency actions as they are adopted across the customer base. The graph does not imply that DSM eliminates the need for new generation or firm capacity. Instead, it demonstrates how DSM reduces overall energy requirements and moderates future growth in demand, which in turn lowers the scale and timing of supply-side investments required to maintain reliability. DSM impacts are incorporated directly into the load forecast used for system planning. This means that the reduced demand shown as a percentage of baseline is already reflected in the net load that the IRP seeks to serve. This approach aligns with Regulatory Authority guidance to clearly distinguish between demand-side assumptions and selectable supply-side options.

While DSM provides clear system benefits, its achievable scale is constrained by customer participation, programme design, and practical limits on efficiency improvements. For this reason, the IRP does not assume aggressive or transformative reductions in demand. The DSM levels shown in the graph are intended to be realistic and achievable under current policy and programme settings, with further technical detail on measure screening, costs, and savings provided in the appendices.

Finally, DSM contributes to broader IRP objectives beyond energy reduction alone. By lowering electricity consumption relative to baseline demand, DSM helps reduce fuel use, limit emissions, and improve system resilience, while supporting affordability for customers. These benefits complement, but do not replace, the need for investment in generation, storage, and grid infrastructure to ensure a reliable electricity supply for Bermuda over the planning horizon.

Figure 5: Demand Side Management Savings Scenarios



5 Options for Meeting Bermuda's Energy Needs

The IRP process evaluates both demand-side resources, such as energy efficiency and demand response and supply-side resources, including solar, offshore wind, energy storage, and cleaner dispatchable generation. This section summarizes these resource options conceptually. Detailed modelling assumptions and cost data are provided in Appendices D–F.

5.1 What was studied

This IRP evaluates how Bermuda's electricity system could meet customer needs from today through 2050 under a range of plausible futures. The analysis looks at both the resources that generate electricity and the actions that can reduce or shift electricity demand, with a focus on maintaining reliability while managing costs and reducing emissions over time.

To reflect key decisions facing the system, multiple portfolios, as shown in Table 2, were assessed that vary in how existing thermal generation is maintained, retired, or converted over time. These include a stay the course case as well as options that switch the existing fleet to different fuels and extend the life of certain units. Certain portfolios also test the effect of applying a minimum renewable energy target of 50%.

Table 2: Energy Mix Portfolios Explored

Portfolio	Description
P2L	Light Fuel Oil
P2F	Heavy (Intermediate) Fuel Oil
P2LL	Light Fuel Oil with Engine Upgrade
P2LM	Methanol with Engine Upgrade
P2N	Liquid Natural Gas with Engine Upgrade
P4N	Liquid Natural Gas with Engine Upgrade and at least 50% renewables generation

Across portfolios, the modelling allowed the system to add different types of new resources as needed, including renewable generation and energy storage. The resource options considered include the following detailed in Table 3.

Table 3: New Technology Modelling Constraints

Technology	Capacity Limit (MW_{AC})	Earliest Commissioning Date
Offshore Wind	60	2032
Onshore Solar	16 (10 + 6 existing)	ASAP
Floating Solar	80	2032
Wave Energy	10	2045
BESS	No Cap	ASAP

Each portfolio was evaluated using a consistent set of metrics to allow an apples-to-apples comparison. The key evaluation areas include customer costs over time, total emissions and renewable energy share, and reliability (i.e. whether the system is expected to have enough capacity to meet demand under many possible operating conditions, including equipment outages and weather variability). Portfolios were also compared on broader practicality considerations such as the ability to maintain adequate operating reserves and resource diversity.

The purpose of this analysis is to identify a recommended path forward that best balances affordability, reliability, and sustainability, while preserving the flexibility to adjust as conditions change (for example, if technology costs shift, project timelines change, or fuel prices evolve).

Results are summarised using a scorecard that compares portfolios across the key objectives and metrics described in Section 3.

5.2 Using less electricity first (Efficiency and Demand Response)

The most cost-effective and environmentally sustainable way to meet Bermuda's energy needs is to use less electricity. These measures reduce customer bills, lower peak demand, and delay the need for new generation. The IRP evaluates a range of demand-side options, including:

- Efficient cooling and appliances that reduce overall consumption
- Building shell improvements such as insulation, window upgrades, and sealing gaps and cracks

- Modern planning and building codes that improve long-term energy performance in new construction and major renovations
- Solar thermal water heating, which reduces electricity use for domestic hot water
- Efficient pool pumps and water pumps, including variable-speed motors
- Timers and smart controls that shift operation of pumps, water heaters, and other equipment to off-peak periods
- Demand response programs that encourage customers to reduce or shift usage during peak hours

5.3 Producing clean electricity (Solar, Wind)

Renewable energy reduces Bermuda's reliance on imported fuels and has the potential to lower long-term operating costs. The IRP evaluates multiple clean-energy options, including:

5.3.1 Behind-the-Meter Solar

Customer-sited solar systems, including rooftop and ground-mounted installations, are treated as behind-the-meter because they sit on the customer's premises and operate on the customer's side of the meter. These systems reduce the customer's net demand and may export excess energy to the grid when production exceeds onsite use. BTMS forms part of the distributed generation and broader distributed energy resource portfolio. BTMS is modelled as a demand reduction for future generation planning, however it's contribution to the Renewable Energy Target (RET) is captured.

5.3.2 Utility-scale solar

Utility-scale solar includes any solar installation that meets the bulk-generation licensing threshold (500kW or greater). These projects may be on-shore ground-mounted arrays, floating solar installations, or large rooftop systems that exceed the threshold. Utility-scale solar supplies energy directly to Bermuda's electricity system and can deliver clean energy at lower cost due to economies of scale, helping to reduce long-term reliance on imported fuels.

5.3.3 Offshore wind

Offshore wind may be a good long-term option for Bermuda. Wind speeds offshore are generally stronger and more consistent than on land, which means offshore wind could complement solar generation by producing energy during periods when solar output is lower. The offshore wind procurement process will seek to determine whether offshore wind is a cost-effective and technically viable resource for Bermuda. Including offshore wind in the resource assessment helps keep the system flexible as technology evolves.

5.3.4 Wave Energy

Wave energy has been included in this IRP as a potential long-term renewable resource that could become relevant to Bermuda over time. For modelling purposes, cost and performance assumptions for wave energy are based on early-stage commercial projects. Future costs are projected using learning rates to reflect uncertainty as the technology matures. At present, wave energy is not being adopted due to both technical challenges, including durability and maintenance in harsh marine environments, and economic factors, including relatively high capital costs and limited operating experience.

5.4 Role of energy storage

Battery storage is an important resource for maintaining a reliable and flexible electricity system. Storage can hold excess solar generation during the day and release it later when demand is higher or when renewable output is lower. This can reduce reliance on imported fuels and helps the system make better use of clean energy.

Storage also provides several grid-support services, including frequency and voltage support, reserves, and short-duration backup during system disturbances. These capabilities make storage a useful complement to renewable energy and an important tool for managing periods of high demand.

The IRP evaluates storage for both its capacity value, which reflects its contribution to meeting reliability requirements, and its energy value, which reflects its ability to shift renewable generation to times when it is most needed.

5.5 Role of dispatchable generation

Dispatchable generation refers to power plants that can be started and stopped as needed, or ramped up and ramped down to match changes in electricity demand and renewable energy output. These resources play an important role in keeping Bermuda's electricity system balanced, especially at times when renewable output is low or when electricity demand is high. They help ensure that power is available constantly throughout the year and support the system during unexpected events or equipment failures.

As Bermuda adds more renewable energy and battery storage, dispatchable generation continues to provide important balancing and backup services. Unlike "dispatchable solar" or hybrid solar-plus-storage, which are limited by sunlight and battery duration, conventional dispatchable units can operate whenever needed and for as long as required. This makes them a key part of maintaining system stability as the resource mix evolves.

The IRP evaluates dispatchable resources for their ability to meet reliability needs, respond quickly to changes in demand, and operate efficiently alongside cleaner technologies. The plan also considers options such as efficiency upgrades, cleaner fuels, and new technologies that can help reduce emissions over time. Detailed assumptions and modelling inputs for dispatchable generation are provided in Appendices D.

6 How Different Futures Were Evaluated

Bermuda has limited-to-no impact on global events and little control over the global market forces that influence the costs incurred to support the deployment of new resources, fuel, etc. To address this systemic risk, the 2026 IRP incorporates a combination of portfolio diversification and scenario planning strategies to compare future planning decisions across a range of macroeconomic changes on a global scale.

6.1 Why multiple portfolios were studied?

Multiple portfolios were studied to capture a range of future conditions and demonstrate that there is no single obvious path to meet all of Bermuda's energy goals at once. The IRP had to test different combinations of fuel choices, renewable energy, storage, and upgrades to existing generators to understand the trade-offs between affordability, reliability, sustainability, and practical execution. For example, some portfolios were designed to minimise cost, while others were designed to achieve higher amounts of renewable energy. Studying several portfolios also helped show how different choices perform under Bermuda's unique island conditions, including limited land, dependence on imported fuels, the need for reserve capacity, and uncertainty about future technology costs and fuel prices. In short, looking at multiple portfolios made it possible to compare realistic pathways side by side and identify the option that best balances customer cost, system reliability, and long-term decarbonisation goals. Table 4summarizes the strategies and conditions assumed across the seven portfolios developed for the 2026 IRP.

Table 4: Portfolio Matrix

		Stay the Course	Economic	Forced 50% RET by 2035
Fuel Strategies	Current fuel strategy	P1	P2F	-
	Switch to LFO with a 10-year Life Cycle Extension	-	P2L	-
	Switch to LFO with a 30-year Life Cycle Upgrade	-	P2LL	-
	Switch to Methanol with a 30-year Life Cycle Upgrade	-	P2LM	-
	Switch to LNG with a 30-year Life Cycle Upgrade	-	P2N	P4N

6.2 What scenarios represent

Scenarios represent different possible future conditions that Bermuda could face over the life of the plan. These can be characterized as outcomes that BELCO does not have direct control over. They are not predictions; they are tools for testing how well each portfolio will perform if important outside factors change. For example, the IRP looked at situations where fuel prices are higher than expected or where clean energy technologies become cheaper and improve more quickly. In simple terms, scenarios help answer the question: if the world changes, will this plan still work well for Bermuda? By comparing its portfolios across scenarios, BELCO can assess the durability, affordability, and reliability of each plan against changes to broader market conditions and understand which portfolios are more exposed to external risk.

The future conditions included high commodity prices (HCP) and technology driven decarbonisation (TDD). Scenario definitions and assumptions are detailed in Appendix F.

Table 5: Scenarios Sensitivity Matrix of Future Variations

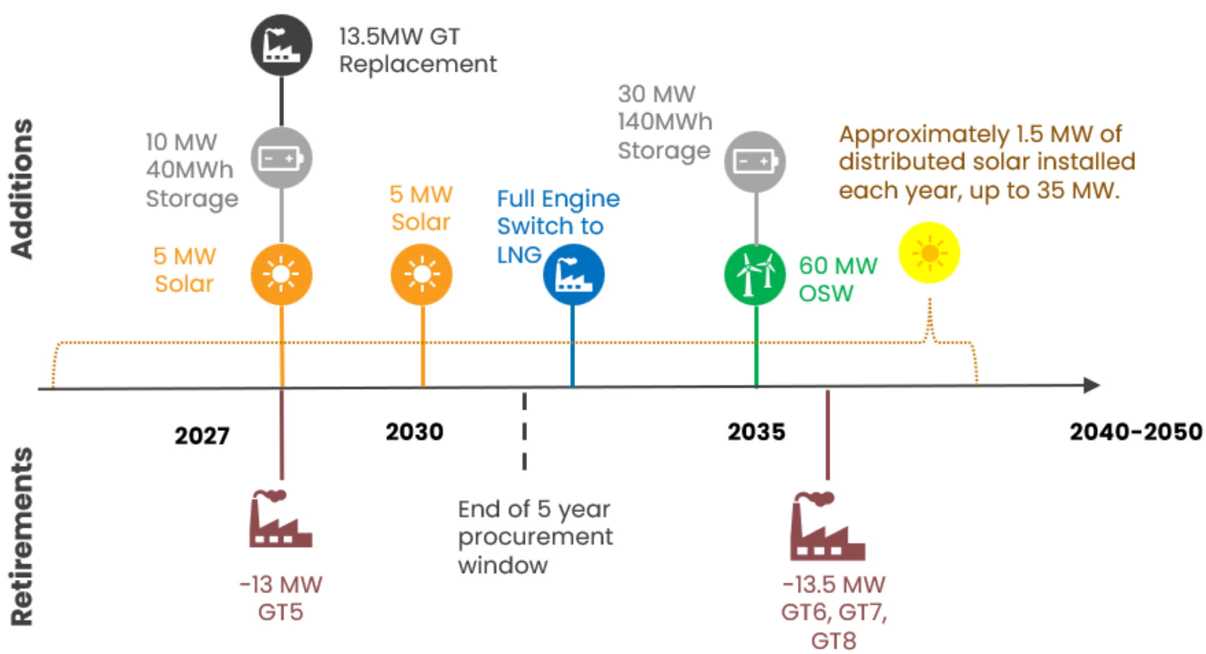
Scenario Concept	REF	HCP	TDD
Technology Costs	Base	Base	Low
Fuel Prices	Base	High	Low
Macro Load Growth	Base	Low	Base
Demand-Side Management	Base	High	Low
EV Penetration	Low	Base	High
Distributed Solar Penetration	Base	High	Base

7 The Recommended Path Forward (Preferred Portfolio)

The recommended path forward is to grow behind-the-meter solar to 35MW, install 10MW of bulk solar, deploy 60MW of wind energy, supported by 40MW of additional storage and convert the fuel supply to liquid natural gas by 2035.

This preferred portfolio, denoted as P4N, meets Bermuda's future electricity needs by prioritising affordability, maintaining reliability, and balancing sustainability. It combines renewable generation, battery storage, and firm generation capacity to maintain a reliable electricity system while managing costs and reducing emissions.

Figure 6: Preferred Portfolio, P4N, Build Out Plan

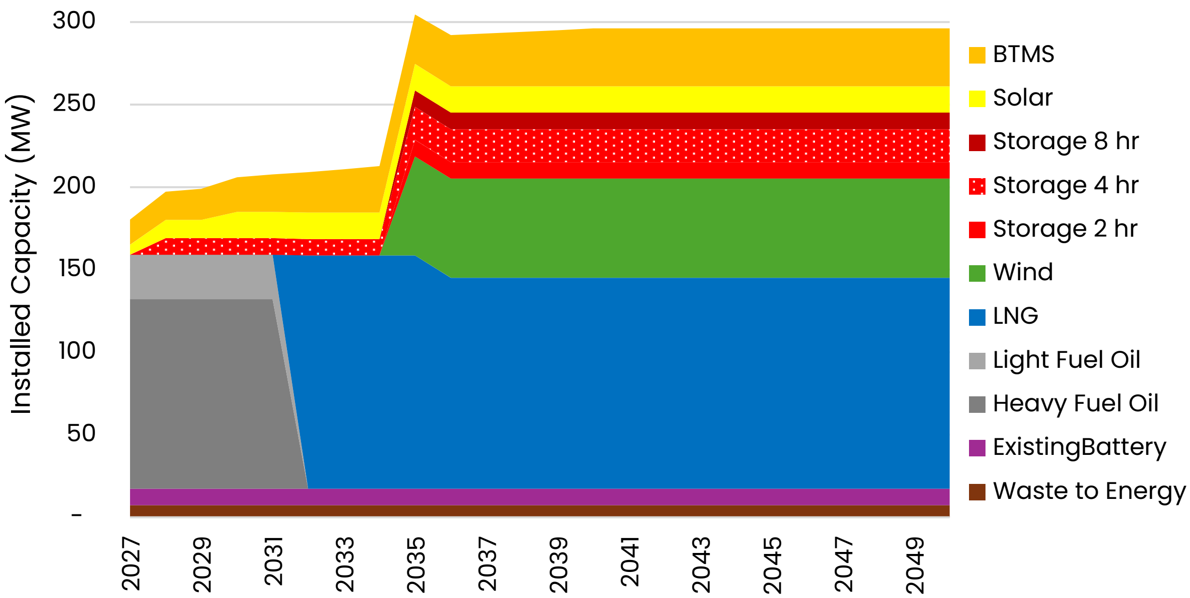


7.1 Technology Mix of the Preferred Portfolio

The total installed capacity (MW) of the various technologies deployed in P4N are displayed in Figure 7. There are no additions or retirements between 2040 and 2050.

The installed capacity increases from 178MW in 2027 to 311MW in 2035.

Figure 7: Installed Capacity Over Time for the Preferred Portfolio, P4N



7.1.1 BTMS Growth

Behind-the-meter solar is expected to grow to $35MW_{AC}$ ($42MW_{DC}$) and contribute toward fuel savings and emission reductions. Virtual power plants (VPPs) including distributed solar, batteries and bidirectional EVs, are rapidly evolving and will soon be able to contribute more services to the grid, provided they are regulated to meet the grid requirements for parallel operation.

7.1.2 Bulk Generation Solar

Bulk generation solar is hoped to grow an additional $10MW_{AC}$ and contribute toward fuel savings and emission reductions. Land constraints are the biggest challenge in Bermuda that requires approximately 30 acres for an additional $10MW_{AC}$ of bulk solar. The cost of land needs to be carefully managed, or project costs may be prohibitive and not lead to greater affordability. Floating solar is rapidly developing in the nearshore environment and is a likely contender to future energy needs and should be also considered as a bulk generation solar option.

7.1.3 Wind Energy

A project for fixed offshore wind of 60MW has been identified as a potential for Bermuda's energy needs. Offshore wind energy is less variable than solar energy but still is likely to produce less energy in low wind periods in the summer. Resiliency to hurricane force winds must be demonstrated at the design stage.

7.1.4 Energy Storage Requirements

Energy storage 40MW (180MWh) is required to provide frequency support, energy shifting and other grid services to maintain short term stability. Analysis demonstrates that battery storage alone cannot economically meet extended periods of evening demand at the scale required for system reliability. Until low-cost seasonal storage becomes available commercially, dispatchable generation continues to play an essential role in maintaining system stability. This is particularly important for Bermuda's isolated electricity system, where there is no ability to rely on external networks during periods of low renewable output.

7.1.5 BELCO Engines & Fuel Choice

The Preferred Portfolio includes targeted lifecycle upgrades to BELCO's existing engine fleet. These generating units are well understood, proven in operation, and suited to the needs of the system. Extending their useful life provides a reliable source of firm capacity while avoiding the cost of near-term full replacement. This approach reduces the risk of unnecessary cost increases for customers while maintaining system performance. Portfolio P4N consists of a transition to LNG from heavy fuel oil in 2032.

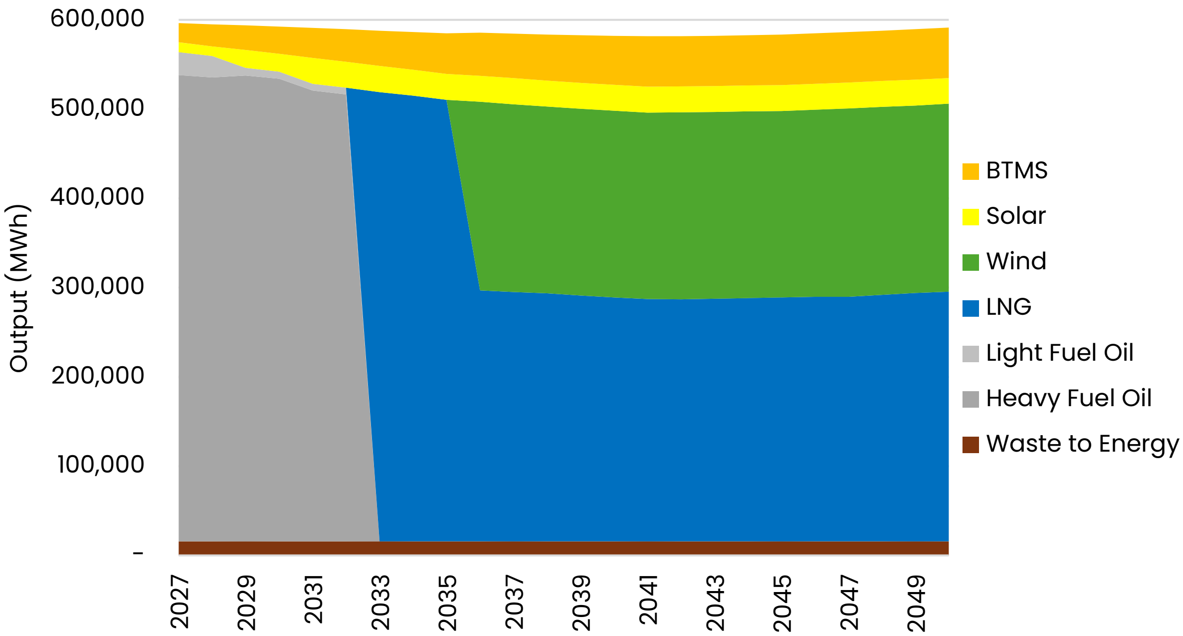
7.1.6 Waste-to-Energy

The 7.3 MW Tynes Bay WTE facility is assumed to continue to provide capacity throughout the planning horizon.

7.2 P4N Energy Contributions

As depicted in Figure 8, solar and wind energy reduce reliance on imported fuels and lower emissions. At the same time, firm generation capacity remains necessary for reliability, especially during periods when renewable output is low.

Figure 8: Resource Contributions to Bermuda's Electricity Demand



This mix reflects the value of LNG in providing reliable and comparatively economic firm supply, the value of renewables in lowering emissions and reducing fuel dependence, and the value of flexibility in allowing Bermuda to adapt future procurement decisions as technologies mature and market conditions change.

7.3 Why this portfolio was selected?

Portfolio P4N was selected because it is the most affordable, provides adequate resiliency and reliability whilst increasing renewable generation to above 50% on island.

P4N realises the value of LNG before it is too late, by lowering the cost of firm supply relative to oil-based pathways. Offshore wind and solar reduce emissions and preserve flexibility by avoiding over-commitment to a single technology or rigid long-term assumptions. That combination makes P4N the preferred pathway for Bermuda under current planning assumptions.

The selection of Portfolio P4N aligns with the draft 2026 National Electricity Sector Policy (NESP), which places affordability, reliability, and equity at the centre of electricity sector planning. The draft policy deliberately moves away from prescriptive generation targets and instead provides strategic direction for the Integrated Resource Plan to identify pragmatic, cost-effective pathways that reflect Bermuda's physical, economic, and system constraints. Portfolio P4N is consistent with this approach, as it does not rely on a single technology outcome but reflects a balanced, technology-agnostic mix that can adapt over time as conditions change.

Figure 9: Comparison of TOTEX and Renewable Energy Generation in 2035 for all Portfolios

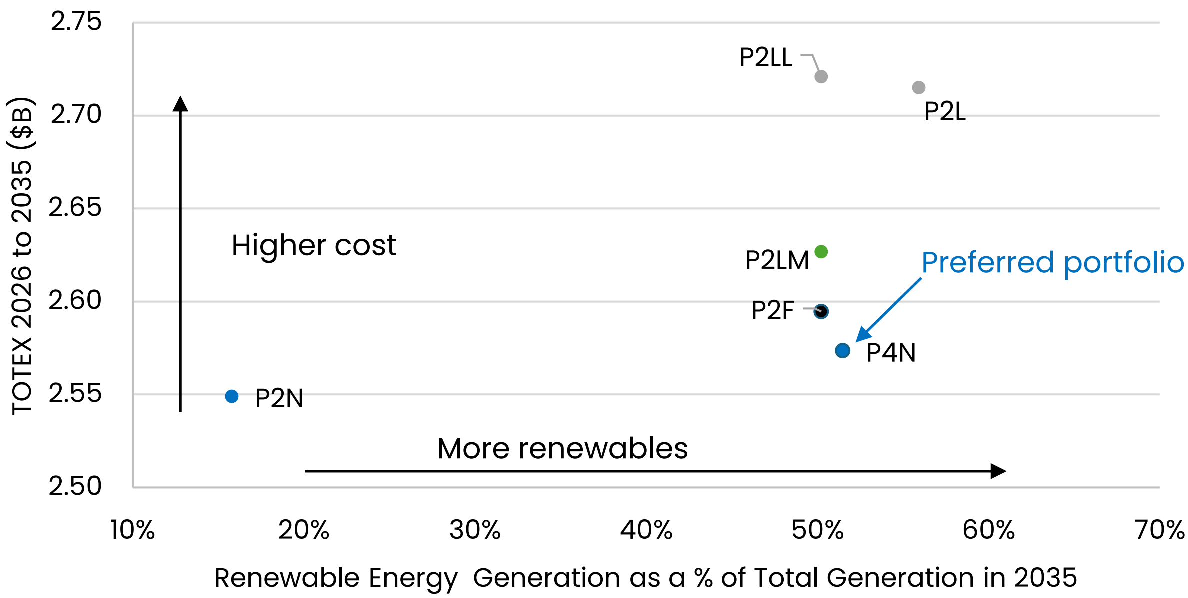


Table 6: Results Summary of each Portfolio

Portfolio	**Result Summary**
P2F	High-rate increases, with long term reliability concerns due to lack of firm capacity demonstrated by higher than acceptable loss of load probability, leading to the potential for further investment. Meets all renewable generation targets.
P2L	High-rate increases, with long term reliability concerns due to lack of firm capacity demonstrated by higher than acceptable loss of load probability, leading to the potential for further investment. Meets all renewable generation targets.
P2LL	Moderate rate increases, firm capacity maintained. Meets all renewable generation targets and reliability standards.
P2N	Most affordable but does not meet 35% renewable energy generation target by 2040 as outlined in draft NESP 2026.
P4N	Preferred Portfolio, second most affordable and meets all renewable generation targets and reliability standards.
P2LM	Methanol is maturing in the power generation market and warrants further investigation as it demonstrates a lower cost than LFO options.

The installed capacity and energy outputs of each portfolio is presented in APPENDIX G - Portfolio Results.

7.4 Scorecard

The scorecard defined in the RA guidance is presented below in Table 7, Table 8 and Table 9.

Table 7: 2035 Scorecard with Key Performance Indicators

Portfolio	Total Expenditure ($ Billions)	average annual rate increase until 2035 (%)	GHG Emission Reductions (%)	Renewable Energy Generation (%)	Operation Risk (%)	Resource Diversity (HHI)	Max LOLP (%)
P2F	2.59	1.09%	49%	50%	50%	5,259	0.049%
P2L	2.71	1.65%	58%	56%	50%	5,342	0.036%
P2LL	2.72	1.43%	51%	50%	5%	7,068	0.049%
P2N	2.55	0.65%	37%	16%	5%	7,065	0.022%
P4N	**2.57**	**1.09%**	**64%**	**51%**	**5%**	**5,336**	**0.016%**
P2LM	2.63	0.83%	55%	50%	8%	6,017	0.049%

Table 8: 2040 Scorecard with Key Performance Indicators

Portfolio	Total Expenditure ($ Billions)	average annual rate increase until 2040 (%)	GHG Emission Reductions (%)	Renewable Energy Generation (%)	Operation Risk (%)	Resource Diversity (HHI)	Max LOLP (%)
P2F	4.24	1.36%	52%	53%	55%	3,555	0.049%
P2L	4.42	1.88%	69%	67%	55%	3,385	0.036%
P2LL	4.42	1.54%	66%	65%	10%	3,723	0.049%
P2N	4.08	0.73%	38%	17%	5%	4,288	0.022%
P4N	**4.16**	**0.83%**	**65%**	**53%**	**10%**	**5,178**	**0.016%**
P2LM	4.22	1.20%	68%	65%	10%	3,723	0.049%

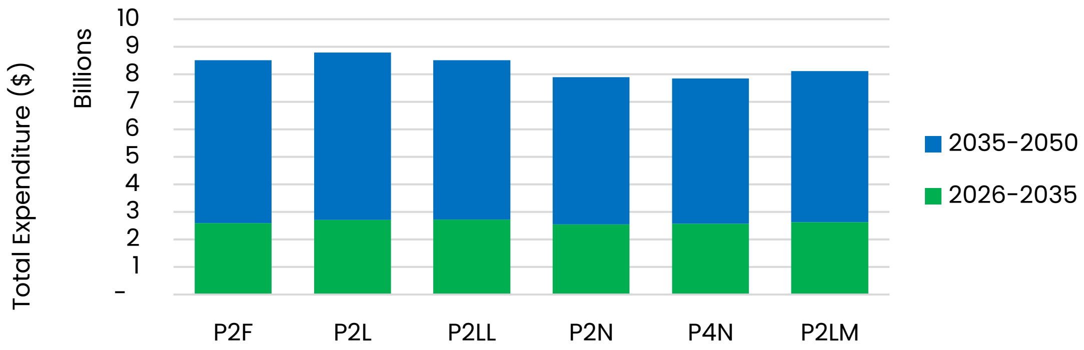
Table 9: 2050 Scorecard with Key Performance Indicators

Portfolio	Total Expenditure ($ Billions)	average annual rate increase until 2050 (%)	GHG Emission Reductions (%)	Renewable Energy Generation (%)	Operation Risk (%)	Resource Diversity (HHI)	Max LOLP (%)
P2F	8.51	1.32%	48%	51%	60%	2,055	0.068%
P2L	8.79	1.43%	71%	71%	60%	2,060	0.036%
P2LL	8.51	1.14%	73%	73%	10%	3,064	0.049%
P2N	7.89	0.53%	64%	52%	10%	5,178	0.022%
P4N	**7.85**	**0.56%**	**64%**	**52%**	**10%**	**5,178**	**0.016%**
P2LM	8.11	0.94%	75%	73%	15%	3,064	0.049%

7.4.1 Expected impacts on customer bills, reliability and emissions

Under Portfolio P4N, expected customer and environmental outcomes are shaped by the combined contribution of LNG, renewables, and flexibility. LNG improves the economics of firm supply and helps manage rate pressure, renewables reduce fuel consumption and emissions, and the portfolio's balanced structure helps preserve reliability as the system changes over time.

Figure 10: Comparison of TOTEX for each Portfolio in 2035 and 2050

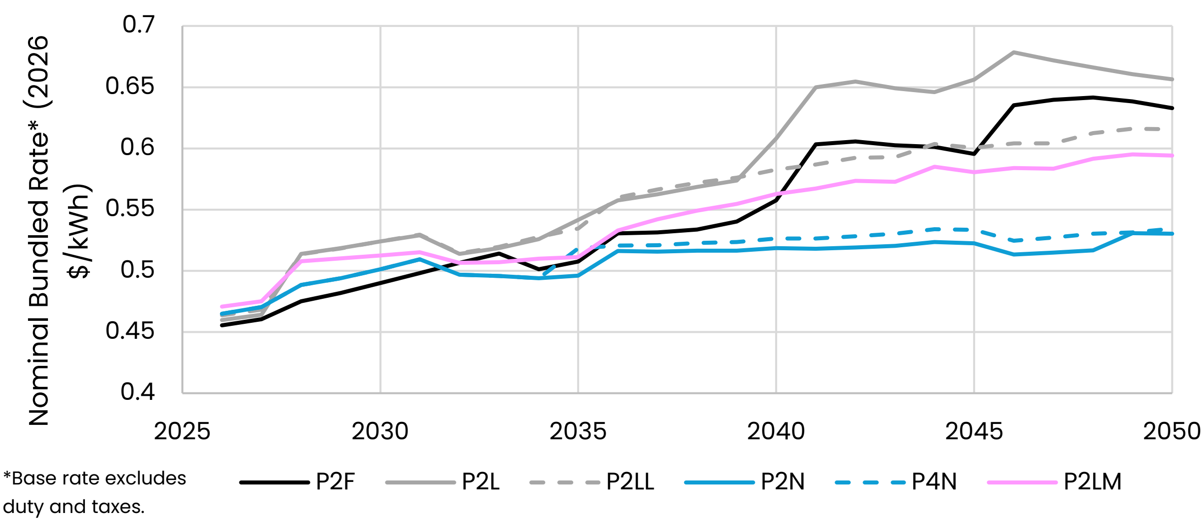


7.4.2 Customer Bills

Adopting a resource mix with a greater share of renewables, alongside switching to LNG for remaining firm capacity, is anticipated to stabilize electricity bills over time. The extent of bill reductions or increases will depend on actual performance, fuel prices, and technology costs. Future bill impacts will be subject to further analysis and refinement, in conjunction with energy project developments.

LNG infrastructure costs are recovered gradually over time through fuel charges, which helps avoid sharp increases in electricity bills.

Figure 11: Bundled Rate Prediction in Nominal Terms



The average cost to customers is expected to increase under all portfolios as illustrated in Figure 11 and Table 10.

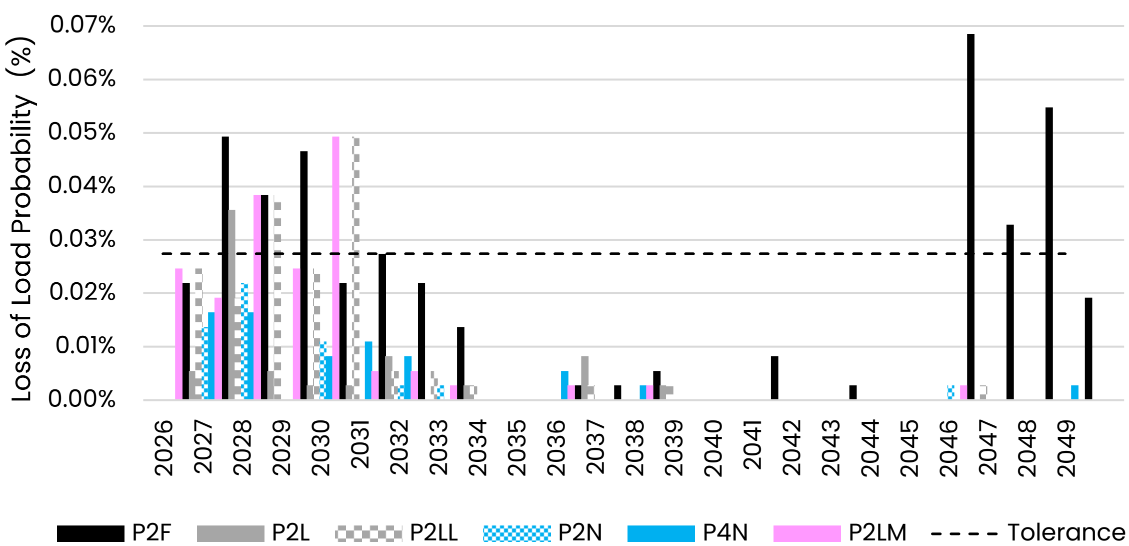
Table 10: Average Cost to Customers by 2035 and 2050

Portfolio	Average Cost to Consumers			
	% rate growth from 2026 to 2035	% rate growth from 2026 to 2050	average annual rate increase until 2035 (%)	average annual rate increase until 2050 (%)
P2F	11%	39%	1.09%	1.32%
P2L	18%	43%	1.65%	1.43%
P2LL	15%	33%	1.43%	1.14%
P2N	7%	14%	0.65%	0.53%
P4N	11%	15%	1.09%	0.56%
P2LM	9%	26%	0.83%	0.94%

7.4.3 System Reliability

System reliability is maintained throughout the transition. The modelling indicates that the P4N portfolio meets established reliability standards, with sufficient dispatchable capacity, storage, and reserves to manage variability from renewable resources and changes in demand. From a customer perspective, this means that the transition to cleaner energy does not compromise the security of electricity supply. Portfolios that exceed the loss-of-load probability threshold shown below in Figure 12 are likely to require additional investment to meet reliability requirements, further increasing costs in portfolios that are already more expensive.

Figure 12: LOLP Results for each Portfolio



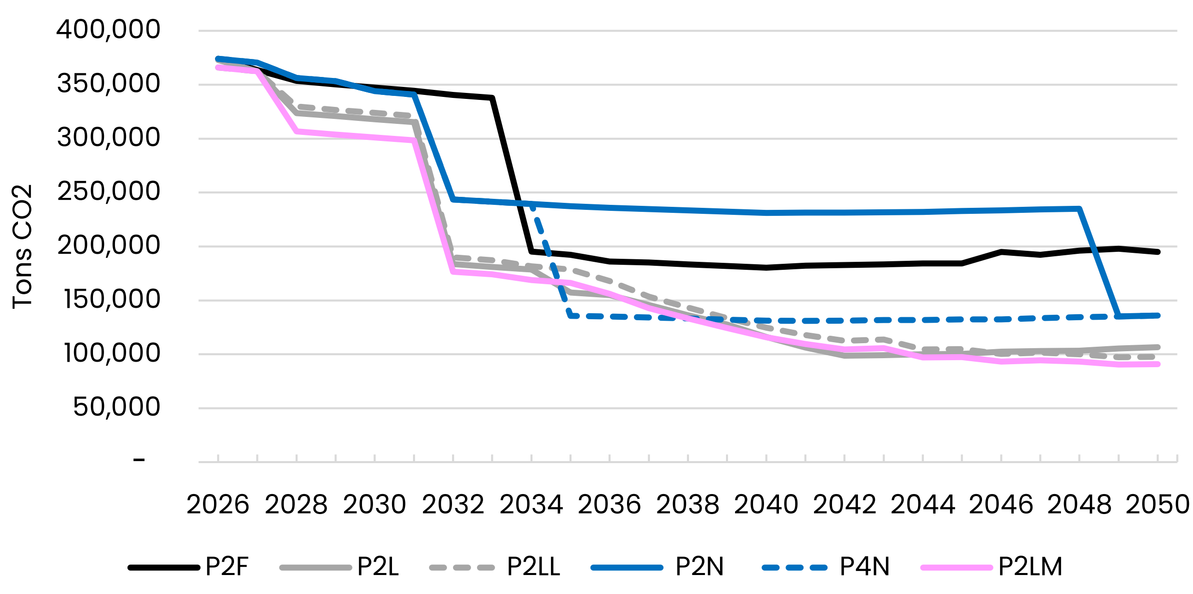
7.4.4 Carbon Emissions & Renewable Generation

Increasing renewable generation and transitioning firm capacity to a cleaner-burning fuel (LNG) is expected to contribute to a steady reduction in carbon emissions from Bermuda's electricity sector. The pace and scale of these reductions will be influenced by the speed of new resource deployment and ongoing market developments. From an environmental standpoint, the P4N portfolio achieves a renewable energy share of approximately 52% by 2050. This level of renewable penetration delivers meaningful emissions reductions compared to today's system while remaining cost-effective. Whilst P2N is affordable, it does not meet the draft NESP 2026 renewable energy generation targets (35%) set for 2040.

Table 11: Carbon Emissions and Renewable Generation of each Portfolio

Portfolios	Total Emissions (Tonnes CO_{2e})	Renewable Generation by 2035	Renewable Generation by 2040	Renewable Generation by 2050
P2F	6,009,071	50%	53%	51%
P2L	4,420,591	56%	67%	71%
P2LL	4,540,295	50%	65%	73%
P2N	6,401,397	16%	17%	52%
P4N	4,994,476	51%	53%	52%
P2LM	4,222,474	50%	65%	51%

Figure 13: Total Emissions for each Portfolio



7.4.5 Operational Risks

The following operations risks have been estimated for each portfolio.

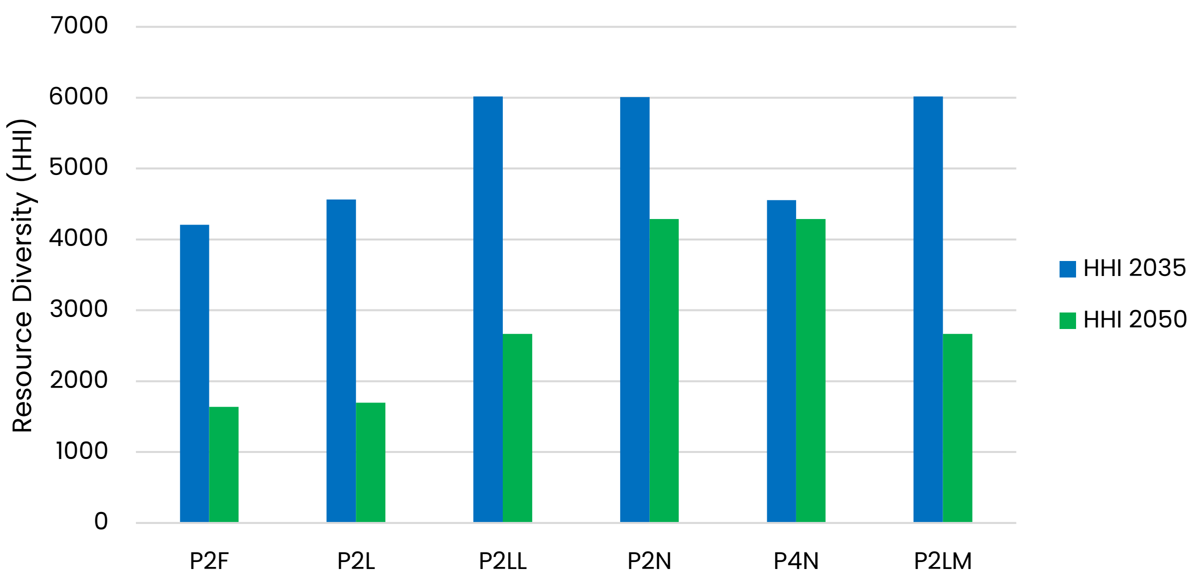
Table 12: Operational Risks for 2035 and 2050

Portfolio	Operational Risks	2035 Operational Risks (%)	2050 Operational Risks (%)
P2F	50% of firm capacity retired before end of planning window. HFO operations subject to soot fallout. OSW will create operational challenges on the network with large fluctuations in output without adequate energy storage and auxiliary services.	50%	60%
P2L	50% of firm capacity retired before end of planning window. OSW will create operational challenges on the network with large fluctuations in output without adequate energy storage and auxiliary services.	50%	60%
P2LL	LFO is high cost, operation limited to one fuel. OSW will create operational challenges on the network with large fluctuations in output without adequate energy storage and auxiliary services.	5%	10%
P2N	Bermuda has limited to no experience in LNG handling.	5%	10%
P4N	Bermuda has limited to no experience in LNG handling. OSW will create operational challenges on the network with large fluctuations in output without adequate energy storage and auxiliary services.	5%	10%
P2LM	Methanol requires double the storage volumetrically to maintain the same fuel reserves on island. LFO provides a secondary fuel option. OSW will create operational challenges on the network with large fluctuations in output without adequate energy storage and auxiliary services.	8%	15%

7.4.6 Resource Diversity

Resource diversity improves across all portfolios between 2035 and 2050. This is measured using the Herfindahl–Hirschman Index (HHI), where a lower score means the electricity system relies on a broader mix of resources rather than depending too heavily on just a few. In every portfolio, the HHI falls over time, showing that the resource mix becomes more diverse by 2050. This is a positive outcome because a more diverse system is generally more flexible, more resilient, and better able to adapt to future changes.

Figure 14: Resource Diversity (HHI)



7.5 Results Summary

Bermuda's renewable resource options are limited to solar, wind, and wave energy. Among these, onshore solar continues to be identified as the most viable near-term resource due to its comparatively lower cost and feasibility of deployment. Portfolio P4N prioritizes the development of onshore solar while also incorporating additional resources as required to meet reliability and capacity needs.

However, the optimal long-term mix is subject to ongoing evaluation. There are still technical and economic uncertainties related to large-scale adoption of offshore wind and floating solar technologies. The portfolio reflects current knowledge and assumptions but recognizes that further detailed analysis will be needed as these technologies mature and risks become better understood in the Bermuda hurricane region.

Fuel costs are a key driver of electricity prices in Bermuda. For this reason, the Preferred Portfolio does not assume an immediate transition away from the continued use of fuel oils in the near term. Fuel oils remain a proven and reliable baseline fuel for the existing generation fleet.

Maintaining this approach in the short term supports system stability and avoids premature investment decisions.

At the same time, the Preferred Portfolio recognises the importance of evaluating lower-carbon fuel options over the medium term. Liquefied natural gas and methanol are identified as potential alternatives, but no immediate commitment is made to either option. Instead, a structured evaluation process is recommended to assess their suitability.

This evaluation is designed as a staged process, outlined in Section 8.1, and is intended to inform future procurement decisions rather than predetermine outcomes. It will consider key factors such as compatibility with existing assets, fuel supply requirements, infrastructure needs, relative costs, customer impacts, environmental performance, and regulatory considerations. This approach ensures that future decisions are based on robust evidence and reflect the conditions at the time they are made.

In summary, the Preferred Portfolio maintains sufficient firm capacity to reliably meet demand, supports continued integration of renewable energy, and avoids premature investment in new fuel infrastructure. It extends the life of existing generation assets to manage costs in the near term, while establishing a clear process to evaluate lower-carbon fuel options for the future. This approach balances affordability, reliability, and flexibility, and preserves the ability to adapt as technologies, fuel markets, and policy conditions continue to evolve.

8 Risks, Uncertainty, and Flexibility

Future conditions may differ from current expectations. The IRP identifies signposts that would trigger reassessment, such as delays in offshore wind development, significant fuel price changes, or rapid advancements in alternative technologies.

8.1 Key risks and uncertainties

Even the best long-term plan must deal with uncertainty. The IRP identified several key risks that could affect how Bermuda's electricity system develops, including changes in global fuel prices, the future cost and performance of clean energy technologies, delays in permitting or building major projects, and uncertainty about how quickly customers adopt rooftop solar, batteries, or electric vehicles. There are also broader risks, such as supply chain disruptions, changing market conditions, and possible future policy changes. In simple terms, these uncertainties matter because they can affect cost, timing, reliability, and the pace of emissions reduction. That is why the plan was designed not just to choose a preferred path, but also to remain flexible if conditions change.

8.1.1 Importance of flexibility

- Adaptable planning is essential for an island grid because an island system has less room for error and fewer fallback options than an interconnected mainland grid.
- Bermuda cannot import power from neighbouring systems when something fails. If a generator trips or demand spikes, the island must handle it alone.
- Fuel deliveries, spare parts, and major equipment often depend on shipping and external supply chains. Delays can quickly become reliability risks.
- On a smaller grid, the loss of one unit or a change in renewable output can have a much bigger effect on frequency, reserves, and stability.
- Solar, wind, and storage can lower costs and emissions, but they also change net load patterns. Planning must adjust as technology performance, costs, and integration limits evolve.
- EV adoption, behind-the-meter solar, tourism, weather, and economic conditions can all shift load forecasts materially over time.
- Islands have limited space, so if one resource becomes harder to permit or deploy, planners need credible alternatives ready.

8.2 Monitoring progress

Monitoring progress means regularly checking whether the plan is unfolding as expected and whether key assumptions are still valid. In practice, this includes tracking things like electricity demand, fuel prices, renewable project timelines, customer adoption of solar and electric vehicles, system reliability, and the costs of new technologies. By monitoring these signals over time, the IRP can be used to assess whether the preferred path remains appropriate or whether adjustments may be needed. In simple terms, monitoring progress helps turn the IRP from a one-time document into a living plan that can respond to real-world changes.

8.3 Least Regret

A least-regret approach in energy planning means making decisions that work well under a range of future conditions, even if some assumptions change over time. In practice, it means keeping options open, avoiding unnecessary long-term risks, and choosing actions that support affordable electricity while Bermuda's energy system continues to evolve reliably.

A least-regret approach means recognising that Bermuda will continue to need some firm, flexible generation even as renewable energy grows. The analysis shows that renewable energy can make an important and increasing contribution, but on its own it is unlikely to reliably meet all of Bermuda's electricity needs at all times.

In this context, future fuel choices should be viewed as a way to support reliability and complement renewable energy, rather than as a long-term replacement. While fuels can involve risks, such as infrastructure costs or long-term supply commitments, these risks can be reduced through careful planning, flexible contract arrangements, and scalable infrastructure options. Over time, the role of fuel-based generation is expected to change, with these resources used less for producing large amounts of energy and more for providing backup capacity and system stability when needed.

By keeping options open and making decisions in stages, cleaner fuels serve as a practical and flexible part of Bermuda's energy transition, helping to maintain reliable service while enabling continued growth in renewable energy.

9 Implementation Roadmap

This section sets out the practical steps needed to move from planning to delivery. It identifies the near- and medium-term actions that will help Bermuda implement the preferred pathway in a way that remains flexible, transparent, and responsive to changing conditions.

9.1 Immediate actions

The proposed immediate actions focus on procurement and detailed engineering studies for storage resources, replacing aging gas turbine capacity, and launching energy efficiency programs. The TD&R Licensee shall be responsible for procuring the energy storage in the immediate term.

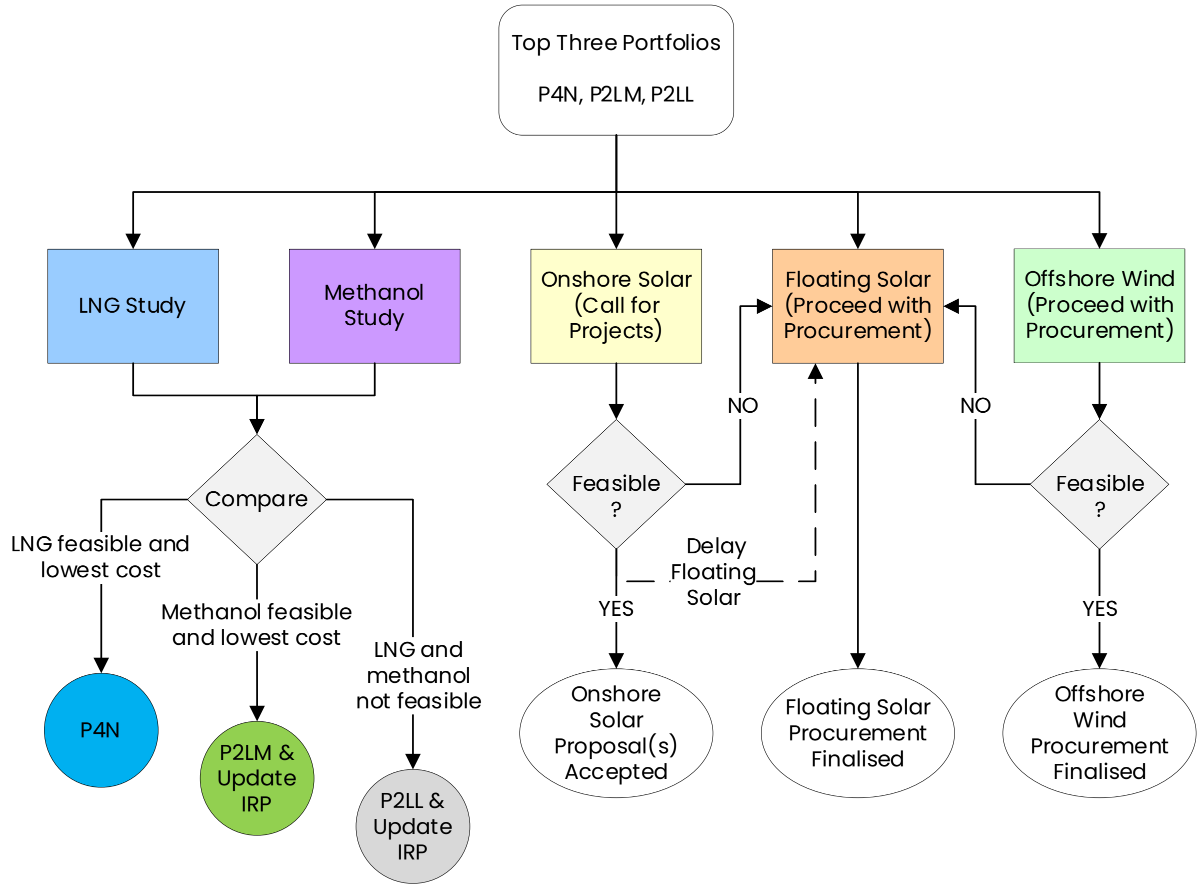
Over the next one to two years, immediate actions will focus on reducing uncertainty around future fuel choices and ensuring that any potential transition is technically feasible, economically prudent, and socially acceptable.

A priority action is to engage an independent third-party advisor to undertake a comprehensive evaluation of liquefied natural gas and methanol as alternative fuel options for Bermuda's electricity system. This assessment will examine technical compatibility with existing and future generation assets, fuel supply security and infrastructure requirements, long-term cost and rate impacts for customers, and environmental considerations, alongside social factors such as public acceptance, siting constraints, and community concerns. This step is particularly important given Bermuda's historical resistance to LNG, despite prior analyses indicating potential cost advantages relative to continued reliance on fuel oil.

The purpose of this work is not to commit to a specific fuel pathway, but to establish a transparent, evidence-based understanding of whether LNG, methanol, or neither option can meet Bermuda's needs for affordability, reliability, and resilience within the island's unique physical and social context. The findings will inform subsequent fuel procurements and future regulatory decisions, while preserving flexibility and avoiding premature or irreversible investment commitments.

The accompanying flow chart in Figure 15 provides a visual overview of these actions, showing the decision pathways and expected timelines for each step.

Figure 15: Implementation Pathway and Decision Tree



9.2 Near-term actions (5-year procurement window)

This section outlines the key steps and priorities for energy resource procurement within the next five years. The purpose is to support timely decision-making and progress towards the preferred portfolio (P4N), ensuring alignment with Bermuda's evolving energy needs and the draft NESP 2026.

The procurement process is guided by a flow chart in Figure 15 that illustrates the sequence of actions, evaluation points, and decision milestones. These steps are designed to facilitate transparent and efficient selection and implementation of new resources.

9.2.1 Summary of Near-Term Actions:

- Initiate procurement for new onshore solar capacity, as identified in Portfolio P4N.
- Complete technical and economic assessments and proceed with procurement for offshore wind and floating solar.
- Monitor ongoing performance of existing assets and adjust resource planning as required.

- Engage stakeholders and the Regulatory Authority to maintain compliance and transparency throughout the procurement process.
- Review and update procurement procedures annually to incorporate market developments and regulatory guidance.
- The TD&R Licensee shall be responsible for procuring the energy storage in the near term.
- More advanced power system studies are required to determine the optimum deployment of technology for frequency and voltage support.

9.2.2 Near Term Signposts and Pivot Strategies

Table 13: Signposts and Pivot Strategies

Signpost	Pivot Strategy
Headwinds against the development of offshore wind projects	Pivot to floating solar
Headwinds against the development of onshore solar projects	Pivot to floating solar
Floating solar decreases in CapEx and/or OpEx	Reevaluate the capacity expansion offering solar at lower costs

9.3 Medium-term planning activities

Medium-term planning activities will focus on translating the outcomes of the near-term fuel evaluations into practical system actions, while continuing to expand renewable energy in a measured and coordinated manner. The findings of the independent assessments described in Section 9.1, will identify LNG, methanol, LFO, or an alternative as the preferred fuel option based on criteria such as technical feasibility, economic, prudent, and social acceptability. The preferred fuel strategy would then be advanced to the next stage of detailed planning and regulatory review. In parallel, the preferred pathway includes upgrades to the existing engine fleet to a modernised platform capable of operating reliably as firm, dispatchable capacity over the long term. These upgrades are intended to preserve system reliability on an isolated grid and ensure that sufficient firm capacity remains available as renewable penetration increases, consistent with the Electricity Act's requirement to maintain safe and reliable service and the draft National Electricity Sector Policy's emphasis on resilience and affordability.

Once the initial tranche of near-term renewable projects has been delivered and operational experience has been gained, the IRP framework calls for a reassessment of further renewable energy potential. This review will consider actual system performance, impacts on reliability and costs, and updated information on technology readiness and customer adoption. The results will inform subsequent IRP updates and future procurement decisions, ensuring that renewable expansion continues only where it remains technically feasible, economically justified, and consistent with Bermuda's long-term policy objectives. The TD&R Licensee shall be responsible for procuring the energy storage in the long-term.

This staged approach preserves flexibility, avoids premature commitments, and remains aligned with the Electricity Act, the National Electricity Sector Policy, and the Regulatory Authority's guidance that the IRP serve as a planning framework rather than an approval of specific projects or fuels.

9.4 Stakeholder and regulatory coordination

Effective delivery of an approved Integrated Resource Plan depends on continued coordination between Government, the Regulatory Authority, and the electricity sector, with the shared objective of identifying the most affordable, reliable, and practical path forward for Bermuda. The Electricity Act establishes a framework in which policy direction, regulatory oversight, and utility planning each play distinct but complementary roles, requiring ongoing engagement and transparency as decisions progress from planning to implementation. The draft National Electricity Sector Policy 2026 provides an important forum for aligning these roles by setting clear, high-level priorities for affordability, reliability, resilience, and equity, while avoiding prescriptive outcomes and allowing evidence-based decision-making to guide resource choices.

Consistent with the Regulatory Authority's IRP guidance, BELCO will continue to engage proactively with the Regulatory Authority and relevant Government bodies to ensure that planning assumptions, evaluation methods, and proposed actions remain transparent, well-justified, and responsive to public input. Stakeholder engagement is particularly important in areas where there are differing views, such as fuel choice and new infrastructure, and where experience has shown that public confidence depends on clear communication of costs, risks, and benefits.

While differing perspectives are expected, the IRP framework emphasises that decisions should be grounded in robust data, independent analysis, and demonstrated system need, rather than driven by short-term sentiment. Through structured coordination and open communication, this approach supports informed decision-making that serves the long-term interests of Bermuda's customers and the wider community.

10 Key Takeaways and Conclusion

This IRP presents a balanced and flexible pathway that significantly reduces emissions, preserves reliability, and manages long-term costs for customers.

The analysis indicates that Portfolio P4N is the preferred pathway for Bermuda. By combining LNG for firm dispatchable generation with renewable additions and storage, P4N provides a practical route to reduce emissions, maintain reliability, and manage long-term costs for customers. The plan is intentionally flexible so that future procurement and investment decisions can adjust as technologies, market conditions, and policy priorities evolve.

10.1 Summary of benefits

The analysis undertaken for this IRP indicates that the P4N pathway is the preferred portfolio because it best combines three sources of value. First, LNG provides dependable, dispatchable generation that supports affordability and system reliability. Second, renewables—principally offshore wind and onshore solar—reduce emissions and fuel exposure over time. Third, the portfolio preserves flexibility, allowing Bermuda to adapt future decisions as fuel economics, technology performance, and implementation realities change. In concrete terms, P4N consists of LNG conversion for firm generation, 60 MW of offshore wind, 10 MW of onshore solar, and battery storage.

The use of LNG within P4N allows Bermuda to achieve near-term emissions reductions without compromising reliability or placing undue reliance on technologies that remain constrained by land availability, system integration limits, or delivery risk. It also supports fuel diversification and reduces exposure to the volatility associated with a single fuel source, consistent with the Regulatory Authority's guidance on realism and risk management. Importantly, the LNG pathway is designed to preserve flexibility by avoiding irreversible investment decisions and maintaining optionality for future low-carbon and zero-carbon resources as they become technically and economically viable. This approach aligns with the draft National Electricity Sector Policy's emphasis on affordability, resilience, and a gradual, managed transition to a lower-carbon electricity system.

10.2 What success looks like

Successful implementation of this IRP would result in an electricity system that continues to deliver high levels of reliability and service quality, while gradually reducing emissions and fuel risk over time. Customers would see a system that remains resilient during extreme weather events and supply disruptions, supported by adequate dispatchable capacity and prudent reserve margins.

Over the planning horizon, success would also be reflected in steady progress toward policy goals, including lower average emissions intensity, increased operational flexibility, and the ability to integrate additional clean energy resources as they become feasible. Importantly, success is not defined by a single project or technology, but by the system's ability to adapt to changing conditions without placing undue cost or reliability burdens on customers. This outcome-based framing is consistent with the NESP's emphasis on resilience, equity, and affordability, as well as the Authority's guidance on managing uncertainty.

10.3 Commitment to updates

This IRP is not a static plan. It is intended to be reviewed and updated as required under the Electricity Act 2016 to reflect new information, changing policy direction, technology developments, and observed system performance. The assumptions, pathways, and timing presented here are based on the best information available at the time of analysis, including the Regulatory Authority's guidance on resource caps, timelines, and modelling inputs.

Future updates will allow the plan to respond to material changes such as shifts in fuel markets, advancements in renewable or storage technologies, updated demand trends, or revised policy objectives. This commitment to periodic review ensures that Bermuda's electricity system planning remains transparent, evidence-based, and aligned with the public interest over time.

APPENDIX A - MODELLING FRAMEWORK AND SOFTWARE

A.1 Modelling Setup and Process

Aurora is a commercially available third-party software used to evaluate alternative supply- and demand-side portfolios. Aurora is a reputable tool that is used by utilities internationally to assess the trade-offs between resource options. At Aurora's core is a chronological production cost dispatch engine that evaluates hourly least cost dispatch for a portfolio of resources against a stated demand. Aurora can also identify the least cost optimal schedule of plant retirements and additions to meet a required reserve margin target or renewable targets, subject to a set of operating constraints.

The portfolios were set up within Aurora with all owned and contracted resources. Aurora simulates the hourly chronological dispatch of energy assets and calculates all variable costs associated with the dispatch of owned resources (e.g., fuel, variable operating and maintenance, startup, and emission costs). The Aurora model was run hourly from 2026 to 2050 to evaluate all portfolios against all scenarios.

A.1.1 Supply Resources

In addition to the owned and contracted resources in the energy system, several other load-varying resources were included in the model. BTMS was modelled as a distributed generation resource.[1] As BTMS adoption continues to grow, an assessment was conducted on the distribution level to forecast the ultimate capacity and energy generation capability. Scenarios also altered the state of resource penetration. BTMS follows the same production shape as the other solar resources that are included in Section E.1. By modelling as a supply-side resource, adjustments to the forecast could be easily integrated into the model.

A.1.2 Demand Resources

Electric vehicle penetration in Bermuda is expected to grow over time. Electric vehicles were modelled as part of the demand. EVs are modelled to include the actual vehicle demand and the charging shape to properly simulate the energy demand on the system. EVs are given a negative capacity value, which simulates a resource drawing load from the grid.

The model was set up to include EE programmes, and BTMS was always considered. The resources were set to "must run" so every dispatch result includes generation or demand from these resources. These programmes include residential lighting, appliances, and commercial HVAC systems, among others. Like BTMS, it is expected that these resources will change over time so modelling them as a supply-side resource allows for easier adjustments.

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[1] As BTMS is not a fungible resource, the projections were modelled as given and not included as part of the capacity expansion, but rather a demand side adjustment.

APPENDIX B - DETAILED LOAD FORECASTS

A primary output of an IRP process is determining the set of demand-side and supply-side resources that are best able to meet the utility's load requirements over time. This section describes Bermuda's load forecast requirements and some of the key uncertainties that could contribute to higher or lower load levels.

The load forecast was developed through a bottom-up approach. Separate forecasts were developed for the number of customers and energy use at each customer group (class) level. The forecasts were aggregated to the system level of total energy sales, total energy requirements, and peak demand. Monthly forecasts were developed using a combination of multivariate regression models and trending techniques.

The TD&R Licensee's 2022 retail energy sales by class are presented in Figure 2. The residential class is the largest with nearly 33,000 customers, comprising 46%of 2022 total retail sales. The Demand metered class comprised roughly 40% of 2022 retail sales but included just over 200 large customers. Smaller businesses are included in the commercial class with over 3,000 businesses that account for 15% of the TD&R Licensee's 2022 retail electric sales. Customers with BTM renewable energy systems and subject to the Feed-In-Tariff are embedded within these three classes for forecasting purposes.

The following appendices detail the data sources, methodologies, and forecast results at a class level and for the total energy system. The forecasts presented here exclude the impacts of BTMS output from customer-owned solar installations (Section: B.6), electric vehicles (Section: B.5.1), and any newly implemented DSM programmes (Section: C.2), which is incorporated separately into the IRP analyses.

B.1 Load Forecast Inputs

To develop an accurate load forecast, extensive data was collected. Historical information was required for weather, gross domestic product (GDP), tourism, actual system energy requirements and peak demand. The following key information for January 2012 to October 2022 was provided:

- The monthly number of customers, energy sales, and revenues by customer class.
- The number of customers and average usage per class – residential, commercial, demand, and customers with DERs.[2]

[2] Customers with DERs were broken down and backed into the main three classes: residential, commercial, and demand.

- Monthly total system energy requirements (including estimated losses, own use, and miscellaneous) and system peak demand including date and hour for January 2012 to September 2022.
- Historical data for the monthly number of BTMS installations and energy impacts from installation.
- Key economic, demographic, and related data, including:
  - Quarterly GDP data from the Department of Statistics under Bermuda's Ministry of Economy and Labour[3] and Moody's Analytics
  - Tourism value index from the Department of Statistics under Bermuda's Ministry of Economy and Labour[3]
  - Population, housing, and related data from Bermuda Census data and related reports from government sources
  - Appliance efficiency information from the U.S. Department of Energy – Energy Information Administration.
- Weather data from Virtual Crossing[4] data source.

B.2 Load Forecast by Class

Each customer class has specific considerations that impact how the load forecast is performed. Detailed information on each class forecast can be found in the following sections.

B.2.1 Residential Class

The residential class includes nearly 33,000 customers. Total sales to the residential class were approximately 239 GWh in 2022, slightly less than the 250 GWh of sales in 2012. Modest growth in the number of residential customers over the past decade has been more than offset by lower electric use per customer, driven by more efficient appliances and lighting along with solar installations by over 900 residential customers as of early 2023.

The residential customer forecast is correlated to Bermuda's population change. Bermuda's population growth has been very modest over the past decade and has now slowed to near zero, as is reflected in the residential customer trends. Bermuda's population is projected to remain flat or decline slightly into the foreseeable future. For this reason, the residential customer forecast remains flat after 2023 but does not decline since it is not anticipated that

[3] https://www.gov.bm/bermuda-economic-statistics
[4] https://www.visualcrossing.com/

any further population decline will lead to a material reduction in the housing stock on the island or the residential customer count.

Average electricity use per residential customer has declined at an average annual rate of 0.7 percent over the past decade, driven by more efficient appliances and homes, the LED lighting transformation, and the installation of solar at over 900 homes. Excluding the estimated impacts of self-consumed (SC) solar, the annual decline would have averaged 0.5 percent. The residential kWh per customer forecast is developed using an econometric model that relates the historical monthly series excluding the impacts of SC solar to the real (inflation-adjusted) price of electricity (a 12-month moving average to smooth volatility), monthly heating degree days, monthly cooling degree days, and an appliance efficiency index. Shift variables are included for selected months, as needed. The resulting forecast of electricity use per customer decreases at an average annual rate of 0.2 percent over the 2023 to 2042 period excluding the impacts of self-consumed solar, which are incorporated separately in the IRP analysis. This decline is primarily driven by continued improvements in home appliances and lighting efficiencies.

The residential electric sales forecast is the product of the customer and average use per customer forecasts. Residential electric sales decrease at an average annual rate of 0.2 percent from 2023 to 2042 excluding the impacts of self-consumed solar, which are incorporated separately in the IRP analysis.

B.2.2 Commercial Class

The TD&R Licensee serves over 3,000 commercial customers, including a wide variety of small to medium-sized businesses and other non-residential accounts. Energy sales to the commercial class have declined over the past decade due to economic factors, EE, and BTMS impacts. The influence of the COVID-19 Pandemic (the Pandemic) on commercial electricity sales is evident in 2020 and 2021, with some rebound in 2022 that is expected to carry into 2023 and 2024 before stabilising.

Excluding BTMS impacts, commercial sales rebound slightly in 2023 and 2024 due to the continued recovery from the Pandemic impacts before remaining flat through the remainder of the forecast horizon, as driven by the flat real GDP forecast.

The number of commercial customers has increased slowly over the past decade, mirroring the residential customer trends. The commercial customer forecast is developed using an econometric model relating the number of customers to real (inflation-adjusted) GDP with a 24-month lag and a tourism output value available from Bermuda statistics. Bermuda's real GDP has shown periods of increases and decreases over the past decade, including the pandemic period, but has not consistently increased nor declined and is therefore left flat in the future. The tourism value index follows the real GDP forecast. The resulting commercial customer forecast provides a flat trajectory over the long term.

Average electric use per commercial customer has declined over the past decade due to slow economic growth, efficiency improvements in commercial lighting and other equipment, and a modest amount of on-site solar installed. The commercial energy use-per-customer forecast uses an econometric model relating average energy use without self-consumed solar impacts to real GDP (a 12-month moving average) and cooling degree days. A shift is incorporated over the key COVID period of March to October 2020 and selected monthly variables are included, as needed, to fit the unique monthly pattern of commercial electric sales. The resulting forecast projects that average energy use excluding SC solar will continue to recover in the early years of the forecasts before stabilizing in the long run, following the flat trajectory of real GDP. The impacts of future self-consumed solar are incorporated separately in the IRP analysis.

The commercial electric sales forecast is the product of the customer and average use per customer forecast. Excluding self-consumed solar impacts, commercial sales rebound slightly in 2023 and 2024 due to the continued recovery from the pandemic impacts before remaining flat through the remainder of the forecast horizon, as driven by the flat real GDP forecast.

B.2.3 Demand Class

The TD&R Licensee serves 210 customers that are metered and billed on peak demand as well as energy consumption. These customers are generally larger than the businesses and other non-residential accounts that are included in the commercial class. This class comprised nearly 40% of the TD&R Licensee's retail electric sales in 2022 with the average annual electric use per customer near one million kWh.

The number of demand metered customers has changed little over the past decade and is expected to remain at the current level throughout the forecast horizon. Excluding BTMS impacts, electric sales increase slightly in the first few years of the forecast due to a recovering economy and then flatten thereafter.

Average electricity uses per demand metered customer has declined over the past decade, driven by economic conditions, efficiency improvements in lighting and other equipment, and some installation of on-site solar. These trends and drivers are like those impacting the commercial class. The forecast of average electric use per customer is developed using an econometric model relating use per customer (without self-consumed solar impacts) to real GDP (a 12-month moving average) and cooling degree days. A shift is incorporated over the key COVID period of March to October 2020 and selected monthly variables are included, as needed. It is noteworthy that these variables are the same as were used in the commercial energy use model, reflecting the similarities in the growth drivers between the two classes. The resulting forecast increases modestly in the early years of the forecast due to continued recovery from the pandemic lows and then flattens following the flat long-term real GDP forecast trajectory.

Total electricity sales to the demand metered class are the product of the customer and energy use per customer forecasts. Excluding self-consumed solar impacts, electric sales increase slightly in the first few years of the forecast due to a recovering economy and then flatten thereafter.

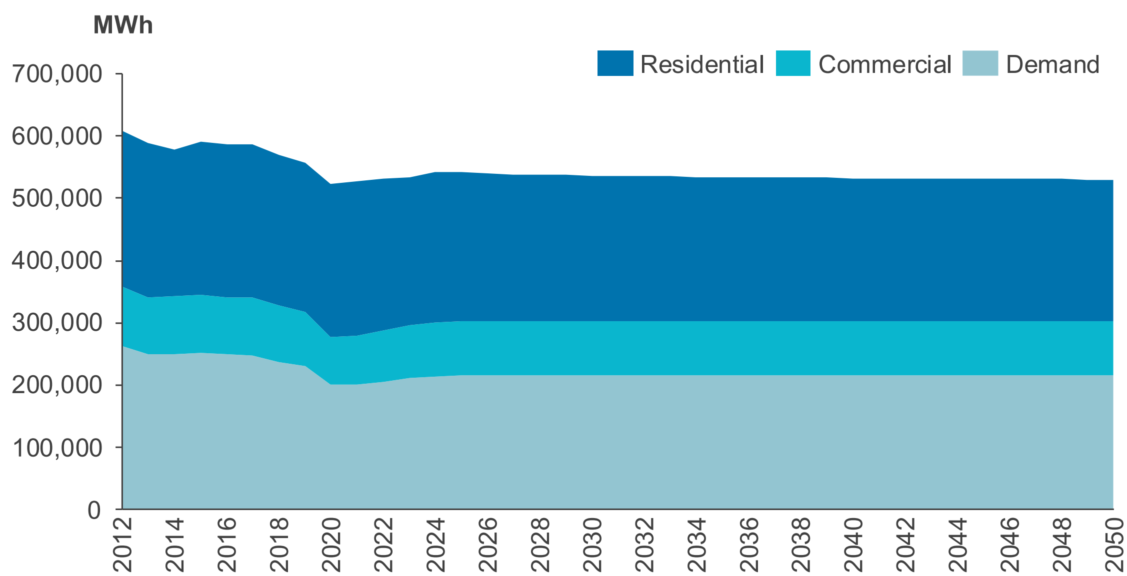
The historical data includes both actual (metered) and an estimate excluding the impacts of self-consumed solar generation.

B.3 Total Energy Sales and Requirements

Total energy sales are the sum of energy sales across the residential, commercial, and demand metered classes. Excluding the impacts of BTMS, total energy sales declined slightly over the forecast period. The residential energy forecast declines due to ongoing efficiency improvements in home appliances and equipment while the commercial and demand metered class forecasts are driven primarily by GDP and are relatively flat after the first few years of recovery. The share of total energy sales to the residential class decreases from 46% in 2022 to 43% by 2042, excluding the impacts of BTMS.

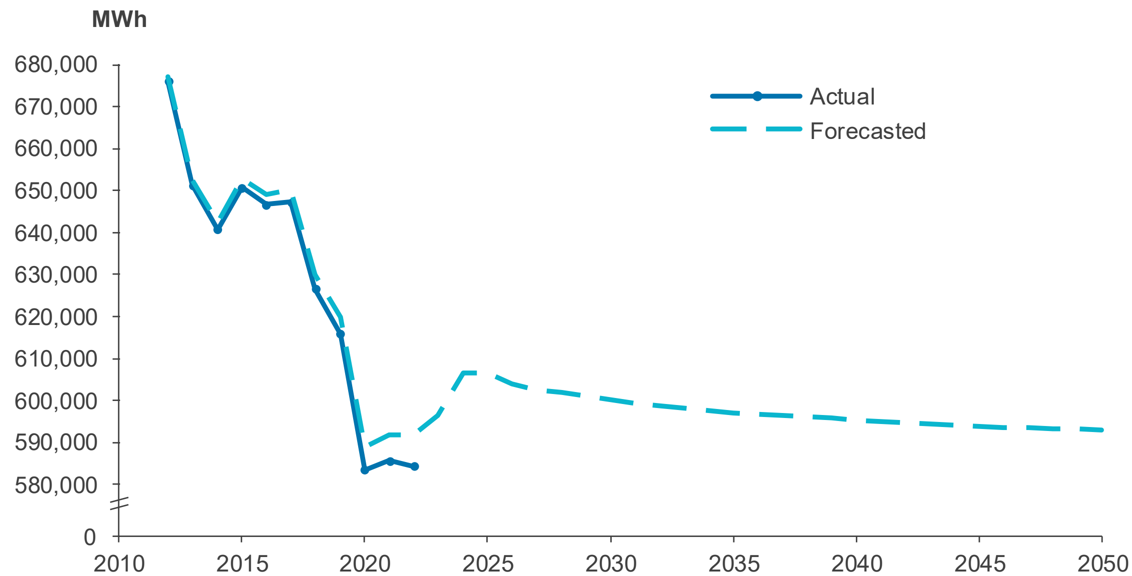
Total net generation requirements without the impact of on-site solar are the sum of retail sales to the three customer classes, distribution, and transmission losses, the TD&R Licensee's use, and any other unaccounted-for energy that may not be metered or otherwise included in retail sales. The combination of losses, own use, and other energy has averaged 10.5% of total net generation over the past five years, and the forecast remains at that monthly average. Total net generation declines slightly into the future excluding the impacts of BTMS. Retail sales without BTMS and total net generation forecasts are summarised in Figure 16 and Figure 17.

Figure 16. Energy Sales Forecast by Class without BTMS[5]



[5] 2012 – 2022 contains actual energy sales; 2023 and on are forecasted

Figure 17. Total Net Generation (TNG)



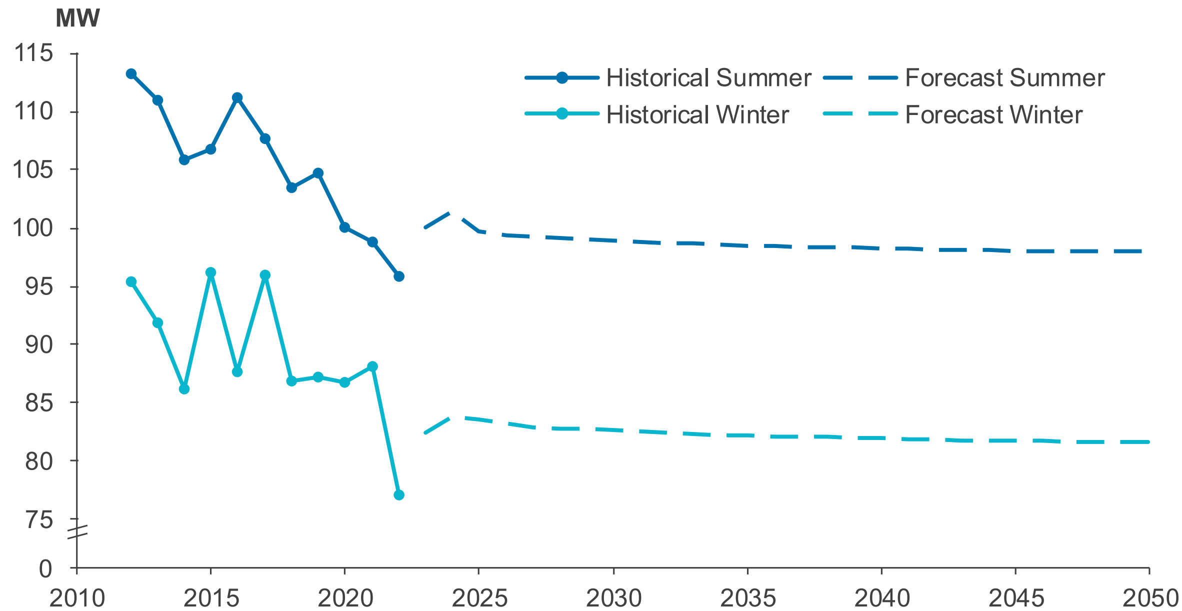
B.4 System Peak Demand

The TD&R Licensee's monthly system peak demand has decreased in recent years, following the trend of energy sales and total net generation. It is significantly impacted by the weather on the monthly peak day along with economic conditions and other underlying influences of load growth.

The monthly system peak demand forecast was developed using an econometric model relating monthly peak demand to monthly total net generation excluding BTMS impacts, heating degree days on the monthly peak day, cooling degree days on the monthly peak day, and monthly variables as needed to capture the unique system monthly peak demand shape. The total net generation driver excludes the impacts of BTMS since the system peak typically occurs in the early evening. Daily degree days capture the impacts of weather on the peak day while monthly total net generation captures the underlying drivers of long-term load trends and ties the peak demand forecasts to the system energy forecasts for consistency.

The system's peak demand forecast generally follows the trends of total net generation without BTMS impacts and has a slight decline expected over time. The system is expected to remain a summer-peaking system throughout the forecast horizon while the annual system load factor remains near 69 percent, in line with recent averages. The seasonal peak demands are illustrated in Figure 18.

Figure 18. Seasonal System Peak Demand Forecasts



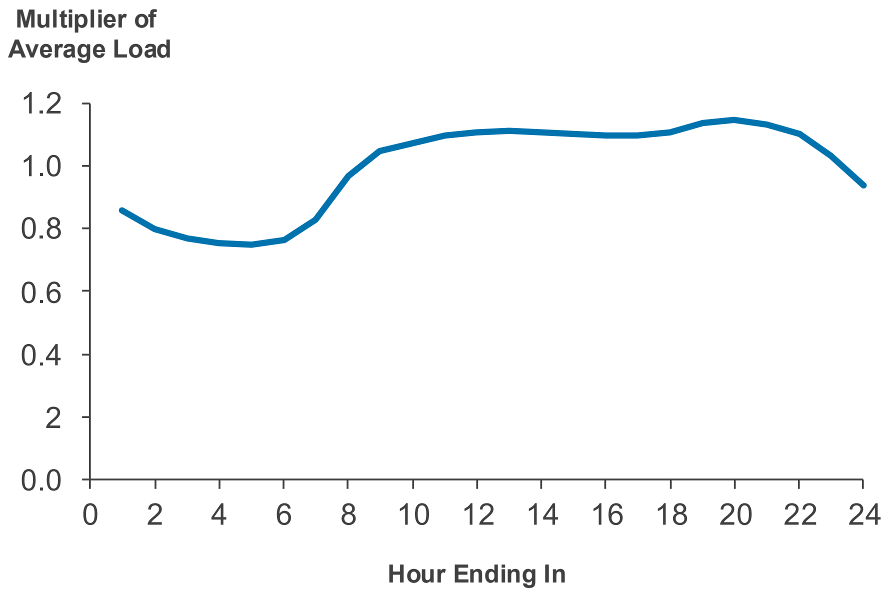
B.4.1 Load Shape

A load shape based on a typical meteorological year (TMY) of 2017 was used. This provided a more realistic shape excluding extreme weather events that are unpredictable. However, there were some weather disturbances, so the 2017 TMY shape was smoothed over these weather disturbances.

As displayed in Figure 19, the average hourly load shape is relatively flat. There is a long daily peak between the hours of 12:00 to 22:00, but demand goes down in the early mornings, which is expected. Figure 19 displays an average daily shape, which averages out differences by season and weekday or weekend. Bermuda is a summer peaking system, so load is typically higher in the summer which follows greater demand for cooling and HVAC, and lower in the shoulder months as seen in Figure 45 in Section H.2.2.

There is also load shape variation between weekdays and weekends. Load shapes are typically more uniformly distributed along the weekends and higher overall. On the weekdays, the load is generally higher in the afternoon to late evening hours and low during the morning.

Figure 19. Daily load shape multiplier to Average Load



B.4.2 Load Scenarios

The total energy and peak demand forecasts presented above represent one of many possible outcomes. Energy consumption and peak demands can be influenced by factors that are inherently difficult to predict, such as weather and economic growth. Therefore, it is important to develop flexible plans for meeting future power needs based on a range of forecast outcomes.

The IRP modelled uncertainty using a low and high load forecast, developed to examine rapid and slow economic growth under normal weather conditions.

The forecast ranges for demographic and economic variables have been developed by flexing the growth rate of the independent variables around the base-case forecast of growth for each variable. For instance, the real GDP forecast has a base forecast that remains flat while the optimistic economic scenario grows real GDP by 0.5% per year and the pessimistic economic scenario decreases it by 0.5% per year throughout the forecast horizon. The GDP ranges are then applied to the residential, commercial, and demand class forecasts to develop forecast ranges. The resulting economic growth ranges for total energy requirements are expected to diverge by 23% to 28% around the base projection by 2050. The economic growth scenarios plausibly broaden over time as the long-term economic growth uncertainty increases.

The optimistic and pessimistic economic energy requirements forecast ranges were applied to the peak demand forecast to adjust the corresponding peak demand forecast consistently and plausibly. The forecasts indicate that the annual system peak demand will range from 80 to 120 MW by 2050, given the assumptions mentioned herein.

The load forecast ranges for energy requirements are presented in Figure 20 while the peak demand forecast ranges are presented in Figure 21.

Figure 20. Total Energy Requirements Forecast Ranges (MWh)

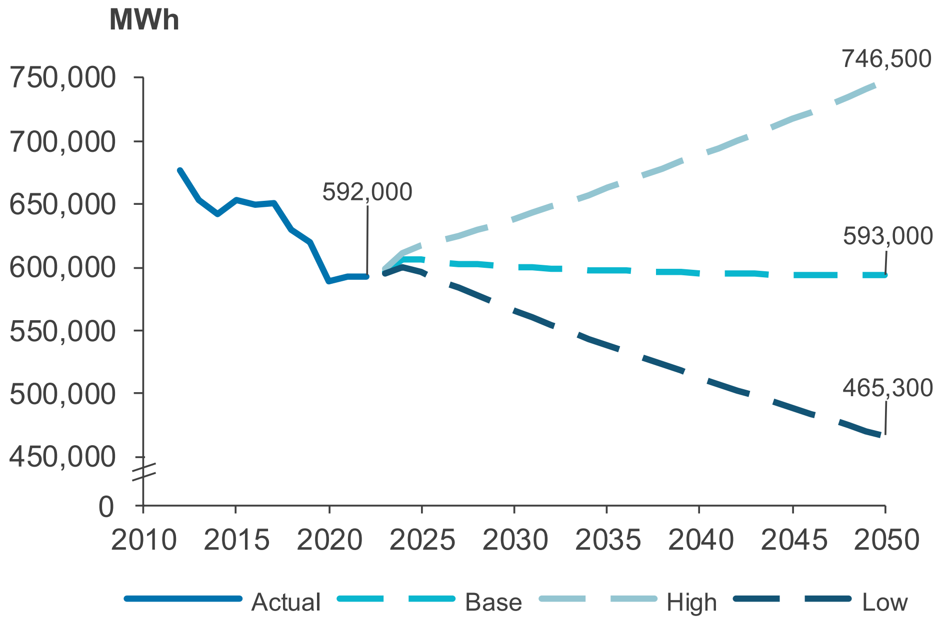
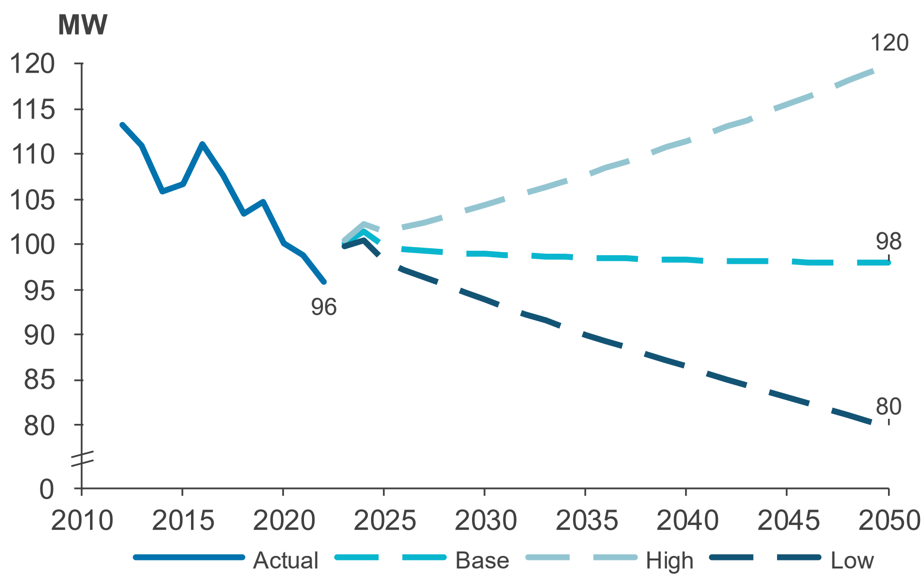


Figure 21. Annual Peak Demand Forecast Ranges (MW)



B.5 Load Forecast Adjustments

The load forecast presented above represents the base load forecast without any additional adjustments. Load-side adjustments are made in the model to account for the variations in load over time. Bermuda must account for the growth of electric vehicles, which increase load over time, in contrast to DERs such as behind-the-meter solar and storage, which decrease net load requirements. Both load changes have different load shapes distinct from the load shapes for the residential, commercial, and demand classes.

B.5.1 Electric Vehicles

To create an accurate electric vehicle (EV) load forecast, long-term EV adoption rates and their associated charging demand impact were assessed. EVs offer many benefits for customers to help reduce greenhouse gas emissions when renewables penetrate the grid more, but the impacts on overall energy requirements and peak load must be considered. Bermuda has some specific considerations when it comes to vehicles on the island.[6]

- **One car per household**: All residents of Bermuda are allowed only one automobile (private car) per household. This is important because although Bermuda is only 21 miles long and less than 2 miles wide, vehicles on the island are driven more miles per day because they are shared within households.
- **Limit on Car Size**: Cars must be at the pre-approved size for the island.
- **Supply Chain**: In Bermuda, cars drive on the left side of the road, and the supply chain for right hand drive cars is more limited. Cars also must be shipped to the island which can cause delays in receiving supply.

All potential constraints were included in developing the assumptions for the EV energy impacts.

Energy Impacts

Key inputs to determine the impact on the total energy (MWh) and the total peak demand (MW) included miles driven per day, number of current vehicles, customer adoption rates, and policy considerations. The impacts of EV adoption were evaluated. Key assumptions used as inputs are as follows:

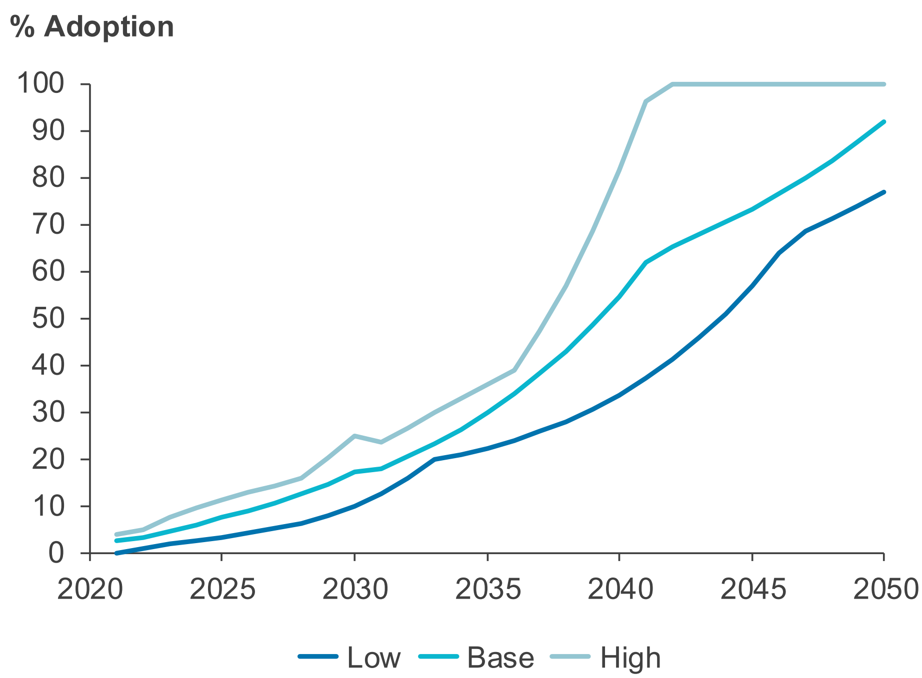
- Both battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV) were included given their ability to plug in and charge on the grid. The average trip length in Bermuda given its tip-to-tip length of 25 road miles is within most PHEV electric ranges. Therefore, battery power is assumed to be utilised for most of the trip.
- On average, Light-Duty Vehicles are driven 6,500 miles annually.
- Vans, SUVs, pickups, and light trucks use the same proportions.

[6] Transportation, Bermuda Online: http://www.bermuda-online.org/wheels.htm

- The forecast assumes no growth in total vehicles based on Bermuda's one car per household limits – there are approximately 23,000 light-duty vehicles on the road.
- In 2020 there were approximately 430 registered EVs overall in Bermuda.[7]

Figure 22 displays the adoption rates for the low, base, and high scenarios and Table 14 shows a table of the total energy demand from EVs annually.

Figure 22. EV Adoption Rate Scenarios



[7] Electrified Islands Report 2020

Table 14. Total Annual Energy Demand from New EVs (MWh)

Year	Low	Base	High
2024	4,569	4,750	4,932
2025	4,784	5,037	5,291
2026	5,063	5,392	5,721
2027	5,405	5,807	6,209
2028	5,840	6,320	6,800
2029	6,316	6,907	7,498
2030	6,915	7,661	8,407
2031	7,543	8,405	9,268
2032	8,289	9,283	10,277
2033	9,110	10,238	11,366
2034	10,070	11,333	12,596
2035	11,163	12,548	13,933
2036	12,402	13,866	15,329
2037	13,733	15,336	16,939
2038	15,244	17,066	18,888
2039	16,944	19,084	21,224
2040	18,882	21,465	24,047
2041	20,952	24,099	27,246
2042	23,171	26,889	30,606
2043	25,431	29,661	33,890
2044	27,797	32,466	37,135
2045	30,003	34,993	39,982
2046	32,335	37,639	42,943
2047	34,712	40,263	45,813
2048	37,202	42,943	48,684
2049	39,521	45,356	51,191
2050	41,969	47,856	53,742

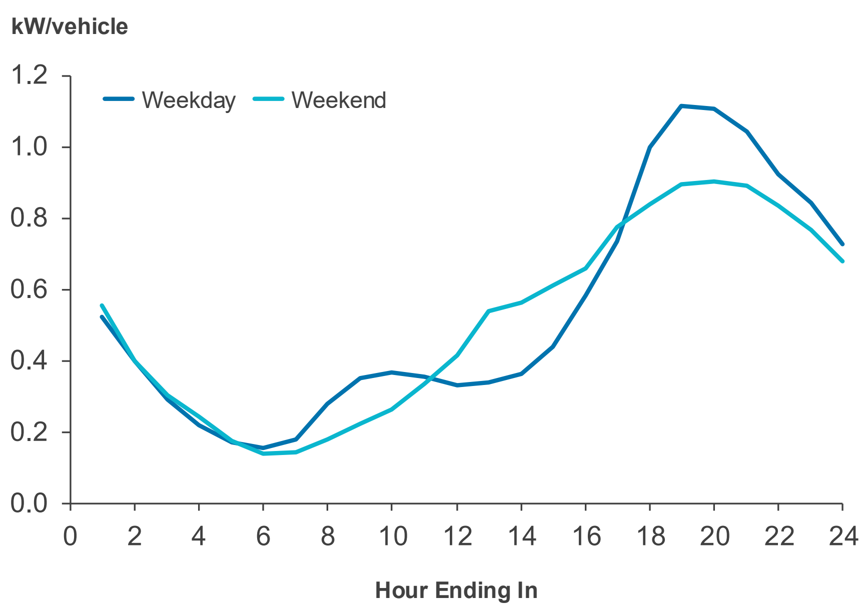
EV Load Shape

The U.S. Department of Energy's Alternative Fuels Data Center (AFDC) offers a tool, EVI-Pro Lite, that provides a way to estimate how much electric vehicle charging may be needed and creates a load profile that can be used in modelling.[8] Load shapes for the weekday and weekend electric load were estimated using Kahului, Hawaii as a proxy. Assumptions such as miles driven per day, temperature, charging type, and number of vehicles that were specified in the model are as follows:

- The EV load profile shifts as more cars come on the road.
- Average 6,500 miles per year.
- Average ambient temperature of 20°C
- Mostly Level 2 charging
- Preference for home charging
- Home charging strategy: delayed, start at midnight.
- Workplace charging strategy: delayed, finish by departure.

The developed load shape is used for all vehicle types and scenarios over the entire forecast period. The load shape can be seen below in Figure 23.

Figure 23. EV Load Shapes



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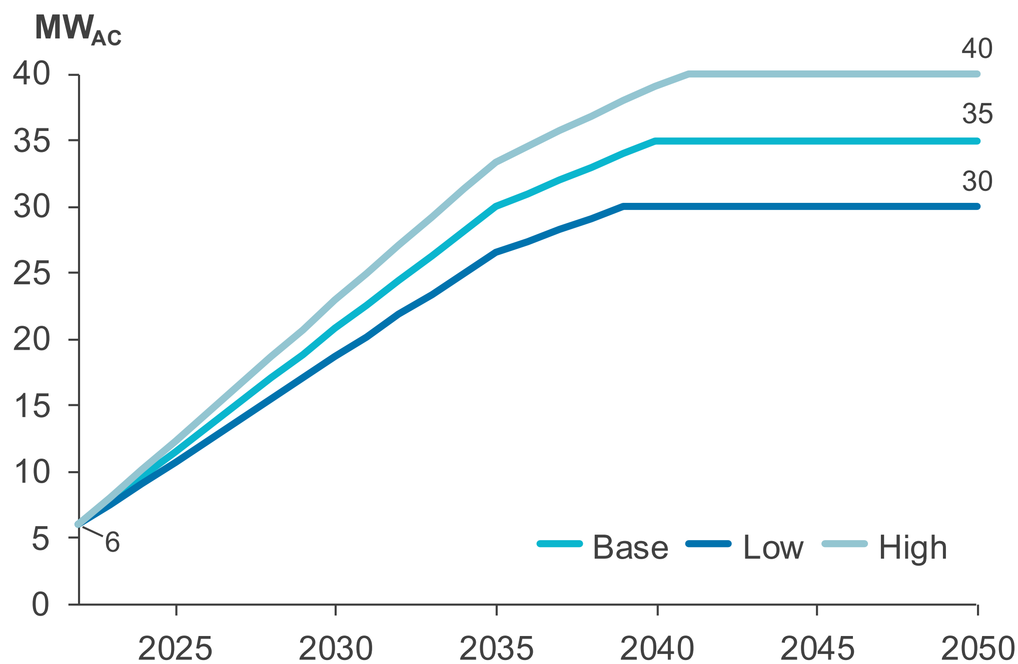
8 EV Infrastructure Projection Tool, DOE https://afdc.energy.gov/evi-pro-lite

B.6 Distributed Energy Resources

The DER forecast is mainly made up of BTMS. Bermuda has seen continued growth in rooftop solar capacity. About 3% of the TD&R Licensee's electric customers now have rooftop solar. Although the demand class has the largest adoption rates (circa 11 percent), the residential class has installed the most capacity.

Forecasts for the future deployment of rooftop solar were based on historical growth and customer adoption as well as spatial potential, energy potential, and grid stability limitations. The forecast can be seen in Figure 24. All three of the forecasts are based on a system maximum with annual limits to make sure the transmission and distribution (T&D) system has time for the necessary upgrades. The low, base, and high forecasts have a system maximum of 30, 35, and 40 MW respectively. A separate system impact study is being completed to determine the actual system limits for distributed generation.

Figure 24. BTMS Forecast (MW_{AC})



The generation shape used for utility-scale and floating solar was used to determine the capacity factor for BTMS, which is around 18 percent.

APPENDIX C - DEMAND-SIDE RESOURCE OPTIONS

The IRP considers demand-side and supply-side options for meeting future load requirements. This section describes the demand-side options included in Bermuda's portfolio analysis.

A study on EE and demand-side resource options was conducted. The TD&R Licensee does not currently have any demand-side management programmes (EE or DSM). This section describes the methodology taken to develop and analyse measures specific to Bermuda and the final assumptions for the programmes selected including impacted classes, costs, and implementation schedules.

C.1 Energy Efficiency

EE is a key demand-side resource that can help lower overall electricity demand and reduce the need to invest in new electricity generation and transmission infrastructure.[9] Other key benefits include risk management, reducing bills and price volatility, and lower carbon emissions. The remaining part of this section details how EE was considered in the modelling of the IRP and what assumptions were used.

C.1.1 Measure Development and Qualitative Screening

The study on EE and demand-side resource options covered a forecast horizon through 2050 and examined residential and commercial customers. Bermuda's load forecast and inputs, weather data, avoided costs, regional Technical Reference Manual (TRM), and prior studies were all used to analyse EE programmes suitable for Bermuda. The study resulted in a list of EE measures that would be feasible and appropriate to potentially deploy given the climate, building stock, and demographics of Bermuda. A qualitative screening was completed to identify measures most viable for Bermuda. Considerations for the qualitative screening included factors such as applicability to residential and commercial building construction materials and methods, equipment commonly found in Bermuda, typical building operations and maintenance practices, market availability, customer acceptance, equipment and labour costs, and other factors. The qualitative measure screening reduced the total number of measures going forward in the study down to 29 measures placed into a series of programme bundles that were categorised by sales class and end-use. They were also assigned delivery mechanisms (i.e., direct install, midstream, prescriptive, and custom) used to estimate project costs. Table 15 shows the final end-use bundles along with their measures.

9 Local Energy Efficiency Benefits and Opportunities, EPA.

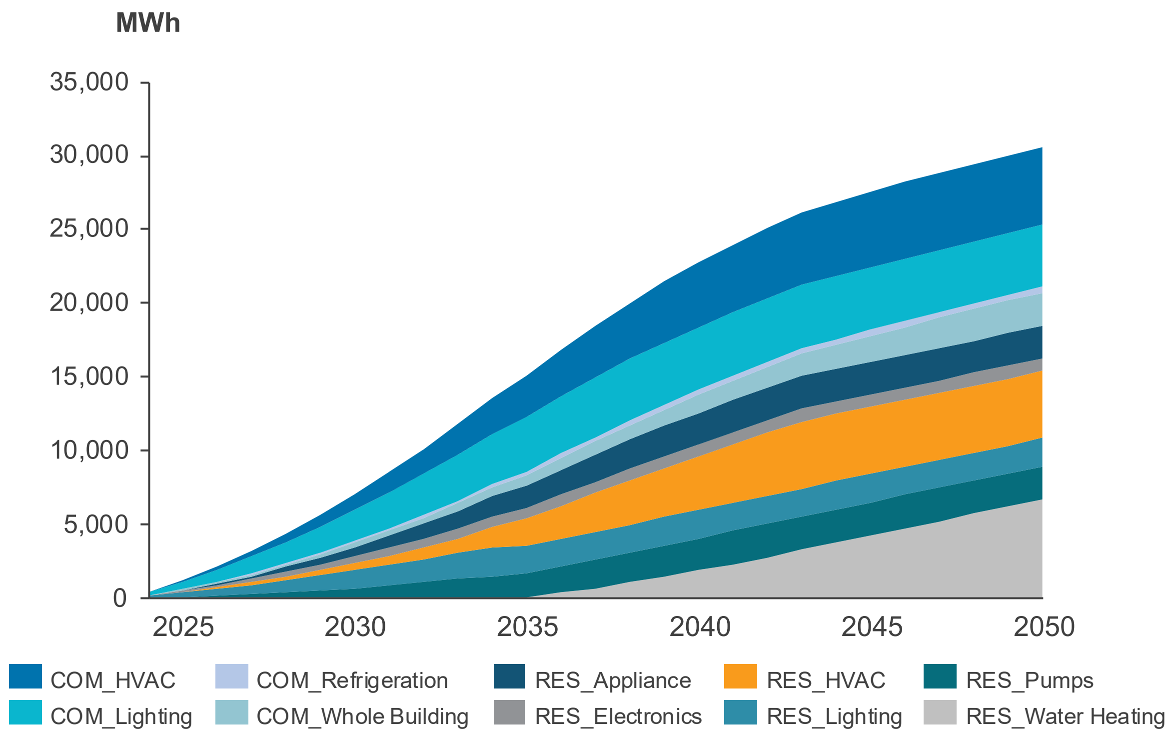
Table 15. Final EE Bundles for IRP

End-Use Bundle	Measure
Residential Appliances	Dehumidifier Air Purifiers Energy Star Clothes Washer Energy Star Refrigerator Energy Star Clothes Dryer Energy Star Freezer Energy Star Dishwasher
Residential Electronics	Advanced Power Strip Electric Vehicle Charger
Residential Heating, Ventilation, and Air Conditioning (HVAC)	Efficient Room AC Ductless Heat Pump Mini Split
Residential Lighting	Standard LEDs Specialty LEDs
Residential Pumps	Pool Pump
Residential Water Heating	Solar Water Heater Solar Pool Heater
Commercial HVAC	Variable Speed Drives for HVAC Supply and Return Fans Variable Speed Drives for HVAC Pumps and Cooling Tower Fans Electric Chiller Ductless Heat Pump Mini Split Small Commercial Thermostat
Commercial Lighting	Standard LEDs Specialty LEDs Interior High-Bay Fixtures Linear LEDs Exterior Area Lighting
Commercial Refrigeration	Refrigerator – Variable Speed Compressor
Commercial Whole Building	Retro-commissioning Advanced New Construction Designs

C.1.2 Measure Characterisation and Quantitative Screening

A cost-benefit model was developed around the 29 remaining measures. Critical assumptions such as savings, incremental costs, incentives, and measure life were compiled along with economic assumptions such as avoided costs, discount rate, inflation rate, and load forecasts. Each measure was then quantitatively screened for cost-effectiveness using the levelised cost at the measure level. The levelised cost utilised the incremental cost of the measure and its savings. The levelised costs were compared to the associated avoided fuel costs. All measures were found to be less expensive than the fuel costs and moved forward for inclusion in the savings potential analysis and modelling. The cumulative savings forecasted per bundle can be seen in Figure 25.

Figure 25. EE Cumulative Energy Savings



Based on the EE savings forecasted in Figure 25, the savings potential is expected to reach 0.8 percent of baseline demand over 5 years and 2.2 percent of baseline over 10 years. By 2050, cumulative EE savings potential is expected to reach 5.7 percent of baseline consumption. Residential and commercial lighting are the dominant end-uses in the near term through 2030, comprising more than 25 percent of the total potential. Residential solar water heaters and ductless heat pump mini-splits amount to approximately 22 percent of the potential by 2050. Commercial participation is estimated to reach 934 participants over 5 years, and residential participation is estimated to reach 10,109 over 5 years.

C.1.3 Modelling Considerations

The Levelised Cost of Energy (LCOE)[10] for each programme was compared against the LCOEs for the other supply-side resources. The LCOEs proved significantly lower than the supply-side resources, so all demand-side programmes were implemented in each portfolio. An implementation schedule was created to stagger the start of the programmes beginning sometime between 2025 and 2030. Staggering was done based on least-cost programmes that were the simplest to implement. Table 16 shows the EE bundle implementation schedule.

Table 16. EE Implementation Schedule

Year	Implementation Measure
2025	• RES Appliance – Dehumidifier • RES Appliance – Energy Star Freezer
2026	• RES Appliance – Energy Star Clothes Washer • RES Electronics – Advanced Power Strip
2027	• COM HVAC – Chiller Aux • COM Lighting – Interior (Interior High-Bay Fixtures,
2028	• RES HVAC – Efficient Room AC • RES Pumps
2029	• COM HVAC – Chiller Full • COM HVAC – Small Com (Ductless Heat Pump
2030	N/A
2031	N/A
2032	N/A
2033	N/A
2034	• RES Appliance – Energy Star Dishwasher • RES Electronics – Electric Vehicle Charger
2035	• RES HVAC – Ductless Heat Pump Mini Split
2036	N/A
2037	• RES Water Heating

[10] LCOE measures the lifetime costs divided by energy production. It allows for comparison of different technologies of unequal life spans, project size, different capital cost, risk, return, and capacities.

C.1.4 EE Scenarios

Figure 26 and Table 17 show a summary of the low, base, and high scenario results and specifications. The implementation schedule and programmes remain the same throughout each scenario.

Figure 26. Cumulative Energy Savings by Scenario

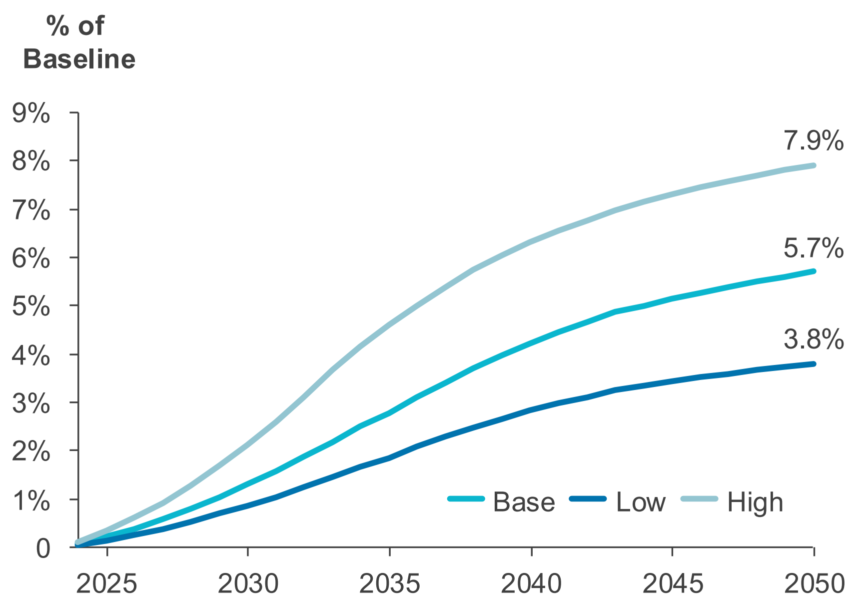


Table 17. EE Scenario Assumptions

Scenario Assumption	Low Savings	Base Savings	High Savings
Achievable Factor	20%	30%	40%
Measure Screening	TRC > 1	TRC > 1	None
Incentive Amount (% of Incremental Cost)	25%	50%	100%
Cumulative EE Savings as % of baseline in 2030	0.9%	1.3%	2.1%
Cumulative EE Savings as % of baseline in 2050	3.8%	5.7%	7.9%

C.2 Demand Response Considerations

As more renewables and distributed energy resources come online, demand response (DR) could be an effective tool for Bermuda to reduce peak demand without having to overbuild the system. A similar analysis to EE was completed for DR programmes. Six programmes were identified as most feasible for future consideration by the TD&R Licensee. These programmes are described below:

1. **Commercial and Industrial (C&I) Third-Party Curtailment:** By voluntarily reducing peak demand periods, companies could benefit from financial incentives and utilities can receive reductions in load during peak and near-peak conditions.

2. **Residential Behavioural Demand Response (DR):** Residential DR programmes incentivise homeowners to actively manage their consumption and engage in EE.

3. **Electric Vehicle Connected Charger Direct Load Control (DLC):** By actively managing and controlling the charging of EVs, the TD&R Licensee can control inherent after-work peaks from customers plugging in their vehicles to charge, balance resources on the grid, promote grid stability, and reduce energy costs.

4. **EV Managed Charging through Vehicle Telematics:** By optimising charging schedules based on real-time data and grid conditions, the TD&R Licensee could reduce the strain on the grid during peak hours.

5. **Storage DLC:** This offers the ability to actively manage and control electricity demand using stored energy from batteries to help balance the grid and mitigate peak demand.

6. **EV Fleets:** The EV fleet can lead to significant cost savings in terms of fuel and maintenance expenses and demonstrate a commitment to sustainability.

The IRP must consider DR. Based on the cost-benefit analysis; EE programs have a large impact on total energy requirements and peak demand. For this reason, EE programs are modelled, and DR programs are recommended for development and implementation in conjunction with regulatory tariff applications and processes.

APPENDIX D – EXISTING GENERATION ASSUMPTIONS

This section provides an overview of Bermuda's existing supply-side portfolio. The current supply-side resource mix comprises reciprocating engines, gas turbines, WTE, storage, and solar photovoltaics. Currently, most of the capacity is thermal and operated on heavy or light fuel oil, as described in Table 18.

Table 18. BELCO BG Owned Generating Thermal Units

Unit Name	Unit	Primary Fuel Type	C.O.D.[11]	Nameplate Capacity (MW)	Heat Rate (Btu/kWh)	Retirement Date
East Power Station	E5	HFO	2000	14.3	7,955	2040
	E6	HFO	2000	14.3	7,955	2040
	E7	HFO	2005	14.3	7,787	2045
	E8	HFO	2005	14.3	7,787	2045
North Power Station	N1	HFO	2020	14.3	7,631	2060
	N2	HFO	2020	14.3	7,631	2060
	N3	HFO	2020	14.3	7,631	2060
	N4	HFO	2020	14.3	7,631	2060
Gas Turbines	GT5	LFO	1995	13.0	13,266	2028
	GT6	LFO	2010	4.5	12,394	2035
	GT7	LFO	2010	4.5	12,394	2035
	GT8	LFO	2010	4.5	12,394	2035

D.1 Life Cycle Extension or Upgrade of E5 to E8

Two options to extend the life of EPS engines for baseload generation are investigated: the LCE and the life cycle upgrade (LCU). The LCE extends the useful life of the plant by 10 years, reducing the annual depreciation expense to customers. The life cycle extension is possible due to the reduced hours of thermal plant operation due to increased renewable generation. As this is simply the extension of engines' useful lives with no direct capital cost, it is applied as the default operational strategy. The capacity expansion modelling still permits early retirement of the engines if they are no longer cost effective or required to meet demand.

[11] C.O.D. refers to the commercial operation date.

The other option is the LCU of the EPS engines to a modern platform and extends the life by 30 years. These engine upgrades provide the same capacity rating at a higher efficiency. These upgraded engines will enable new fuel options such as LNG and, potentially, hydrogen.

D.2 Fuel Options

BELCO bulk generation (BELCO BG) currently utilises HFO and LFO as fuel sources in its reciprocating engines and gas turbines. The IRP investigates retrofitting existing generators to accommodate multiple fuel sources to reduce cost and emissions.

D.2.1 Switch to LFO

To employ this strategy, LFO fuel must be contracted in larger volumes for the NPS and EPS as the GTs already run on LFO. The EPS and NPS can switch to LFO without any additional infrastructure changes. LFO has environmental benefits over HFO such as reduced emissions. However, LFO is more expensive on a commodity cost and delivered fuel cost basis compared to HFO, which is discussed in section 7.3 of the Fuel Forecast. Table 19 shows the retirement and heat rate assumptions for the EPS and NPS engines running on LFO.

Table 19. LFO Switch Assumptions

Replacement Options	Fuel Type	LCE Retirement Date	LCU Retirement Date	Heat Rate (Btu/kWh)
E5	LFO	2040	2056	7,955
E6	LFO	2040	2056	7,955
E7	LFO	2045	2056	7,787
E8	LFO	2045	2056	7,787
N1	LFO	2060	2060	7,631
N2	LFO	2060	2060	7,631
N3	LFO	2060	2060	7,631
N4	LFO	2060	2060	7,631

D.2.2 Switch to Natural Gas

LNG is another fuel that has been assessed in this IRP. For this fuel case, LNG would be produced in the United States and shipped to Bermuda. Based on the 2016 LNG Feasibility study completed by Castalia,[12] LNG represents a feasible fuel option, using Ferry Reach Terminal to receive the LNG shipments along with the necessary infrastructure upgrades. The infrastructure upgrades would include additional terminal and regasification infrastructure that will need to be developed, along with pipelines and storage units. These capital costs were estimated in 2016 to be $130 MM for LNG infrastructure based on a receiving terminal and pipeline from Ferry Reach.

The LCU is necessary for the EPS engines to burn natural gas. This is referred to as the LNG Retrofit. The capital costs for LNG retrofits on E5 through E8 and N1 through N4 are captured in the modelling and displayed in Table 20. The earliest full conversion or upgrades for the engines would be in 2028.

Table 20. LNG Switch & Retrofit Assumptions (2022 $)

Replacement Options	Fuel Type	Retirement Date	CapEx ($/kW)	Heat Rate (Btu/kWh)
E5_Retrofit	LNG	2056	454.6	8,260
E6_Retrofit	LNG	2056	454.6	8,260
E7_Retrofit	LNG	2056	454.6	8,260
E8_Retrofit	LNG	2056	454.6	8,260
N1	LNG	2060	138.9	8,260
N2	LNG	2060	138.9	8,260
N3	LNG	2060	138.9	8,260
N4	LNG	2060	138.9	8,260
GT5	LNG	2028	0.00	11,700
GT6	LNG	2035	44.4	11,700
GT7	LNG	2035	44.4	11,700
GT8	LNG	2035	44.4	11,700

D.2.3 Switch to Methanol

A switch to methanol offers Bermuda a practical lower-emissions alternative to heavy fuel oil that can be implemented using proven technology and much of the island's existing fuel infrastructure. Methanol can be used in upgraded BELCO engines with relatively low execution risk, while retaining dual-fuel capability to provide operational flexibility and fuel security. It could also deliver meaningful local emissions benefits, including lower CO_2 emissions and

[12] Viability of Liquefied Natural Gas (LNG) in Bermuda : https://www.gov.bm/sites/default/files/Viability-of-Liquefied-Natural-Gas-in-Bermuda.pdf

substantial reductions in NO_x, SO_2, and particulate matter, while supporting competitive fuel pricing through long-term contracts and reliable regional supply. In addition, methanol's compatibility with existing storage and planned engine lifecycle upgrades makes it an option that could reduce transition complexity while supporting Bermuda's broader decarbonisation goals. The additional storage requirements, subsea pipeline and engine retrofits are expected to cost $70.6 million dollars in addition to the LCUs and are included in the financial model. The capacity build-out and dispatch of the P2LM portfolio with methanol was taken as identical to P2LL (LFO) portfolio.

D.2.4 Battery Energy Storage System

BELCO also owns a BESS that helps maintain its operating reserves, as described in Table 21.

Table 21. BELCO Owned Renewable / Storage Resources

	Nameplate Capacity (MW)	Storage Capacity (MWh)	C.O.D.	Annual Degradation Rate
Li-ion 30 min 10 MW	10	5.5	2019	2.2%

D.2.5 Third Party Bulk Generators

The TD&R Licensee purchases energy from an onshore solar facility, known as "The Finger", and a WTE facility, Tynes Bay. Assumptions for these two can be found in Table 22.

Table 22. Third Party Generator Nameplate Capacity

	Fuel Type	Nameplate Capacity (MW)	Capacity Factor
The Finger	Solar	6	21%
Tynes Bay	WTE	7.3	26.5%

Table 23: Existing Resource Assumptions – Detailed

Plant Name	**East Power Station**				**North Power Station**				**Gas Turbines**			
Unit Number	**E5**	**E6**	**E7**	**E8**	**N1**	**N2**	**N3**	**N4**	**GT5**	**GT6**	**GT7**	**GT8**
Heat Rate	7,955	7,955	7,787	7,787	7,631	7,631	7,631	7,631	13,266	12,394	12,394	12,394
Capacity (MW)	14.3	14.3	14.3	14.3	14.4	14.4	14.4	14.4	13	4.5	4.5	4.5
Primary Fuel Type	HFO	HFO	HFO	HFO	HFO	HFO	HFO	HFO	LFO	LFO	LFO	LFO
Variable O&M ($/MWh)	10.95	10.95	10.95	10.95	13.02	13.02	13.02	13.02	62.66	53.16	44.89	74.90
Fixed O&M ($/kW-year)	20.36	20.36	20.36	20.36	21.31	21.31	21.31	21.31	23.07	10.86	10.86	10.86
Forced Outage (%)	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Maintenance Rate (%)	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	1.64	1.64	1.64	1.64
Minimum Capacity	7	7	7	7	7	7	7	7	1	1	1	1
Resource COB	2000	2000	2005	2005	2020	2020	2020	2020	1995	2010	2010	2010
Resource Retirement	2040	2040	2045	2045	2060	2060	2060	2060	2028	2035	2035	2035
Min Up Time (hrs.)	3	3	3	3	3	3	3	3	—	—	—	—
Min Down Time (hrs.)	2	2	2	2	2	2	2	2	2	2	2	2
Emission Rate CO_2 (lbs./MMBtu)	173.32	173.32	173.32	173.32	173.32	173.32	173.32	173.32	161.27	161.27	161.27	161.27
Emission Rate NO_x (lbs./MMBtu)	10.35	10.35	10	10	10	10	10	10	0.12	0.11	0.11	0.11
Emission Rate Sox (lbs./MMBtu)	5.7	5.7	5.51	5.51	5.51	5.51	5.51	5.51	0.91	0.87	0.87	0.87

Table 24: EPS Engine LCU Retrofit Assumptions (2022 $)

Plant Name	East Power Station			
Unit Number	**E5_LFO**	**E6_LFO**	**E7_LFO**	**E8_LFO**
Capital Costs LCU ($/kW)	384.62	384.62	384.62	384.62
Resource COB	2000	2000	2005	2005
Resource Retirement (LCU)	2056	2056	2056	2056

Table 25: LCU – LNG Resource Assumptions (2022 $)

Plant Name	East Power Station				North Power Station				Gas Turbines			
Unit Number	**E5 Retrofit LNG**	**E6 Retrofit LNG**	**E7 Retrofit LNG**	**E8 Retrofit LNG**	**N1 LNG**	**N2 LNG**	**N3 LNG**	**N4 LNG**	**GT5 LNG**	**GT6 LNG**	**GT7 LNG**	**GT8 LNG**
Heat Rate (LHV)	8260	8260	8260	8260	8260	8260	8260	8260	11,700	11,700	11,700	11,700
Capacity (MW)	14.3	14.3	14.3	14.3	14.4	14.4	14.4	14.4	13	4.5	4.5	4.5
Capital Costs LCU ($/kW)	454.55	454.55	454.55	454.55	138.89	138.89	138.89	138.89	0	44.44	44.44	44.44
Fuel Type	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG	LNG
Variable O&M ($/MWh)	13.02	13.02	13.02	13.02	13.02	13.02	13.02	13.02	62.66	53.16	44.89	74.90
Fixed O&M ($/kW-year)	21.31	21.31	21.31	21.31	21.31	21.31	21.31	21.31	23.07	10.86	10.86	10.86
Forced Outage (%)	4	4	4	4	4	4	4	4	2	2	2	2
Maintenance Rate (%)	6	6	6	6	6	6	6	6	3	3	3	3
Minimum Capacity	7	7	7	7	7	7	7	7	1	1	1	1
Resource COB	2000	2000	2005	2005	2020	2020	2020	2020	1995	2010	2010	2010
Resource Retirement	—	—	—	—	2060	2060	2060	2060	2028	2035	2035	2035
Resource Retirement (LCU)	2056	2056	2056	2056	—	—	—	—	—	—	—	—
Min Up Time (hrs.)	3	3	3	3	3	3	3	3	—	—	—	—
Min Down Time (hrs.)	2	2	2	2	2	2	2	2	2	2	2	2
Emission Rate CO_2 (lbs./MMBtu)	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98
Emission Rate NO_x (lbs./MMBtu)	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.01	0.01	0.01	0.01
Emission Rate SO_x (lbs./MMBtu)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	4.57	4.57	4.57	4.57

APPENDIX E - NEW RESOURCE ASSUMPTIONS

In this IRP, new resource technologies are considered for their effects on cost to customers, reliability, and their ability to lower emissions. The RA Guidance included the following technologies for Bermuda to test in this IRP: fuel oils including existing fuels and lower sulphur content fuel oils, onshore and floating solar photovoltaic (PV), OSW, LNG, Liquified Propane Gas (LPG), biomass, and wave power generation.

A variety of baseload, peaking, renewable, advanced generation, storage, and alternative supply-side resources were considered. Furthermore, new fuel types, previously unused in Bermuda, were also considered.

The following are discussed in the upcoming section:

- **New Resource Assumptions:** Includes an overview of the assumptions for renewable energy resources and storage. This includes a discussion of capital costs13 operations and maintenance (O&M) costs, lifespan, capacity factor, earliest build date, and others.
- **Excluded Resources:** This includes an explanation for resources that were analysed during the development of the IRP but not included in the modelling process.

E.1 Solar

Solar PV systems use semiconductor materials surrounded by protective layers to convert sunlight into electricity. The system has a modular structure that allows it to be scaled to meet different levels of energy needs, large or small.

E.1.1 Onshore Solar

Utility-scale onshore solar PV is first made available as a resource option in the capacity expansion model in 2024. Current solar generation is modelled as a must-run resource with a generic hourly production profile representative of the region with a capacity factor of approximately 21% for utility-scale solar and 18% for BTMS. The percentage credit is modelled at an average of 2% and varies across the month (which aligns with the anticipated solar production curve). The hourly production profile and resultant capacity factor are based on modelling outputs of utility-scale and BTMS projects from a third-party software using a decade of hourly weather data.

[13] Capital costs are the all-in capital costs inclusive of equipment, EPC (engineering, procurement, and construction) costs, soft costs, interest during construction, and interconnection costs to the grid but exclude any grid upgrades or modifications, and any other balance of plant components.

Onshore solar capital costs were derived based on the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2023 capital costs with appropriate Bermuda adders. The fixed O&M costs and capacity factor were derived using estimates from an existing solar bulk generator.

Solar PV is made available in a configuration of 5 MW. The maximum annual capacity addition is 5 MW. In Bermuda, land constraints prevented solar capacity from reaching beyond 20 MW. Based on an estimate of available land space and potential siting of onshore solar, 20 MW reached the acreage limits for total resource capacity.

Table 26. Key Onshore Solar Assumptions

Capital Costs (2022 $/kW)	Fixed O&M (2022 $/kW-yr)	Variable O&M (2022 $/kWh)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
2,750	20	0	2028	30	5	16	21%

E.1.2 Floating Solar

Floating solar is a nascent renewable technology where solar panels are placed on the surface of the water. Due to Bermuda's land constraints, offshore renewable resources are needed to reach higher levels of renewable generation. Floating solar resources have previously been mostly in ponds and reservoirs[14] but are more recently being developed for the ocean.[15]Further studies are being conducted on the impact that salt water or wave action may have on the performance and lifetime of these resources.

Capital costs for floating solar were reviewed by stakeholders and corroborated with a U.S. Department of Energy, National Renewable Energy Laboratory (NREL) study between onshore and floating solar. The high fixed O&M cost compared to onshore solar internalises additional maintenance due to wave turbulence affecting system performance. The overall maximum build is also constrained by the siting specifics and is restricted by the environmental restoration efforts of the location. Since this technology is still in the early stages of development, the maximum capacity is 5 MW for the first two years, with assumptions of technological advancement increasing the annual limit to 10 MW thereafter.

[14] In 2016, Japan developed a 13.4 MW farm on a reservoir above a dam using 50,000 solar panels. Another plant in China can produce up to 40 MW which was constructed in 2017. (Smithsonian Magazine)
[15] In 2021, Singapore developed a 60 MW floating solar farm which uses 13,312 panels. 5MW-peak system installation is expected to produce an estimated 6 million kW-hours of energy per year. (The Straits Times)

Table 27. Key Floating Solar Assumptions

Capital Costs (2022 $/kW)	Fixed O&M (2022 $/kW-yr)	Variable O&M (2022 $/kWh)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
4,125	150	0	2032	27	5	80	21%

E.2 Offshore Wind

OSW is a potential option for Bermuda due to its location, climate, and ocean space, however further resource, technical and economic studies are required to verify the viability of OSW in Bermuda. There have been multiple studies completed that look at the feasibility of OSW potential, costs, and locations. Assumptions were developed from Greenrock & BVGAssociates,[16] Ricardo[17] and other reports for Bermuda and cross-referenced with Annual Energy Outlook[18] and operational wind farms.

There was variation among the studies regarding capital costs and O&M. The additional cost it may take to deliver and install large offshore turbines to Bermuda was considered. Capital costs were derived using EIA AEO 2023 estimates with a Bermuda adder and compared against United States OSW farms, such as Dominion's 2.5 GW offshore farm in Virginia.

The overall system maximum was 60 MW for OSW. It was predicted that operationally, OSW developers would bid for a project size of around 60 MW. Therefore, OSW was constrained to build the maximum capacity in the first economic year.

16 Bermuda offshore wind: LCOE assessment https://www.greenrock.org/projects/offshore-wind
17 Assessment of the Offshore Wind Potential in Bermuda
18 U.S. Energy Information Administration https://www.eia.gov/outlooks/aeo/

Table 28. Key OSW Assumptions

Capital Costs (2022 $/kW)	Fixed O&M (2022 $/kW-yr)	Variable O&M (2022 $/kWh)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
6,300	161	0	2032	32	15	60	41%

E.3 Wave

Due to Bermuda's limited acreage for new onshore resources and the potential to reach untapped renewable energy, wave power has been of great interest to Bermuda as it approaches commercial maturity. Wave power harnesses the motions of waves, converting mechanical energy into electrical energy.

Wave power is contingent on the wave height and wavelength at any given time. The TD&R Licensee has received data for a 250 kW device that would produce 700 MWh annually with an average power of 82 kW. Wave power is a great resource to offset solar and wind seasonal contingencies. Wave power was limited to a unit build of 5 MW and total max system build of 20 MW.

Table 29. Key Wave Assumptions

Capital Costs (2022 $/kW)	Fixed O&M (2022 $/kW-yr)	Variable O&M (2022 $/kWh)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)
10,179	529	0	2040	25	5	20	27%

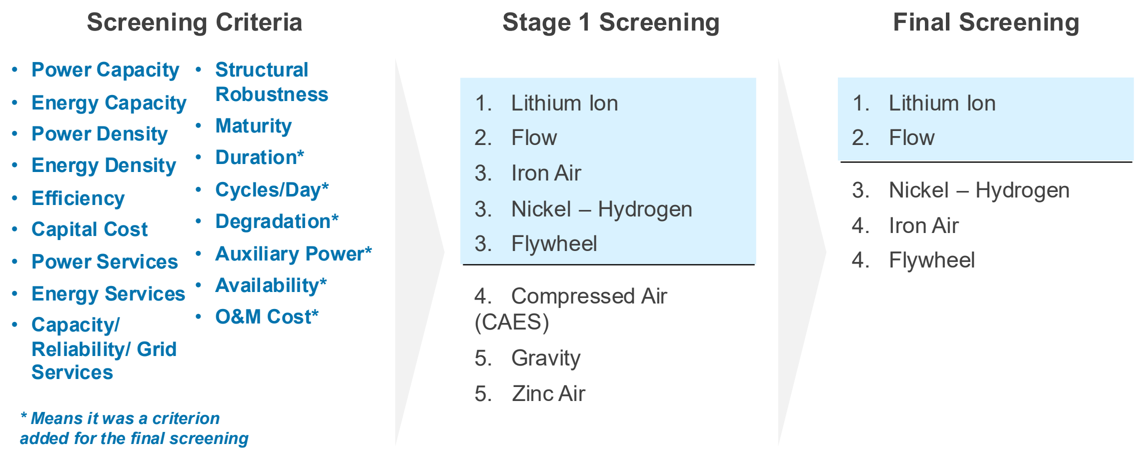
E.4 Storage

Utility-scale short and longer duration storage technologies were considered as peaking technologies that provide additional capacity during periods of peak energy demand through discharging of energy stored typically during periods of low energy demand. Deployment of these technologies can also help smooth out energy price volatility. The TD&R Licensee commissioned an energy storage study that considered both short- and long-duration storage technologies.

Multiple BESS technologies were evaluated that have been commercially deployed or are expected to achieve a technical readiness level sufficient for commercial deployment in the next three to four years. The study was completed specifically in the context of Bermuda. There were eight battery technologies scored in a semi-quantitative process against eleven key metrics. The list was then narrowed down for a final screening with an additional six criteria. Li-ion batteries were identified as the most viable storage technology as Li-ion was the most mature, energy-dense, and cost-effective technology. Flow batteries were second due to their projected future low costs, despite limited commercial deployment. Both technologies were modelled for the IRP.

A summary of the criteria used to screen the technologies and the resulting technologies modelled can be found in Figure 27.

Figure 27. Summary of the Storage Study Screening of Battery Technologies



E.4.1 Li-Ion Battery

Li-ion batteries store and discharge energy through the movement of lithium ions between a negative and positive electrode, separated by an electrolyte. These batteries are experiencing rapid growth in utility-scale deployments as their costs have fallen significantly and their value as a complement to renewable energy has increased. Li-ion batteries demonstrate advantageous operating characteristics that include high round-trip efficiency, high energy density, and lower self-discharge. The batteries can also respond to demand signals within a second, making them well suited for primary frequency regulation, i.e., providing an initial immediate response to deviations in grid frequency driven by sudden demand spikes or supply losses. However, Li-ion batteries have limited cycle life due to degradation; battery augmentation is required during the project lifetime to maintain performance.

In addition to the currently operational battery, new Li-ion battery builds are first made available in the model starting in 2027 and are modelled as a short-term energy storage option with a duration of two, four, and eight hours. The capacity expansion model optimises charging and discharging and considers a round-trip efficiency of 79% for the 2-hour battery, 84% for the 4-hour battery, and 86% for the 8-hour battery, and a self-discharge rate of 0.10% per day. As a duration-limited resource, the ability of Li-ion batteries to meet demand peaks will decline as greater amounts of renewable generation widen the length of demand peaks. All three durations of Li-ion batteries are made available in a configuration of 10 MW with no maximum, minimum, or annual build constraints in the model.

E.4.2 Flow Battery

Flow batteries were determined to be the second viable storage option for Bermuda. Flow batteries are a type of electrochemical battery where chemical energy is provided by two chemical components dissolved in liquids, pumped through the system on separate sides of a membrane. Ion transfer inside the battery occurs through the membrane while both liquids circulate in their own respective space. The energy capacity is a function of the electrolyte volume, and the power is a function of the surface area of the electrodes. Flow batteries have certain technical advantages over batteries with solid electroactive materials like Li-ion batteries, such as independent scaling of power (determined by the size of the stack) and of energy (determined by the size of the tanks), long cycle and calendar life, and potentially lower total cost of ownership. All flow batteries suffer from low cycle energy efficiency and have lower specific energy compared to Li-ion batteries.

Flow batteries are first made available in the capacity expansion model starting in 2025 and are modelled as long-duration storage with a storage energy capacity of twenty-four hours. Flow batteries were assumed to have a round-trip efficiency of 65% and a self-discharge rate of 0.02% per day. Flow batteries are made available in a configuration of 10 MW with no maximum, minimum, or annual build constrained in the model.

The smaller the storage duration, the greater the decline in capacity credits as more storage is added. Hence, the Li-ion technologies see declining capacity contribution while the 24-hour flow battery can provide full credit.

Table 30. Key Battery Assumptions

Battery Duration	Capital Costs (2022 $/kW)	Fixed O&M (2022 $/kW-yr)	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)
2 hr.	1,291	33	2028	20	10
4 hr.	2,300	38	2028	20	10
8 hr.	4,180	45	2028	20	10
24 hr.	11,974	79	2028	20	10

Table 31: New Resource Build Assumptions (2022 $)

Replacement Options	Earliest C.O.D.	Lifetime (yrs.)	Unit Capacity (MW)	Overall Max Build (MW)	CF (%)	Capital Costs (2022 $/kW)	Fixed O&M (2022 $/kW-yr)	Variable O&M (2022 $/kWh)
OSW	2032	32	15	60	41%	6,300	161	—
Onshore Solar	2028	30	5	16	21%	2,750	20	—
Floating Solar	2032	27	5	80	21%	4,125	150	—
Wave	2040	25	0.2	20	27%	10,179	529	—
Gas Turbine (GT5 Replacement)	2028	25	13	13	—	1,346	23	62.66
Gas Turbine Future Addition 13 MW unit	2028	25	13	13	—	1,346	11	53.16
Gas Turbine Future Addition 4.5 MW unit	2028	25	4.5	2.5	—	1,346	11	53.16
Li-ion 2hr 10 MW	2028	20	10	Not constrained	8%	1,291	33	—
Li-ion 4hr 10 MW	2028	20	10	Not constrained	17%	2,300	38	—
Li-ion 8hr 10 MW	2028	20	10	Not constrained	33%	4,180	45	—
Flow 24hr 10 MW	2028	25	10	Not constrained	28%	11,974	79	—

E.5 BESS Locations

A list of all the possible and feasible locations for the battery storage projects up to 2050 is provided below in Table 32.

Table 32: Potential Energy Storage Sites Around the Island

Location	sqm	MW	MWh
BELCO	8400	125	500
BAT	2500	40	160
NOB	1000	15	60
Belmont	1000	15	60
Airport	1000	15	60
Somerset	800	10	40
Boaz Island	420	5	20
Princess	400	5	20
Harrington	400	5	20
Fort Hamilton	300	5	20

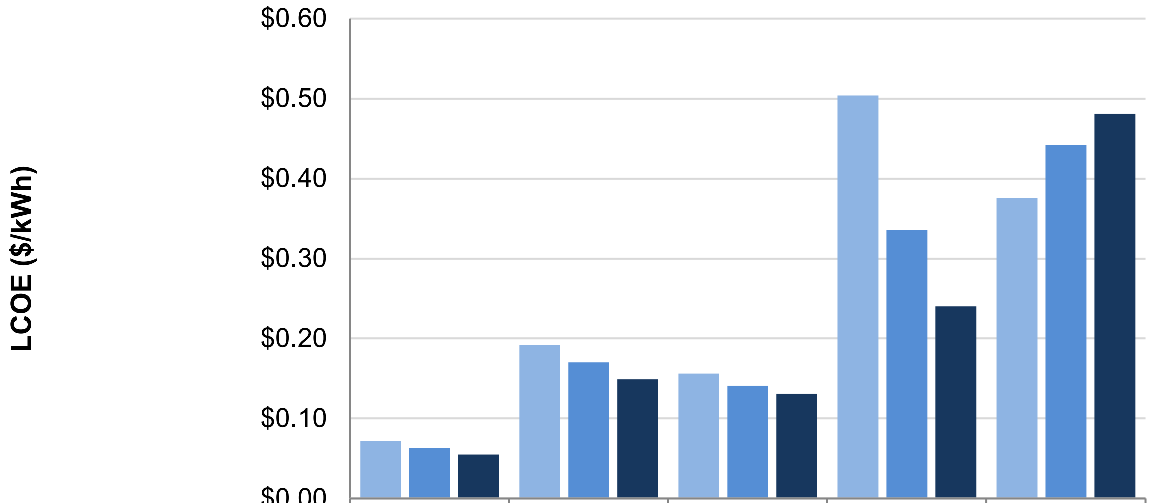
E.6 Levelized Cost of Energy of New Resources

The LCOE is useful to understand the potential costs of technology and is an important component in system planning. However, it should not be used in isolation when determining the lowest cost system that is also reliable. The LCOE narrowly looks at energy only, ignoring the contribution of resources to capacity and reserves. One type of technology may be the least expensive on its own but, due to its generation profile, may be more expensive at different levels of capacity. For example, solar energy could be sized to provide 100% of Bermuda's energy needs, however as solar does not generate at night, it requires additional system buildout not considered in the solar LCOE.

Figure 28 below gives the simplified LCOE[19] for each technology over the planning period and provides a helpful visual to indicate the lower cost technologies from an energy only perspective. The LCOE values are based on a set of input assumptions used for the IRP modelling and demonstrate the reduced cost of renewables over time and the increase in cost of biomass with time.

19 Simple Levelized Cost of Energy (LCOE) Calculator Documentation

Figure 28: Levelised Cost of Energy for New Resources in Bermuda



	Solar	Floating Solar	Wind	Wave	Biomass
2030 LCOE in Bermuda	0.072	0.192	0.156	0.504	0.376
2040 LCOE in Bermuda	0.063	0.17	0.141	0.336	0.442
2050 LCOE in Bermuda	0.055	0.149	0.131	0.24	0.481

The LCOE varies with weather, time, dispatch, and curtailment. Due to this variability, LCOE has limited usefulness as a relative cost metric for a system with technologies that have widely different capacity values. The Aurora model has built-in functionality within the capacity expansion model to assess the 'system value' and select resources based on the size and mix of resource options and a more comprehensive set of benefit streams. As a result, the capacity expansion model considers LCOE when determining the final portfolio mix but within the context of other system requirements. This enables the model to account for changing LCOE over the forecast horizon. For thermal resources, LCOE is affected by the dispatch of the unit and annual fuel price trends over time.

E.7 Excluded Resources

E.7.1 LPG

Consistent with the RA Guidance, Liquefied Petroleum Gas was considered as an alternate fuel option for the IRP. LPG is classified as a group of hydrocarbon gases typically including propane, butane, and isobutane derived from refining or natural gas processing that are liquefied via pressurisation[20] and would be delivered to Bermuda in bulk ocean tankers and stored at an existing storage facility.

[20] EIA Glossary

A study was completed to compare LPG to LNG to evaluate if LPG made sense to add as a fuel to the model instead of, or in addition to, LNG. To explore the feasibility of LPG for Bermuda, (1) commodity costs, (2) capital costs, (3) carbon intensity, and (4) relative feasibility were considered. On a pure commodity cost basis, propane near-term prices from 2023 to 2035 are $3/MMBtu higher than Henry Hub prices (about a 100% markup from current Henry Hub prices). However, the cost of transportation and storage is lower. This is particularly given that LPG is already on-island delivered via bulk carrier and ISO container. No additional capital costs are required to convert or retrofit existing GTs. Storage costs for LPG are less than LNG, as it can be fired from tanks versus LNG which must be stored cryogenically and regasified.

Despite the benefits, the carbon intensity of LPG (63 gCO_2/MMBtu) is higher than that of LNG (53 gCO_2/MMBtu).[21] Additionally, the EPS and NPS engine manufacturer does not offer an LPG package for these engines at this time. Currently only the GTs, which dispatch infrequently, can burn LPG. Given the operating profile of infrequent dispatch and the complexities and infrastructure associated with adding a fifth fuel to the mix. LPG was considered but not included in the current IRP for the reasons noted above.

E.7.2 Hydrogen

Hydrogen can play multiple roles within an electricity system. It can provide storage capacity during periods of high renewable generation and, depending on hydrogen prices, cycling capabilities for intermediate loads or generation capacity during periods of high electricity demand.

Hydrogen combustion turbines operate on the same principle as the Natural Gas Combustion Turbine (NGCT) systems but the fuel properties of hydrogen are different from that of natural gas. These properties lead to a difference in fuel handling, nozzle design, combustor design, and the need to control NOx leading to higher capital costs of hydrogen burning CTs relative to natural gas.

Due to the difficulties of transporting gaseous hydrogen, hydrogen storage and transportation are modelled using the Liquid Organic Hydrogen Carrier (LOHC). Although this makes hydrogen less efficient in terms of energy output, the chemical allows hydrogen to attach to a chemical in a liquid state and can be stored in fuel oil tanks. This eliminates any difficulties with transporting compressed or liquified hydrogen and the associated combustion risk.

Hydrogen was assumed to be green and has zero emissions. The commodity cost forecast was derived using electricity prices, water costs, and capital costs from electrolysers. The capital cost for hydrogen that the capacity expansion model uses is based on building a turbine that can combust hydrogen. The hydrogen is modelled as a fuel, which is produced outside of Bermuda but shipped and combusted on the island.

[21] Carbon Dioxide Emissions Coefficients, EIA

While hydrogen assumptions were developed, ultimately the resource option was not modelled due to the current state of this technology's advancement and the high dependency on a firm dispatchable resource within the first ten years of the forecast period. As a result, the resource has a high development risk that impacts other resources to the same extent. There were also safety considerations and large infrastructure overhauls on the generation, transmission, distribution, and end-use fronts that prevented this resource from being selected.

E.7.3 Ammonia

A study was performed to evaluate if the consumption of ammonia was feasible to help Bermuda meet future demand for clean energy. The assessment looked at the import cost of ammonia from the US Gulf Coast, on-island storage of ammonia, and on-island power production via ammonia capital costs, operational costs, and efficiency. It was found that the consumption of ammonia for power generation is not commercially available. The original equipment manufacturers (OEMs) that were contacted implied that the technology would not be available until the late 2020s and, as a result, reliable data could not be provided regarding capital and operation assumptions for an ammonia-fuelled power generator. This technology may be considered in future IRPs.

E.7.4 Biomass

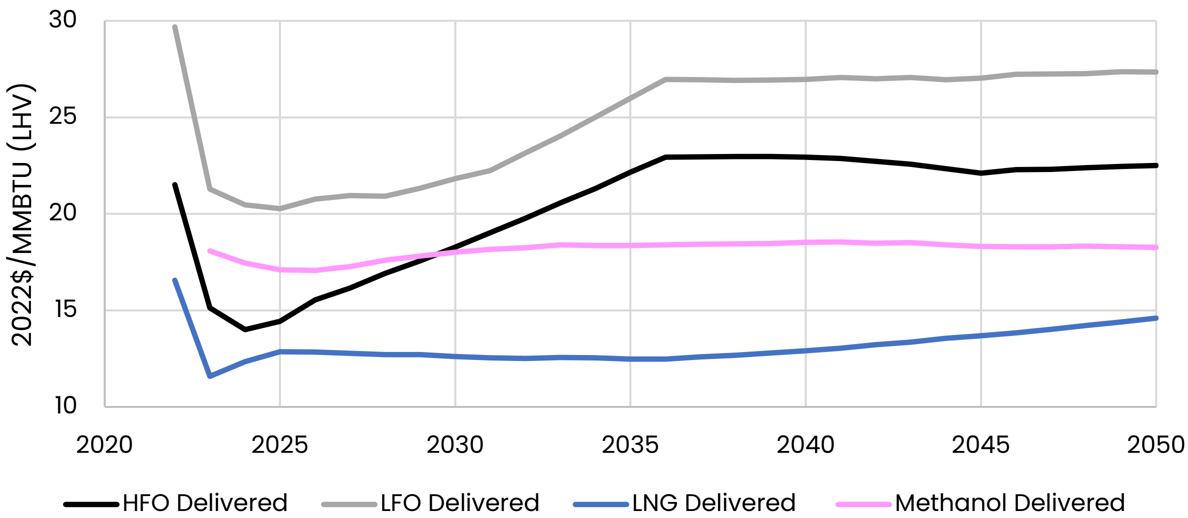
The 2023 IRP proposal considered biomass as a placeholder for a clean, dispatchable resource. To meet renewable penetration targets the 2019 IRP required a dispatchable resource when intermittent resources such as solar and wind are not meeting their production demands. Storage will make up for some of the misalignments in renewable energy production and demand, but another resource is still required. Whilst biomass was included in the 2019 IRP, further research has determined that biomass is not feasible for Bermuda, due to its fuel density requiring large storage volumes and frequent shipments for resiliency. Furthermore, storage challenges have been identified to store and keep wood-based pellets dry in a high humidity environment.

E.8 Fuel Forecast

Fuel price forecasts were developed for fuel oil, LNG, biomass, and hydrogen. Commodity costs were attained from public sources such as the EIA, Henry Hub, and others. Freight and margin were added to get the final delivered costs. Figure 29 shows the delivered price at port fuel forecast.[22] Additional detail for each fuel is described below.

[22] This includes no throughput for any of the fuels.

Figure 29. Delivered Price Fuel Forecast – Base Case



E.8.1 Fuel Oil

HFO and LFO price forecasts were developed using near-term forecasts and a blend of the CME Group Futures until 2026 with the AEO 2023 Low Oil Price Case.[23] These forecasts capture the near-term drop in oil and better calibrate fuel costs to represent current prices.

From 2026 to 2037, a blend of the AEO 2023 Reference Case was used with the AEO 2023 Low Oil Price Case to show a steady increase/return to the AEO Reference Case. 2038 onwards uses the AEO 2023 Reference Case for the long-term forecast.

E.8.2 LNG

To determine the forecasts for LNG, near-term Henry Hub price forecasts were used. These forecasts are determined based on a blend of forward prices and fundamental modelling: from 2023 to 2026, prices are based exclusively on forwards; from 2027 to 2029 prices are based on a blend of forwards and fundamentals; and from 2030 onwards, prices are based on fundamentals.

Infrastructure such as pipelines and regasification plants will be needed if LNG were to be selected as a fuels source on island. The capital investment in LNG infrastructure is included with a fair return on investment as a passthrough cost in the CRA revenue requirement model and not included as a variable cost in the delivered fuel price. This approach ensures that the costs are properly captured if the LNG infrastructure becomes stranded.

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[23] CME Group Futures

E.8.3 The Evaluation of LNG in Bermuda

Since 2015, it has been reported by Castalia[24], Leidos[25], CRA[26], and the RA[27] that LNG is the long-term lowest cost and cleanest fossil fuel for electricity needs in Bermuda. Despite these independent and expert findings, progress toward a cleaner fuel has not been realised.

Had Bermuda adopted a more flexible and forward-looking approach to change, the country may have already been further advanced in its transition to cleaner, lower-carbon fuels alongside renewable energy. There remains an opportunity to reflect on past decisions, apply those lessons learned constructively, and continue progressing toward a more sustainable and resilient energy future.

Viability of Liquefied Natural Gas (LNG) in Bermuda 2015

The 2015 Castalia report prepared for the Government of Bermuda finds that LNG is a viable and attractive option for Bermuda's electricity sector, driven by the need to reduce high and volatile energy costs from heavy reliance on imported oil. Global market trends including increased natural gas supply and declining prices indicate that LNG could be competitively priced even after accounting for transportation. Advances in small-scale LNG technology further support feasibility for island systems like Bermuda.

The report concludes that *"importing LNG could lead to lower electricity prices and lower emissions from electricity generation. As a result, we recommend a process for determining the best way for Bermuda to procure LNG."*

LNG was estimated to reduce electricity generation costs by approximately 15% to 42% while also lowering emissions compared to oil-based fuels, supporting both economic and environmental objectives. However, it emphasizes that while LNG is clearly viable, further detailed analysis is required—particularly around infrastructure siting, costs, and procurement—to determine the optimal implementation approach. Overall, the study supports continued evaluation and development of LNG as part of Bermuda's future energy strategy.

LNG in the 2016 IRP

The 2016 BELCO Integrated Resource Plan was developed prior to the establishment of the Regulatory Authority and was prepared by an independent third party (Leidos) to assess Bermuda's long-term electricity supply options. The report evaluated multiple pathways to replace an aging oil-based generation fleet while balancing cost, reliability, and environmental objectives. Its analysis found that natural gas–based scenarios, particularly those involving LNG, consistently outperformed fuel oil and LPG alternatives. LNG pathways demonstrated lower long-term production costs than business-as-usual, improved fuel price stability, and

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24 Castalia, Viability of Liquefied Natural Gas (LNG) in Bermuda, 2016
https://www.gov.bm/sites/default/files/Viability-of-Liquefied-Natural-Gas-in-Bermuda.pdf

25 Leidos, 2018 Integrated Resource Plan Proposal, www.ra.bm

26 CRA, 2023 IRP Proposal, Integrated Resource Plan (IRP) Proposal Consultation

27 Regulatory Authority of Bermuda, Bermuda's First Integrated Resource Plan (IRP) 2019,

reduced emissions, while aligning with Bermuda's energy policy objectives. Despite requiring higher upfront capital investment, the 2016 IRP demonstrated that these costs are offset by sustained fuel savings and reduced exposure to oil price volatility over the study period.

The 2016 IRP therefore supports the continued evaluation and development of LNG as a core component of Bermuda's future energy mix. It identifies LNG-based pathways as a "least-regret" option that balances affordability, resilience, and sustainability, while enabling integration of demand-side management, solar PV, and energy storage to enhance overall system performance. These findings provide a strong, independently derived basis for the ongoing recommendation of LNG in subsequent IRPs, demonstrating that long-term operational savings and system benefits justify the initial capital investment and support Bermuda's broader energy transition objectives.

The 2016 IRP was published prior to the Regulatory Authority being stood up. However, the report produced by a third party (Leidos) determined that a full conversion to LNG was the most affordable option for Bermuda electricity needs.

LNG in the 2018 IRP Proposal

The 2018 BELCO IRP Proposal sets out a structured evaluation of future generation pathways over a 20-year study period, considering multiple fuel options and resource mixes. Four scenarios were assessed, including continued reliance on fuel oil, fuel oil with renewables and demand-side measures, conversion to LNG, and a liquefied petroleum gas (LPG) pathway. These scenarios were evaluated using both quantitative modelling (levelized cost, production cost, and reliability metrics) and qualitative criteria such as environmental performance, energy security, and implementation feasibility.

The results indicate that full conversion to natural gas (Scenario 3) was ranked highest overall when combining cost and qualitative factors. While the natural gas scenario involved higher upfront capital costs, primarily due to LNG infrastructure and conversion of existing assets, it was identified as the most robust option under sensitivity testing, particularly in high fuel price conditions. It also delivered the lowest carbon emissions and improved reliability metrics relative to the other scenarios.

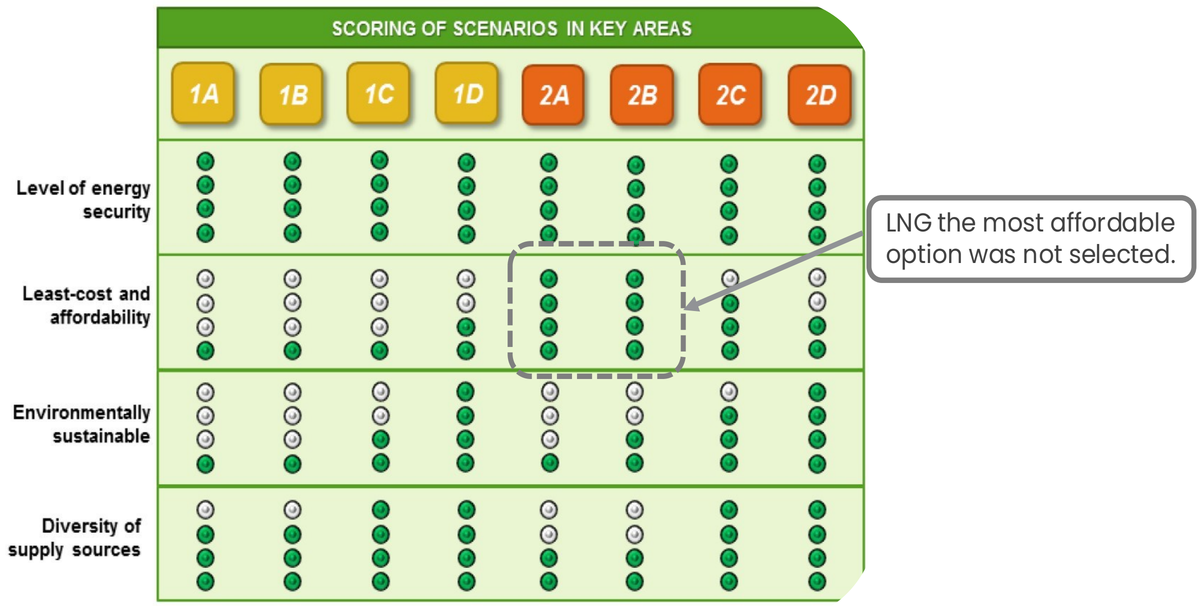
Accordingly, LNG was again identified as the preferred plan in the 2018 IRP proposal as its long-term benefits fuel cost stability, reduced emissions, and improved system resilience supported its selection over fuel oil and LPG alternatives.

LNG in Bermuda's 2019 IRP

The Regulatory Authority's 2019 Integrated Resource Plan presented a comprehensive evaluation of generation pathways against key criteria including energy security, affordability, environmental sustainability, and diversity of supply. While the IRP ultimately selected a renewable-led pathway as the preferred option, its underlying analysis identified LNG-based scenarios as the most cost-effective solution for Bermuda's electricity sector.

As illustrated in the adapted Figure 30, LNG scenarios received the highest scores in the "least-cost and affordability" category, demonstrating a clear advantage from a purely economic perspective. However, the final selection reflected a broader policy balance, where environmental considerations and long-term decarbonization objectives were weighted more heavily than cost, resulting in the selection of a pathway that was not the least-cost option identified in the Authority's own assessment.

Figure 30: Extract from 2019 Integrated Resource Plan



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LNG in the 2023 IRP Proposal

The BELCO 2023 IRP Proposal (revised 9 May 2024) found that, from a purely economic perspective, LNG remained the lowest-cost pathway when evaluating long-term system costs across modelled portfolios. However, despite this cost advantage, the IRP proposal identified significant practical constraints, including high upfront infrastructure investment, execution risk, and exposure to contractual and market uncertainty. More importantly, strong public opposition to new fossil fuel infrastructure and alignment pressures from national energy policies that prioritize rapid decarbonization reduced the viability of LNG as the preferred strategy.

As a result, the 2023 IRP proposal selected an alternative portfolio focused on aggressive renewable integration—targeting approximately 85% renewable energy by 2040 and deep emissions reductions—while relying on interim measures such as LFO conversion and storage deployment rather than a full LNG transition. The plan explicitly acknowledges that these targets are highly ambitious and may stretch technical, financial, and execution realities, reflecting a disconnect between modelled least-cost outcomes and policy-driven objectives. LNG is therefore retained as a contingency ("pivot") option rather than the primary pathway.

APPENDIX F - SCENARIO AND SENSITIVITY ANALYSIS

As part of the 2026 IRP analysis, we account for the latest market, technology, and policy assumptions. BELCO evaluated two market scenarios, in addition to the REF scenario, that describe plausible futures that may develop over time and result in a materially different set of market conditions under which BELCO will need to serve customer load requirements. Each scenario is driven by a set of thematically oriented fundamental market assumptions. These scenarios are used to test the robustness of BELCO portfolio choices to future market conditions. Table 33 summarizes the key drivers of each scenario in a matrix.

Table 33. Scenario Assumption Matrix

Scenario Concept	REF	HCP	TDD
Technology Costs	Base	Base	Low
Fuel Prices	Base	High	Low
Load Growth	Base	Low	Base
Demand-Side Management	Base	High	Low
EV Penetration	Low	Base	High
BTMS Penetration	Base	High	Base

F.1 High Commodity Price Environment Case (HCP)

As Bermuda is currently a fuel oil-dependent nation, the HCP scenario tests an environment where commodity costs for fuel oil and LNG are high. This is caused by geopolitical tensions and production challenges that keep oil and natural gas prices high in the long run. A high commodity price environment pushes retail electric rates and gasoline prices higher accelerating distributed generation and electric vehicle penetration. Sustained, high electric and fuel prices affect tourism and the cost of doing business on the island and negatively impact demand growth while promoting investments in demand-side management programs. Technology costs remain stable and decline at the same rate as the REF scenario with gradual relief of supply chain pressure over time.

F.2 Technology Driven Decarbonization Case (TDD)

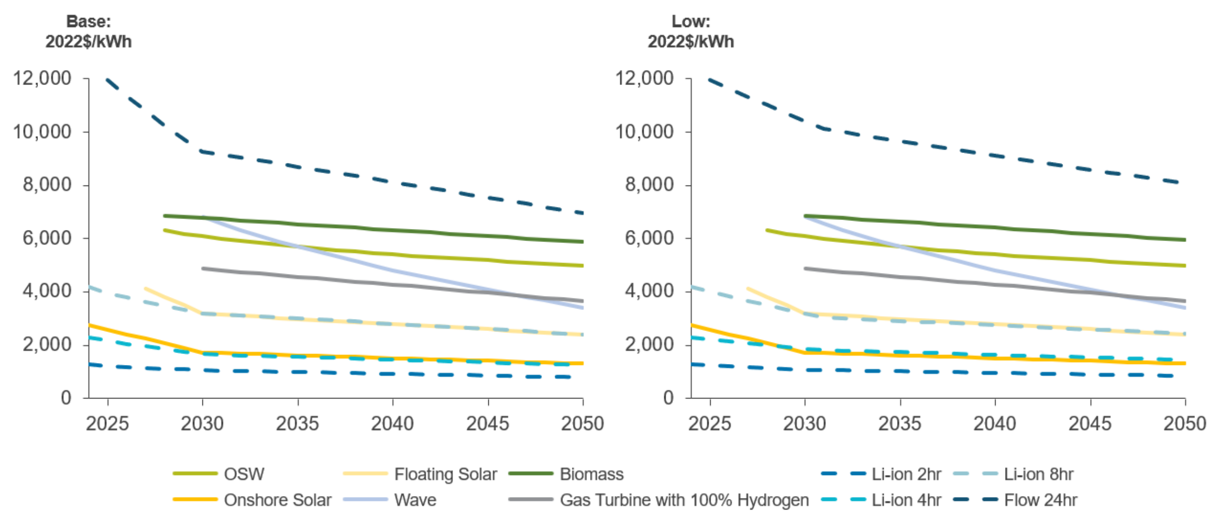
The TDD scenario evaluates an aggressive global shift to decarbonize the electric sector. Global technology development and the resolution of supply chain issues push towards a decarbonized economy supporting renewables and other non-emitting technologies with large-scale electrification in the transportation sector. As technology costs reduce, there is a significant shift away from fossil fuels in all sectors of the economy, putting downward pressure on global oil and natural gas prices. Low fuel prices in the long run disincentivize DSM programs but keep distributed generation investments at a base level due to lower technology costs. Demand growth on the island is unaffected as fundamental macro drivers for the Bermuda economy remain unchanged.

F.3 Scenario Inputs

F.3.1 Scenario Technology Cost Assumptions

To calculate scenario technology costs, we used the same starting CapEx for each technology and altered the technology learning rates over the forecast period. WE used the "Moderate" and "Advanced" learning rate curves from NREL's Annual Technology Baseline (ATB) and applied them to the REF and TDD scenarios respectively. The advanced learning rates have an accelerated cost decline curve giving lower technology costs over the forecast period. CapEx for the various technologies over the forecast period can be seen in Figure 31.[28]

Figure 31. Scenario Technology Assumptions - Base and Low



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[28] Note that CapEx over the forecast period is displayed in nominal terms and does not reflect inflation, only learning rates.

F.3.2 Scenario Fuel Cost Assumptions

Fuel cost ranges were compiled based on various predictive scenarios within the EIA AEO 2023.[29] We used a combination of our internal fuel forecasts and EIA scenarios to arrive at the final fuel forecast scenarios.

The purpose of altering commodity costs is to present a significant downside in terms of an aggressive high fuel price scenario but a moderate "upside" with a slightly less aggressive low fuel price. As a result, the EIA forecast scenarios used for the Low forecast were "Low LNG Price" and "High Oil and Gas Supply" and the High forecasts were based on the "Low Oil and Gas Supply" scenario, which was the most downside forecast. Final delivered costs included the same adders as the REF scenario.

F.3.3 Scenario Load Assumptions

Load ranges revolved around varying gross system demand and load-varying resources such as EV, EE, and BTM Solar. The underlying system load is based on historical load and customer data. Changes to these resource levels can represent plausible future load conditions on the BELCO system.

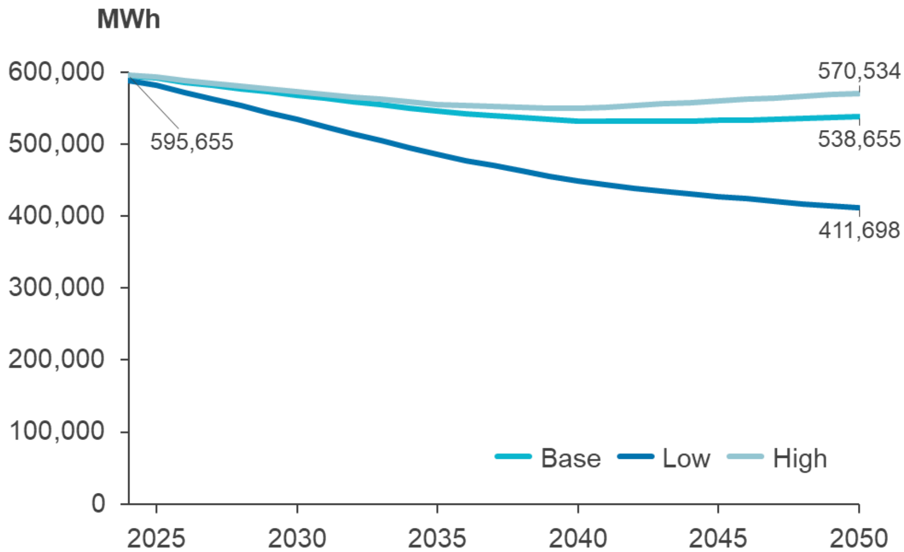
Load-varying resources impact net load, which is the ultimate demand that supply side resources will need to meet. As described further in Sections B.5 and APPENDIX C - , these resources are added as either a demand side or supply side resource. A higher EV penetration adds more demand to the system due to greater demand for EV charging, while a higher penetration of DSM and BTM Solar lowers the overall system load. These load-varying resources will complement the underlying system load.

The TDD case flexes the EV, EE, and BTM projections with the gross demand being the same as the reference case. We did not change the system base load in the TDD case because historical data for BELCO has not shown any significant load growth. Increasing EV load and lowering DSM and BTM penetration results in a higher overall net load case.

The HCP case uses the low system load in addition to decreases in EV and increases in DSM and BTM resources. These effects will simulate an overall net load case with less generation needed from baseload generation and renewables.

29 Table 12. Petroleum and Other Liquids Prices, AEO 2023

Figure 32. Net Load (Energy) Scenario Comparison



F.4 Scenario Results

The scenario analysis used the portfolios from the REF scenario but altered dispatch against different future uncertainties. The main variables that were modified were net load, commodity prices, and technology costs. Overall, emissions do not vary across scenarios. Overbuilding from curtailment and cost is a big risk. Exposure to fuel prices is also a significant risk. Demand impacts are more muted as some scenario variables have an offsetting effect on the other uncertainties.

In the HCP scenario, a lower net load outlook was paired with a higher outlook for commodity prices. Lower load leads to less need for engines to dispatch and thus lower emissions. As the buildouts are the same, the HCP scenario experiences higher curtailment as demand is lower and renewables are not dispatchable. The increase in curtailment is also seen in an increase in cost to customers since customers must still pay for resources that are not dispatching as much. The costs in this scenario have the highest rate exposure as fuel prices are higher and portfolio capital costs and fixed costs are recovered over smaller volumes.

In the TDD scenario, a slightly higher net load outlook is combined with a lower outlook for technology costs and commodity prices. Higher load in the TDD scenario results in greater emissions as engines dispatch more over the forecast period. Curtailment, and therefore costs, only vary slightly below the REF scenario.

APPENDIX G – PORTFOLIO RESULTS

The following section presents the results of installed capacity and energy output of every portfolio.

Figure 33: Installed Capacity of P2F (Affordability & HFO)

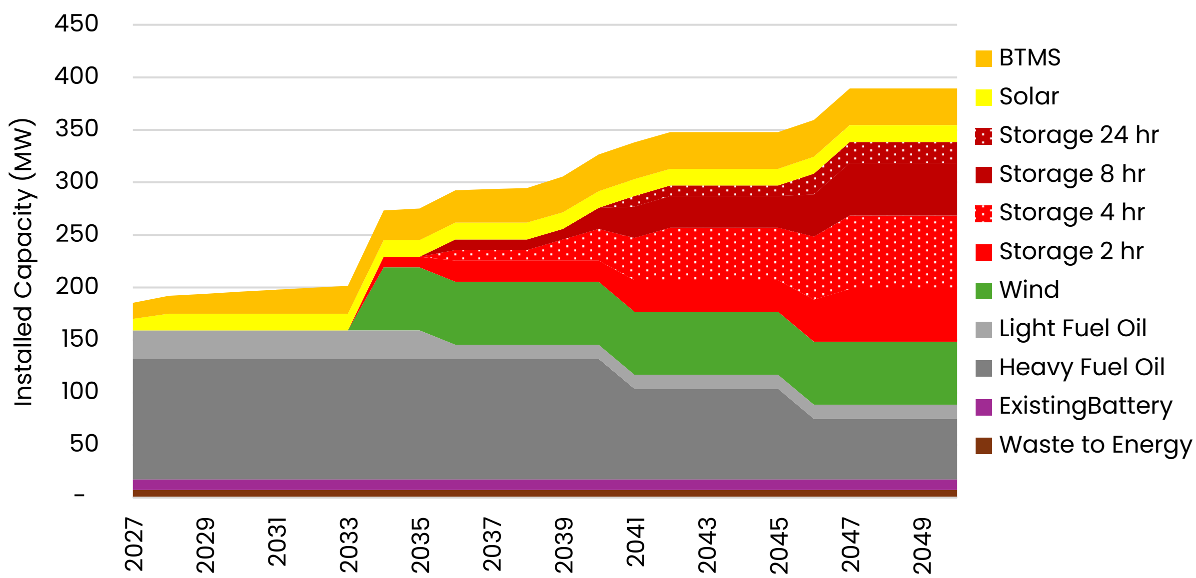


Figure 34: Energy Output of P2F (Affordability & HFO)

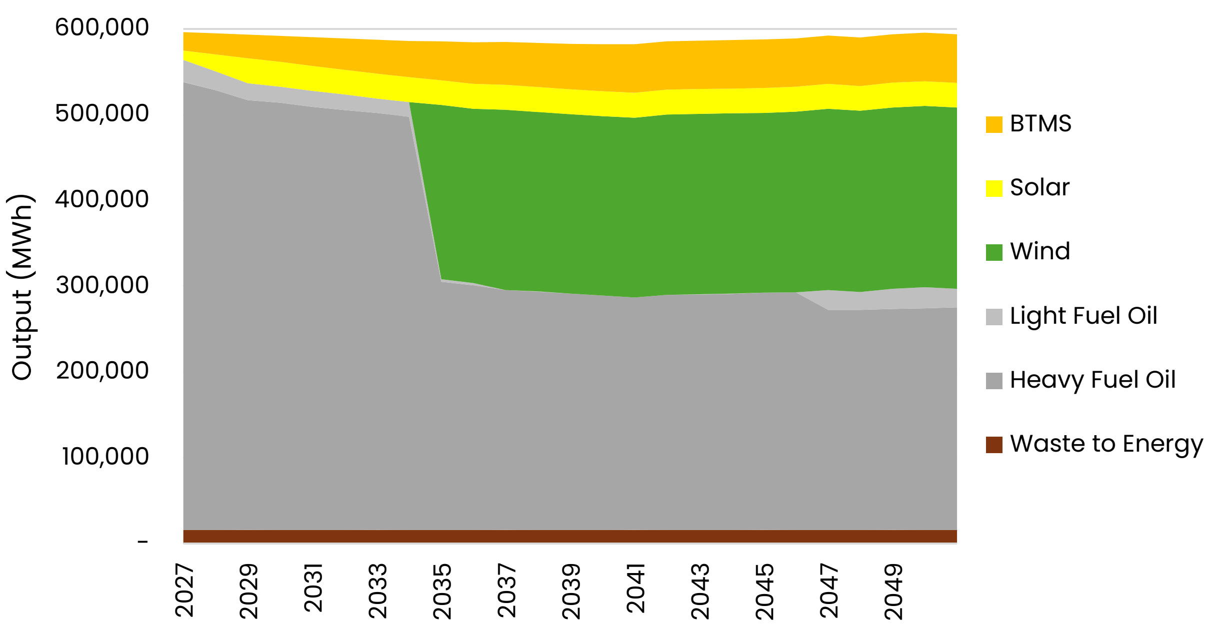


Figure 35: Installed Capacity of P2L (Affordability & LFO)

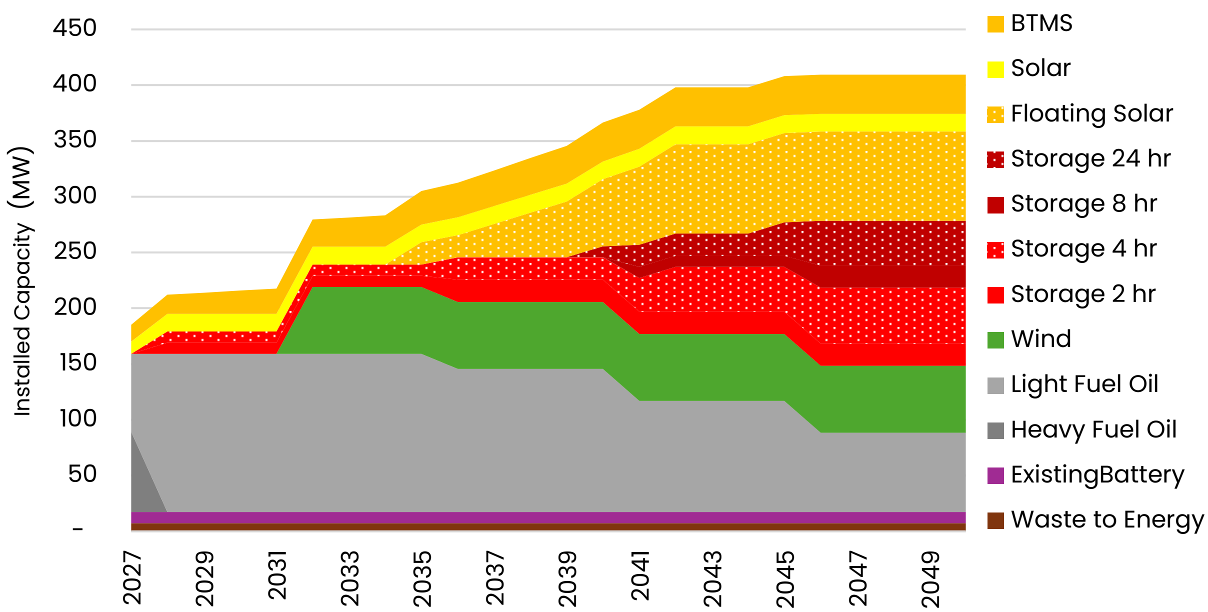


Figure 36: Energy Output of P2L (Affordability & LFO)

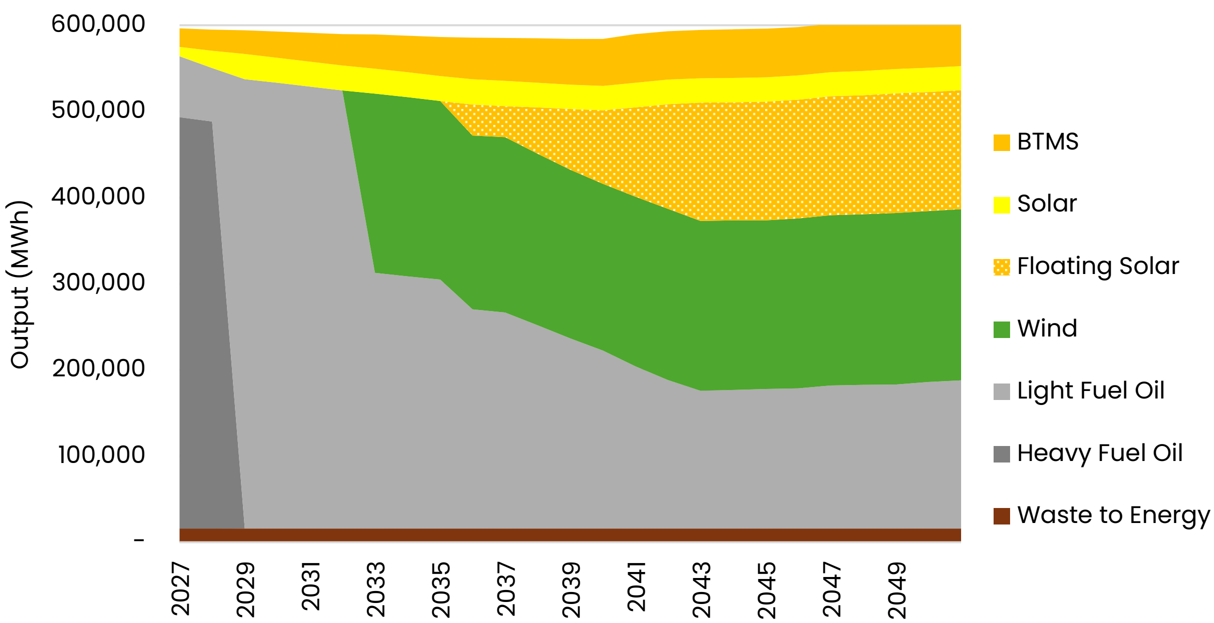


Figure 37: Installed Capacity of P2LL (Affordability & LFO-LCU)

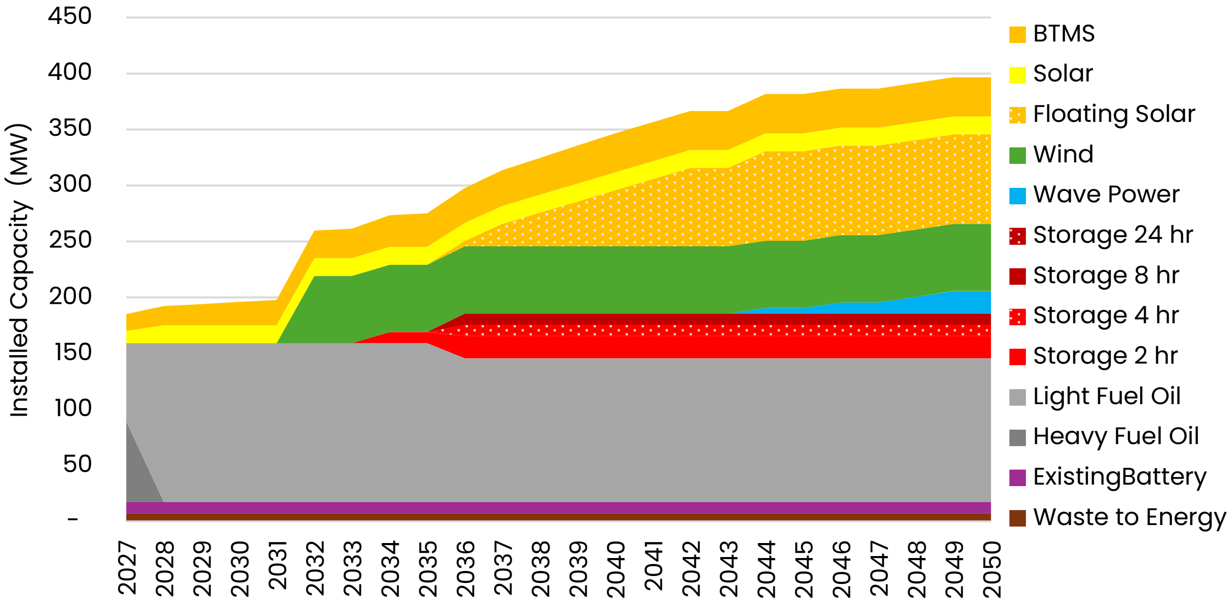


Figure 38: Energy Output of P2LL (Affordability & LFO-LCU)

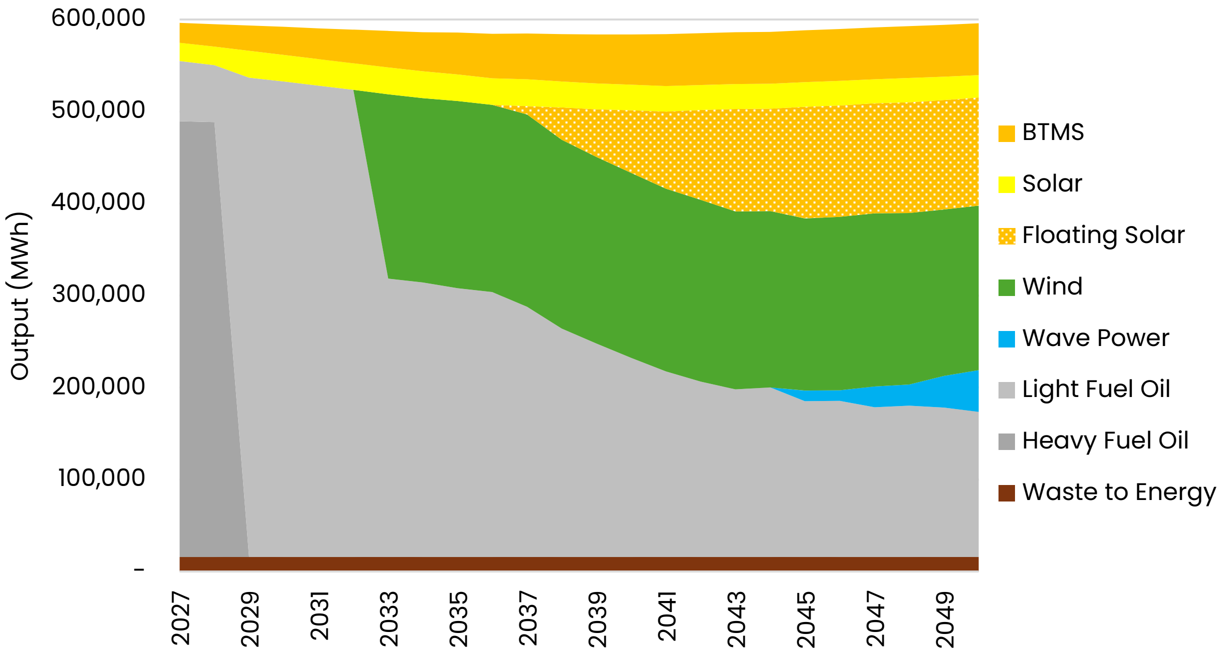


Figure 39: Installed Capacity of P2N (Affordability & LNG)

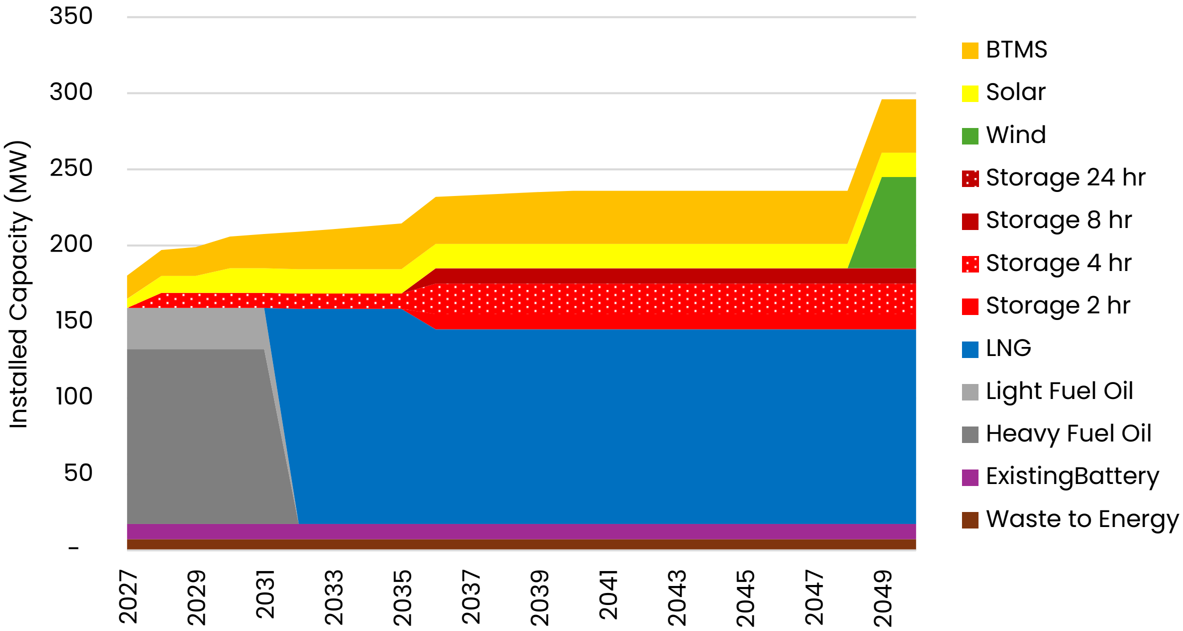


Figure 40: Energy Output of P2N (Affordability & LNG)

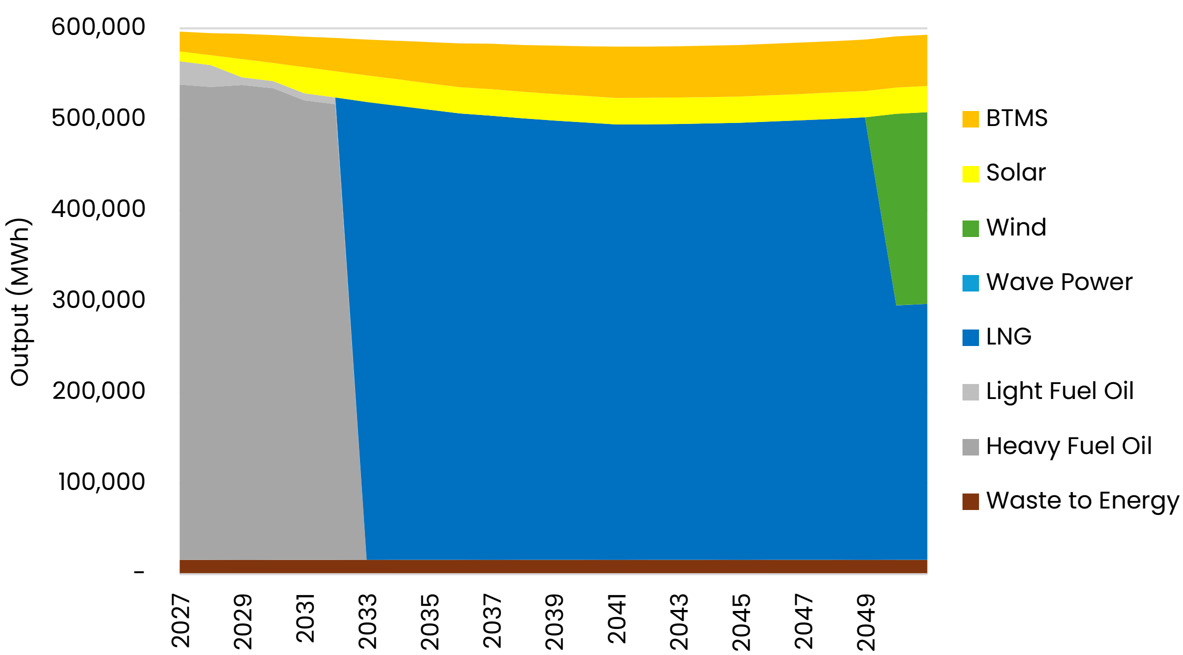


Figure 41: Installed Capacity of P4N (50% Renewable Generation & LNG)

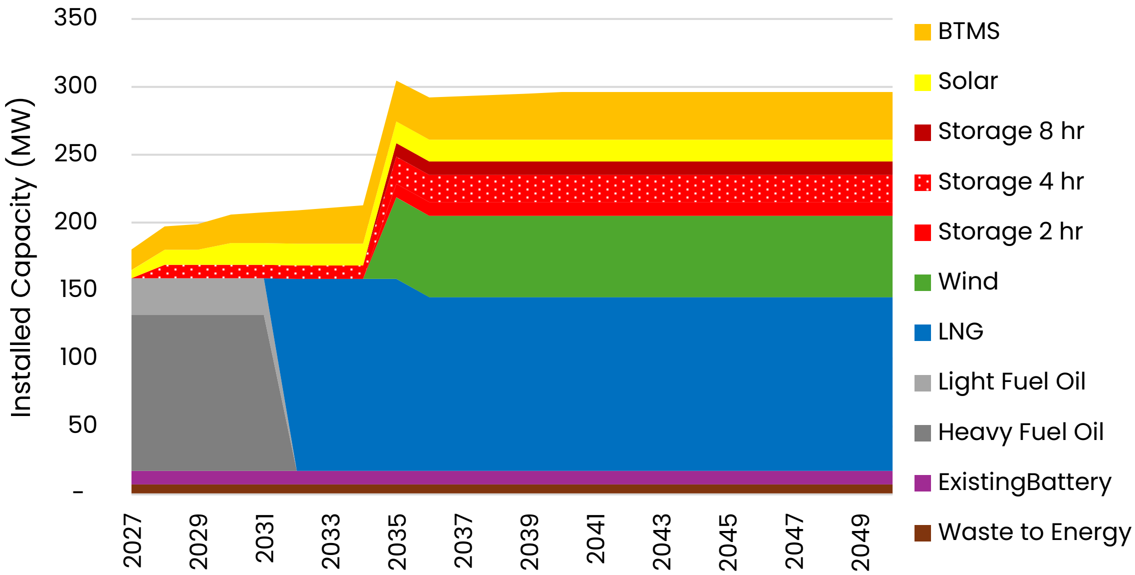


Figure 42: Energy Output of P4N (50% Renewable Generation & LNG)

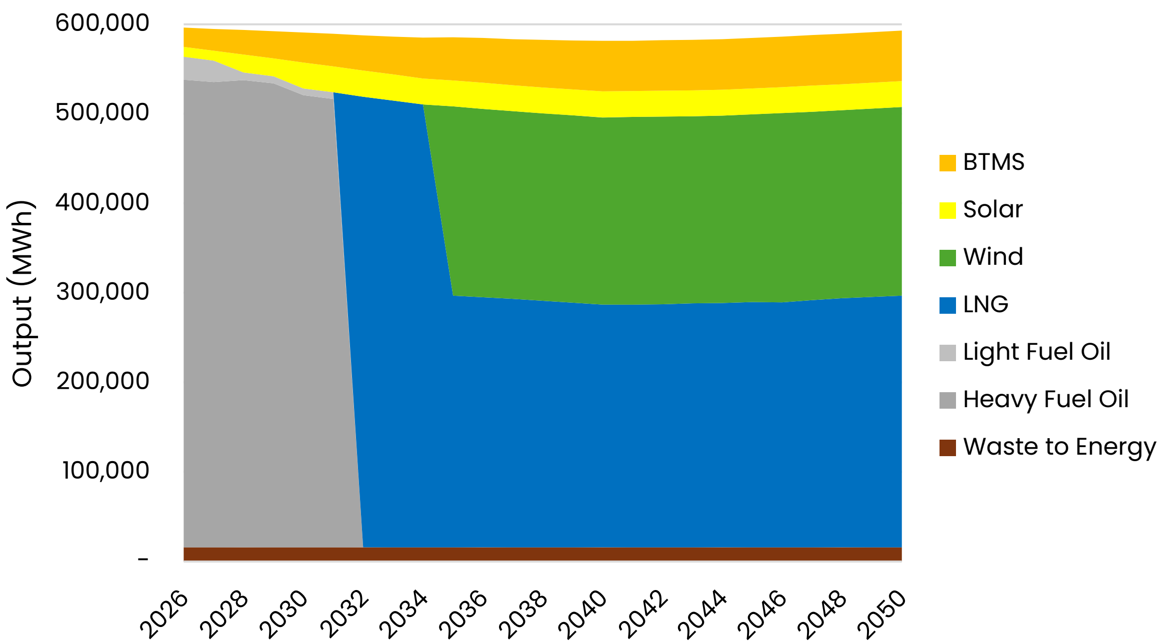


Figure 43: Installed Capacity of P2LM (Methanol)

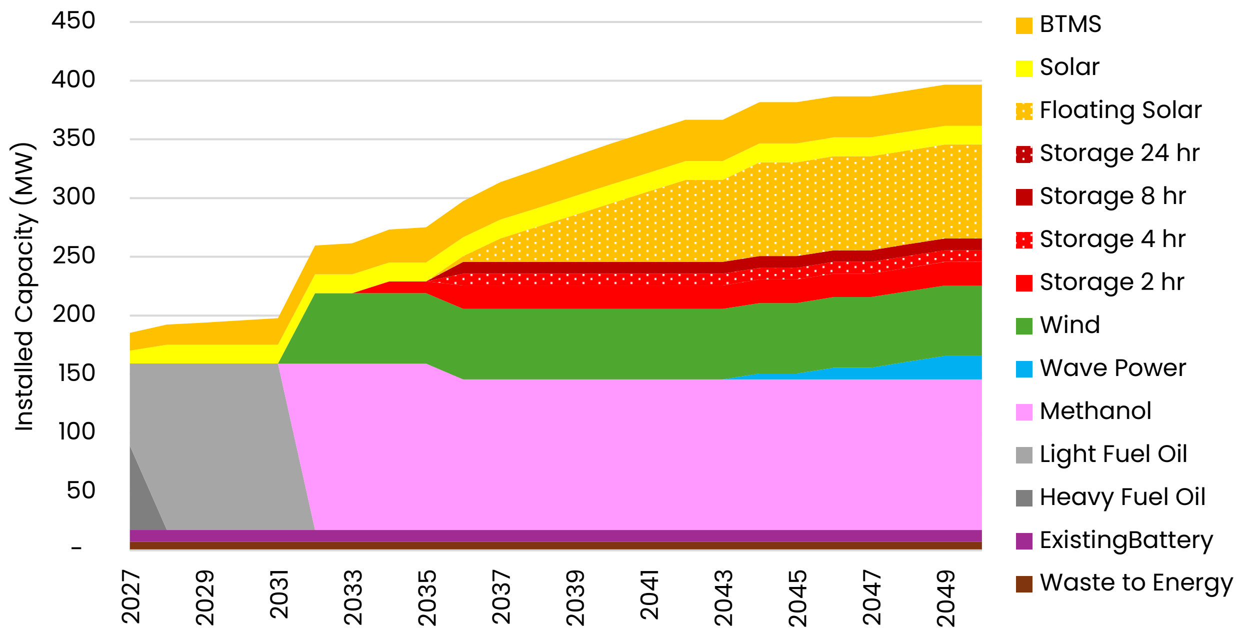
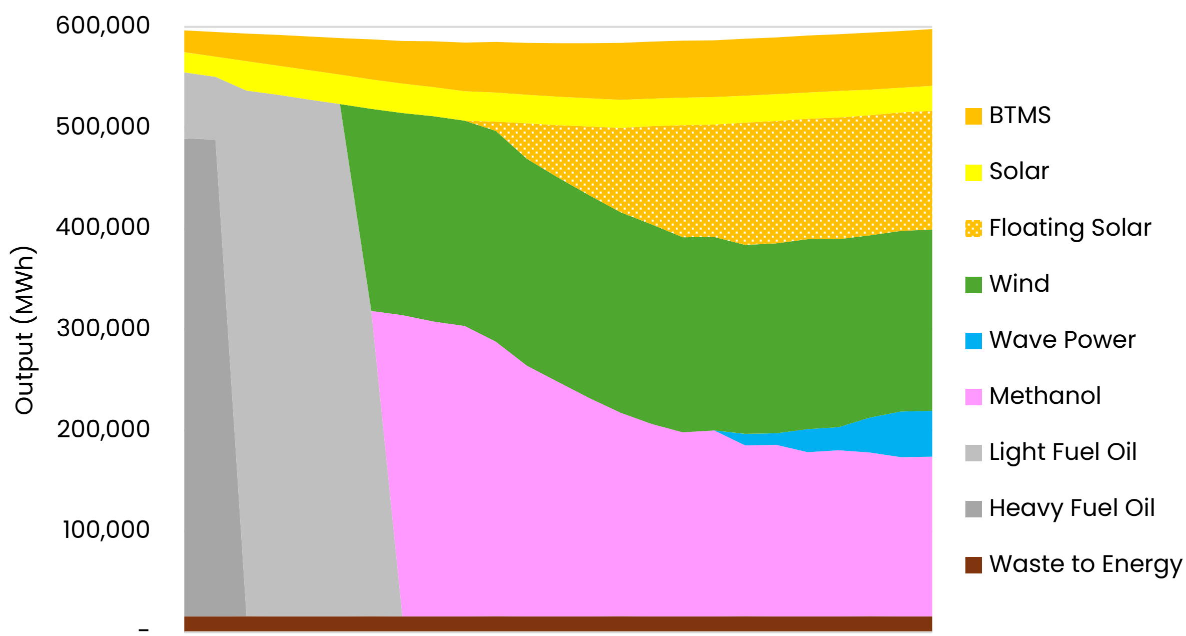


Figure 44: Energy Output of P2LM (Methanol)



APPENDIX H – RESILIENCY, RELIABILITY AND STABILITY STUDIES

Reliability is built into the model as a constraint. The system is required to meet a reserve to maintain the system loss of load event (LOLEv) target of "1-day-in-10-years." Or the system can experience a loss of firm load of any magnitude or for any duration less than one day every ten years, on average. When capacity expansion for each model was complete, if the system did not meet this target, portfolios were adjusted to maintain this minimum reliability.

H.1 Operating Reserves

Operating reserves are generation that is not currently being used to meet demand but can, in a short amount of time, become available in the case of an unplanned event on the system, such as a loss of generation or when real-time demand is higher or lower than forecast. This generation can be from generators that are synchronised (connected) to the power grid or offline and from certain loads, designated as demand-side response, which can be removed from the grid. The characterisations of different operating reserves terminology and definitions can be found in Table 34.

Table 34. Operating Reserve Service Definitions[30]

Name	Use	Response Speed	Other Names
Operating Reserve	Any capacity is available for assistance in active power balance.	Seconds to 10 minutes	
Regulating Reserve	Capacity available during normal conditions for assistance in active power balance to correct any system imbalance that occurs.	Second to 1 minute	Regulation, load frequency control, secondary control
Contingency Reserve	Capacity available for assistance in active contingency power balance during infrequent events that are more severe than balancing needed during normal conditions and are used to correct instantaneous imbalances.	Seconds to 10 minutes	(Spinning and non-spinning reserve)
Spinning Reserve	Online capacity, synchronised to the grid, that can increase output in response to a major generator or transmission outage.	Seconds to 10 minutes	Synchronised Reserve
Non-Spinning Reserve	Offline capacity that can be brought online after a short delay in response to a major generator or transmission outage.	Seconds to 10 minutes	Quick start Reserve

30 Ela, E., Milligan, M., & Kirby, B. (2011). Operating reserves and variable generation (No. NREL/TP-5500-51978). National Renewable Energy Lab. (NREL), Golden, CO (United States).

H.2 Contingency Reserve: GT5

GT5 currently meets the TD&R Licensee's contingency reserve. The unit carries non-spin reserves to supplement the primary spinning reserves carried by other resources. The existing GT5 will be replaced with more efficient gas turbines that will be available to provide non-spin reserves to and supplement the primary spinning reserves on the system.

In the model, GT5 and its replacements are treated as contingency reserve, generating energy to manage instances of capacity shortfall over a significant period, which can result in load shedding.

H.2.1 Planning reserves

Planning reserves are estimated based on the Planning Reserve Margin (PRM) requirement, which is the amount of capacity required to reliably meet expected demand over the forecast period.[31] While operating reserves are used in the shorter-term to respond to an unplanned event on the system, planning reserves are used in the longer term to ensure adequate power supply given a forecasted load in the years ahead.

The TD&R Licensee is required to carry adequate generating capacity to maintain reliability for Bermuda, in accordance with the EA. This additional capacity is necessary to mitigate against the uncertainty in the peak load. Uncertainty in peak load can be due to weather or forecast error.

In addition, each portfolio must have sufficient capacity to accommodate two or more generators in the system going offline due to unplanned failure or planned maintenance. Given the isolated island nature of its system, the grid must have sufficient capacity to safely operate without the two largest generators. This equates to 28.8 MW currently.

Historically BELCO has taken a more deterministic approach to determining the planning reserve margin, is shown below.

$$\begin{aligned} PRM(MW) = {} & dependable\ capacity\ of\ the\ two\ largest\ traditional\ generating\ resources \\ & + the\ dependable\ capacity\ of\ the\ WTE\ plant \\ & + the\ dependable\ capacity\ of\ the\ utlity\ scale\ solar \\ & + the\ aggregate\ dependable\ capacity\ of\ BTM\ solar \end{aligned}$$

As Bermuda moves towards a renewable and diverse energy mix, traditional planning methods must reflect a more probabilistic approach that considers statistical demand and weather patterns as well as the capacity contribution of variable and dispatchable resources. The TD&R Licensee has targeted a "1-day-in-10-years" reliability target, which is a standard reliability target across many utilities. The capacity needed to meet this target and accommodate planned and unplanned outages represents the total reliability need (TRN). From this total required capacity, the PRM can be determined as the required generation capacity available

[31] NERC Reliability Indicators.

above peak system load to meet the reliability target. Often this is represented as a percentage of the peak demand forecast as shown below.

$$PRM(\text{percent}) = \frac{Total\ Reliabilty\ Need - Peak\ Demand}{Peak\ Demand}$$

The annual peak demand is unknown and must be forecasted based on load shape and load growth. Generally, the load shape exhibits seasonal, weekly, and daily periodic behaviour and will change over time due to technological and economic factors. The exact load depends on the weather, time of day, day of the year, and consumer behaviour. All these factors impact the time at which peak load occurs as well as the magnitude of the peak load. These factors must be considered when determining the PRM required to maintain reliability. The resulting PRM needed to meet the desired reliability target and accommodate N-2 security is reported in Table 35.

Table 35: Planning Reserve Margins

Year	PRM (%)	PRM (MW)
2024	39%	38.5
2025	40%	38.3
2026	40%	39.8
2027	40%	40.5
2028	40%	39.8
2029	40%	39.6
2030	40%	39.5
2031	40%	39.5
2032	40%	39.4
2033	40%	39.4
2034	40%	39.3
2035	40%	39.3
2036	40%	39.2
2037	40%	39.2
2038	40%	39.2
2039	40%	39.2
2040	41%	40.1
2041	41%	40.1
2042	41%	40.1
2043	41%	40.0
2044	41%	40.0
2045	41%	40.0
2046	41%	40.0
2047	41%	39.9
2048	41%	39.9
2049	41%	39.9
2050	41%	39.9

H.2.2 Effective Load Carrying Capacity (ELCC)

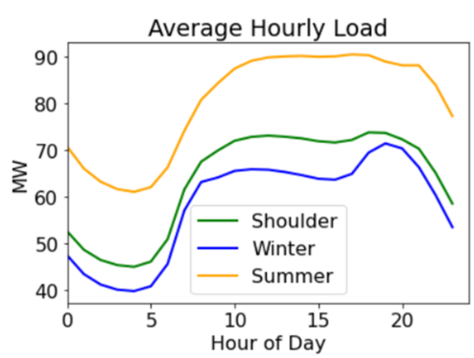
No generating resource is 100% reliable. Variable generators depend on the weather and thermal resources may experience forced outages. The ELCC was used to capture each resource's contribution towards meeting the PRM. The ELCC of a resource represents the required amount of "perfect" generating capacity needed to replace the imperfect resource while maintaining the same reliability.

It is important to note that the ELCC is not equivalent to the capacity factor (CF) of a resource. The CF is also on a zero to one scale representing the average power production of a resource, normalised by the installed capacity. In many cases, the ELCC will be lower than the CF since it focuses on a resource's contribution during periods of grid stress. When computing ELCC values, it is important to capture the shifting time of peak net load and the impact of the installed capacity on the ELCC. Interactions between technology types must be considered because they can have antagonistic or synergistic effects.

The ELCC for each technology is computed at varying installed capacities. These are reported for the summer, winter, and shoulder seasons. The ELCC is computed as the amount of "perfect" capacity that could be replaced while maintaining the same reliability. A sample of the seasonal ELCC values, as a function of installed capacity, is shown in Figure 46.

The average hourly seasonal loads are shown in Figure 45. These load shapes are useful in understanding the ELCC trends. The summer load is flat during the daytime hours. Thus, a resource would have to cover all high-load hours to achieve a high ELCC. In contrast, a resource needs only cover the evening peak in the winter to achieve a high ELCC. Wave and wind have the greatest potential for contribution in the winter and shoulder months, with lower contribution in the summer since they have lower summer output. The solar ELCCs have high summer values but do not contribute to winter or shoulder reliability since the peak load occurs after the sun has set during these seasons. There is a sharp decline of the solar ELCC with additional capacity since solar generation quickly shifts the peak net load after the sun has set. There are also significant synergies between all renewables and storage, particularly solar, since storage allows the energy generated by the renewable resource to be shifted to the greatest time of need. Wind, wave, and solar energy complement each other as they each have different resource patterns.

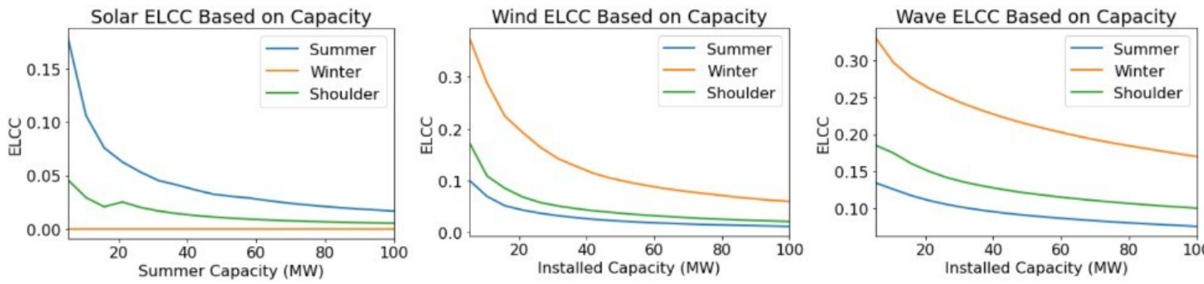
Figure 45. Average Seasonal Hourly Load



The computation of an ELCC value for battery storage is more challenging. The reliability impact of a storage asset is a function of both the technical properties of the battery and the decision on how to charge and discharge the battery. Batteries are used to minimise the peak daily load, using the average daily load profile for each season (Figure 46).

Computing the ELCC value for thermal resources is more straightforward since their output is controllable. The ELCC value for these thermal resources is one minus the forced outage rate.

Figure 46. Seasonal ELCC Values for Renewable Resources



H.2.3 Ensuring Adequate System Flexibility

The second component of reliability is flexibility. This means having sufficiently flexible dispatchable generating resources to meet any changes in net load (gross load less renewable). If the conventional resources are not sufficiently flexible, the grid could experience load-shedding events due to sharp changes in net load. This will become increasingly important as the portion of renewables increases, since such increases can induce sharp changes in net load. Some utilities have required additional ramping reserves to ensure that there are sufficient fast resources to counter these challenges. These potential flexibility challenges are of interest to Bermuda to achieve high levels of decarbonisation while maintaining reliability. However, Bermuda is well-positioned to meet these challenges presently and into the future. The existing dispatchable generating resources and the potential future resources considered in this IRP are highly flexible. Bermuda requires a flexible resource mix to accommodate the variability and uncertainty of intermittent renewables. While these reserves are not explicitly modelled, the ability of future resources to ramp up or serve as commitment units from an offline state should adequately cover this requirement.

H.3 Assessing the reliability of a proposed portfolio (Loss of Load Analysis)

BELCO’s 2026 IRP Refresh evaluates each candidate resource portfolio’s reliability through a robust probabilistic loss of load analysis, using sequential Monte Carlo simulations to examine hundreds of plausible future scenarios. These simulations are the primary way to measure metrics like LOLE and EUE, capturing uncertainties in weather-driven demand, renewable output, and random outages. However, these simulations alone may not fully capture certain low-probability yet high-impact events – particularly in an island context where historical data is limited and probabilities for extreme events are hard to quantify. For example, an extended forced outage of a critical generator requiring a replacement part from overseas, or a common-cause failure (such as a hurricane damaging multiple units at once), could present severe challenges to Bermuda's grid despite being rare. Mainland systems have experienced analogous correlated stresses (as illustrated by Winter Storms Uri and Elliott,[32] where extreme cold weather caused many thermal generators to fail simultaneously), but in Bermuda such events cannot easily be assigned a meaningful probability because they have little or no precedent. Given these limitations, BELCO's IRP augments its probabilistic loss of load analysis with deterministic "stress-check" scenarios to test how each portfolio would withstand credible but extreme conditions.

Additionally, since the 2023 IRP proposal, this model has been updated to better represent maintenance outages. These outages are distributed across the months with lower load levels.[33]

The simulation covers the period roughly 2025 through 2050, drawing on roughly 100 distinct "weather-year" scenarios derived from historical climate patterns (with synthetic variability added to broaden the range). Each scenario is run through a chronological hourly dispatch model, which means the model mimics the hour-by-hour operation of the grid – including battery charge and discharge cycles – so that energy-limited resources and operational constraints are properly represented. In each simulated future, generation resources are committed and dispatched in merit order to meet load, and any shortfalls (periods when available capacity cannot fully meet demand) are recorded along with their magnitude and duration. No fixed planning reserve buffer is assumed in these simulations; instead, the model effectively pushes each portfolio to its limits during peak conditions, which better captures how the system would perform during extreme events. The output of this analysis is a set of standard reliability metrics – notably the Loss of Load Expectation (LOLE), which measures the expected number of days per year on which shortfalls (if any) occur. This is the primary planning standard for resource adequacy across North America, traditionally set at 0.1 days/year, equivalent to the "1-day-in-10-years" reliability criterion. Additional metrics such as Loss of Load Hours (LOLH), Loss of Load Probability (LOLP), and Expected Unserved Energy (EUE) are also computed to characterize any residual reliability risk in terms of event frequency, duration, and energy not served. The definition and widely accepted targets for of each of the risk metrics in Table 36. They give an important indication of each portfolio's reliability under typical grid conditions. However, they do not fully capture the impact of low-probability yet

[32] Federal Energy Regulatory Commission and North American Electric Reliability Corporation. "FERC, NERC Release Final Report on Lessons from Winter Storm Elliott." News release, November 7, 2023. https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott.

high-impact events; as such, portfolios will have to exceed the typical mainland targets to withstand all rare, but credible events.

Table 36. Risk Metric Definition

Metric	Name	What It Measures	Typical Planning Target
LOLE	Loss of Load Expectation	The expected number of days per year in which load shedding occurs, regardless of the size or duration of the event. This metric captures the *frequency* of reliability shortfalls.	0.1 days per year (equivalent to one day in ten years)
LOLH	Loss of Load Hours	The total expected number of hours per year during which load shedding occurs, regardless of magnitude. This metric captures the *duration* of reliability shortfalls.	2.4 hours per year
LOLP	Loss of Load Probability	The probability that load shedding occurs in any given hour. This metric is typically derived from LOLH and reflects the *likelihood* of an outage in an any given hour.	Approximately 0.027% (2.4 hours ÷ 8,760 hours)
EUE	Expected Unserved Energy	The total amount of unserved energy in a year, typically expressed in megawatt-hours and normalized as a percentage of total annual energy demand. This metric captures the *magnitude* of reliability shortfalls.	10–20 ppm (approximately 0.001–0.002% of annual energy not served

The results indicate that overall reliability is strong across most of the portfolios, with some year-to-year variation in the early years driven by Monte Carlo numerical noise rather than material changes in the portfolios.

In the initial years, P2LL and P2F show LOLE values slightly above the tolerance, although EUE remains below the target. This indicates that the exceedances are driven by short, shallow events rather than large reliability failures and appear to be associated primarily with maintenance timing. These outages are driven primarily during maintenance events and emphasize the need for careful maintenance planning. P2L and P2N perform somewhat better in the early years, reflecting the benefit of their initial build-out.

In the mid-years, all portfolios appear broadly robust and show similar reliability performance under both the probabilistic analysis and the stress tests. Outage events remain infrequent, short in duration, and relatively limited in size.

The main divergence occurs in the out-years, where P2F shows a material deterioration in reliability. It exceeds both the EUE and LOLE targets, and outages become larger and longer. The stress results show the same pattern, indicating that the portfolio is increasingly vulnerable to prolonged energy shortfalls. This suggests that, in a more renewable system, BELCO's credible N-2 risk may increasingly be driven by event duration rather than instantaneous capacity loss. A battery-forward portfolio such as P2F therefore appears to require additional energy-generating resources to remain robust in the out-years.

The other portfolios remain more robust in the out-years and appear to benefit from greater fuel and technology diversity. This suggests that BELCO may ultimately need to refine how it defines credible N-2 events in a more decarbonized system.

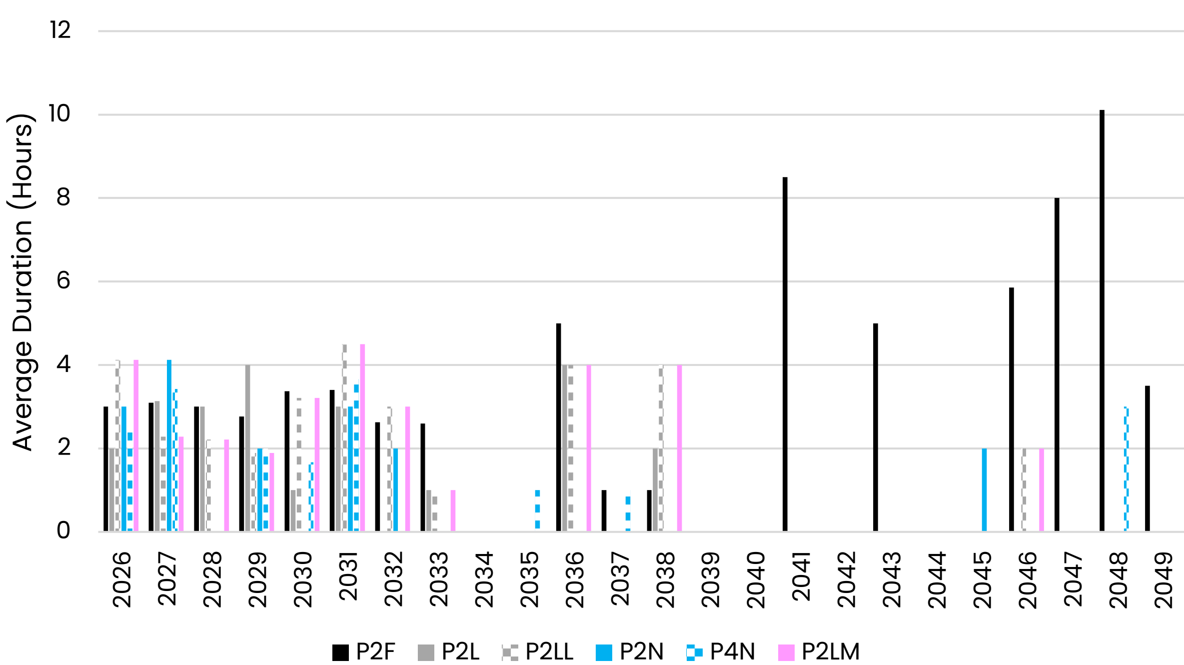
Table 37: Loss of Load Expectation for Proposed Portfolios.

	P2F	P2L	P2N	P2LL	P2N	P4N	P2LM
2026	0.022%	0.005%	0.014%	0.025%	0.014%	0.016%	0.025%
2027	0.049%	0.036%	0.022%	0.019%	0.022%	0.016%	0.019%
2028	0.038%	0.005%	0%	0.038%	0%	0%	0.038%
2029	0.047%	0.003%	0.011%	0.025%	0.011%	0.008%	0.025%
2030	0.022%	0.003%	0%	0.049%	0%	0.011%	0.049%
2031	0.027%	0.008%	0.003%	0.005%	0.003%	0.008%	0.005%
2032	0.022%	0%	0.003%	0.005%	0.003%	0%	0.005%
2033	0.014%	0.003%	0%	0.003%	0%	0%	0.003%
2034	0%	0%	0%	0%	0%	0%	0%
2035	0%	0%	0%	0%	0%	0.005%	0%
2036	0.003%	0.008%	0%	0.003%	0%	0%	0.003%
2037	0.003%	0%	0%	0%	0%	0.003%	0%
2038	0.005%	0.003%	0%	0.003%	0%	0%	0.003%
2039	0%	0%	0%	0%	0%	0%	0%
2040	0%	0%	0%	0%	0%	0%	0%
2041	0.008%	0%	0%	0%	0%	0%	0%
2042	0%	0%	0%	0%	0%	0%	0%
2043	0.003%	0%	0%	0%	0%	0%	0%
2044	0%	0%	0%	0%	0%	0%	0%
2045	0%	0%	0.003%	0%	0.003%	0%	0%
2046	0.068%	0%	0%	0.003%	0%	0%	0.003%
2047	0.033%	0%	0%	0%	0%	0%	0%
2048	0.055%	0%	0%	0%	0%	0.003%	0%
2049	0.019%	0%	0%	0%	0%	0%	0%

Table 38: Expected Unserved Energy (MWh) for Proposed Portfolios

	P2F	P2L	P2N	P2LL	P4N	P2LM
2026	1.0	0.1	1.2	2.6	0.7	2.6
2027	4.0	2.8	2.2	0.6	1.7	0.6
2028	2.2	0.3	0	1.6	0	1.6
2029	2.6	0.2	0.4	0.7	0.2	0.7
2030	1.4	0	0	3.6	0.4	3.6
2031	2.9	0.5	0.2	0.6	0.4	0.6
2032	1.3	0	0	0.4	0	0.4
2033	0.7	0.1	0	0.1	0	0.1
2034	0	0	0	0	0	0
2035	0	0	0	0	0	0
2036	0.2	1.1	0	0.3	0	0.3
2037	0	0	0	0	0.1	0
2038	0.1	0.1	0	0.5	0	0.5
2039	0	0	0	0	0	0
2040	0	0	0	0	0	0
2041	8.1	0	0	0	0	0
2042	0	0	0	0	0	0
2043	0.4	0	0	0	0	0
2044	0	0	0	0	0	0
2045	0	0	0	0	0	0
2046	24.6	0	0	0.2	0	0.2
2047	12.9	0	0	0	0	0
2048	38.4	0	0	0	0.1	0
2049	2.5	0	0	0	0	0

Figure 7. Expected Duration of Outages



H.4 Resilience Assessments

Given the limitations of the loss of load analysis discussed in the previous section, we include additional resilience assessments to test each portfolio against rare but credible stress events. These events are not assigned explicit probabilities in the Monte Carlo analysis, but they represent plausible conditions that could materially challenge an island system. Specifically, we test prolonged outages of the largest thermal unit under alternative maintenance assumptions, as well as a 14-day wind and solar disruption intended to represent a severe renewable shortfall during an extreme weather event. The percentages reported below reflect the share of simulated outcomes in which load shedding occurs under each stress condition, providing a practical measure of each portfolio's ability to withstand low-probability, high-impact disruptions.

Initially, P2F and P2L are sensitive to long-duration thermal outage events if maintenance occurs. This reflects the realities of island systems—a single thermal outage would result in a materially tighter system. The other portfolios benefit from initial system build outs. During the medium-term years, the system reflects strong resilience because the grid benefits for investment in a diversity of fuels sources.

However, after 2047, the systems diverge substantially. The P2F portfolio is highly susceptible to any fluctuation in the grid, particularly long-duration events. Similarly, the P2L portfolio is susceptible to long-duration renewable outages. These results highlight that BELCO's definition of N-2 will likely need to evolve in a portfolio with deep decarbonization and will likely need to include an element of duration of events.

Table 39: Resiliency Tests for Study Year 2030.

Scenario	**P2F**	**P2L**	**P2N**	**P2LL**	**P4N**
Largest thermal unit out for full year (maintenance allowed for other thermals)	32%	2%	7%	38%	2%
Largest thermal unit out for full year (maintenance not allowed for other thermals)	11%	0%	1%	13%	2%
Wind and solar outage for 14 days	1%	0%	0%	1%	1%

Table 40: Resiliency Tests for Study Year 2035.

Scenario	P2F	P2L	P2N	P2LL	P4N
Largest thermal unit out for full year (maintenance allowed for other thermals)	4%	0%	0%	1%	0%
Largest thermal unit out for full year (maintenance not allowed for other thermals)	0%	0%	0%	0%	0%
Wind and solar outage for 14 days	0%	0%	0%	0%	0%

Table 41: Resiliency Tests for Study Year 2040.

Scenario	P2F	P2L	P2N	P2LL	P4N
Largest thermal unit out for full year (maintenance allowed for other thermals)	0%	0%	0%	0%	0%
Largest thermal unit out for full year (maintenance not allowed for other thermals)	0%	0%	0%	0%	0%
Wind and solar outage for 14 days	0%	0%	0%	0%	0%

Table 42: Resiliency Tests for Study Year 2047.

Scenario	P2F	P2L	P2N	P2LL	P4N
Largest thermal unit out for full year (maintenance allowed for other thermals)	51%	0%	0%	0%	0%
Largest thermal unit out for full year (maintenance not allowed for other thermals)	22%	0%	0%	0%	0%
Wind and solar outage for 14 days	93%	86%	0%	0%	0%

H.5 Resource Diversity (Technology Concentration)

Technology concentration ensures the system does not rely too heavily on a resource to hedge against global pressures such as volatility on commodity pricing, technology costs, or supply chain issues.

Technology concentration uses the HHI which is a widely used metric to measure concentration in markets.[34] The HHI is calculated with the following formula, where s = share of a given resource in installed capacity in percent:

$$HHI = \frac{\sum s^2}{100^2}$$

A higher HHI value implies the system has technologies concentrated in fewer types of resources, and a lower HHI implies higher system diversity. Portfolios with high HHI are more at risk of not meeting load if a technology does not materialise on the island. On the other hand, portfolios with greater diversity can rely on a wider range of resource types if there are construction delays, inability to procure a resource by a certain date, or other execution risks.

Technology concentration is especially important to hedge against any global pressures or supply chain disturbances that cannot be predicted. Diversifying the fleet allows the island to meet demand even when fuel shortages prevent units from running or supply chain issues affect OSW. Adding more types of generation resources may also reduce the dependence on emissions-intense generation to hedge against renewable intermittency.

The economic portfolios have less diverse buildouts compared to the carbon-constrained cases because there are not stringent renewable targets that require additional renewable resources. Some portfolios such as P2LL and P4N have lower overall system capacity despite the same types of resources, which leads to a slightly lower HHI compared to P2L or P2N, respectively.

H.6 Stochastic Loss-of-Load Methodology

To thoroughly assess the resource adequacy of the potential portfolios, BELCO conducted a stochastic (probabilistic) loss of load analysis for each candidate 2026 IRP portfolio. This analysis was performed using a sequential Monte Carlo simulation framework with chronological hourly dispatch, designed to capture the dynamic interplay of load, generation availability, and energy-limited storage behaviour in each hour. The simulation spanned the entire planning horizon (approximately 2025–2050), evaluating resource adequacy in each year of that period. For each portfolio, the model generated a large number of possible future states (on the order of 100 distinct annual scenarios), each representing a plausible combination of weather, demand, and outage conditions.

These scenarios were derived from historical weather records and synthetic variations, thereby preserving realistic seasonal load shapes and renewable output patterns while introducing statistical randomness to reflect the inherent uncertainty and variability from year to year. By basing the load, wind, and solar time series on historical conditions (with adjustments for expected long-term trends), the Monte Carlo engine simulates both typical patterns and

[34] Concentrating on Technology, S&P

extreme events (e.g. unusually hot summers or extended low-wind periods), ensuring the portfolios are stress-tested against a wide range of possible conditions.

The resulting range of load, wind, and solar outcomes are shown in Figure 47, Figure 48 and Figure 49. The load shocks capture the annual and daily shaping trends, as well as capturing the hourly and weekly trends. The wind and solar shocks capture seasonal and daily trends. The wind shapes have more substantive uncertainty, while the solar shape is relatively predicable.

This probabilistic approach provides a richer picture of reliability risk than a single deterministic case: instead of predicting exactly when or if a shortfall will occur (an impossible task), it quantifies the likelihood and severity of potential loss-of-load events under many different futures. However, it does not capture very rare, but credible events that are difficult to quantify.

Figure 47: Load Shaping Uncertainty

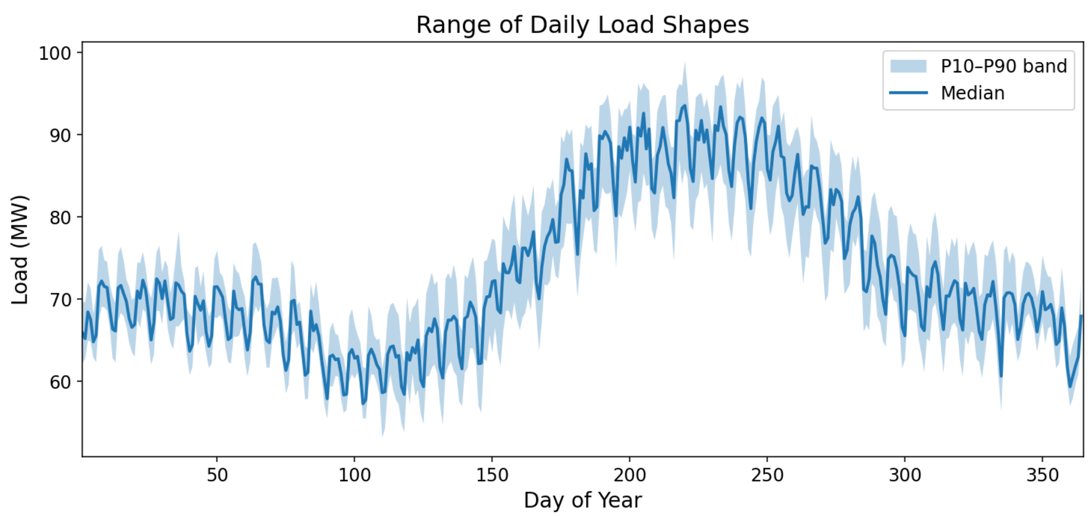


Figure 48: Wind Shaping Uncertainty

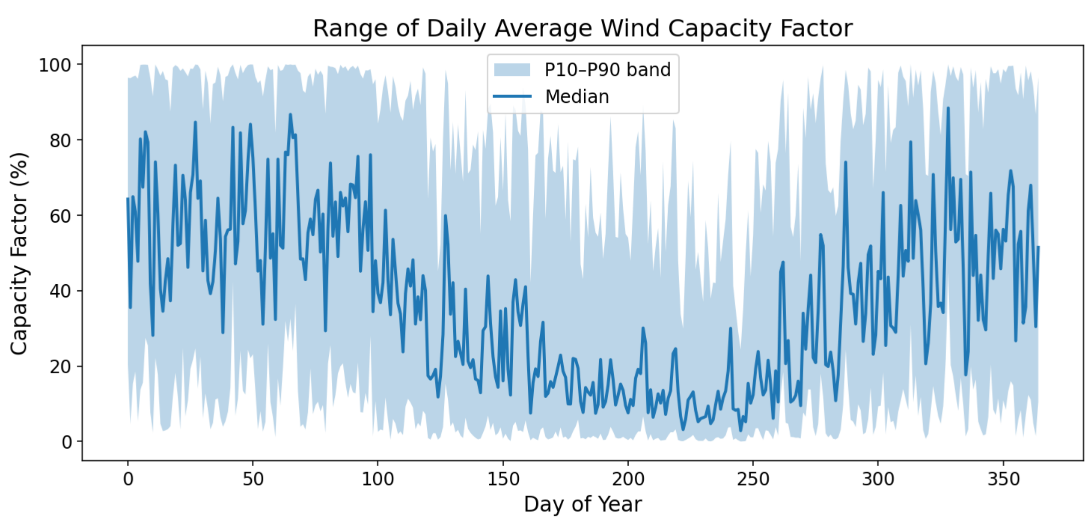
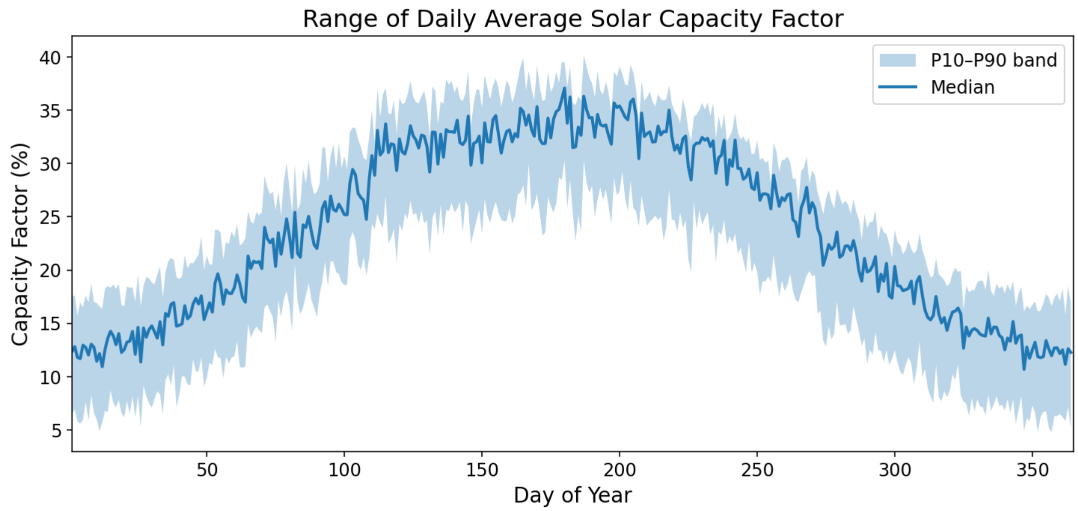


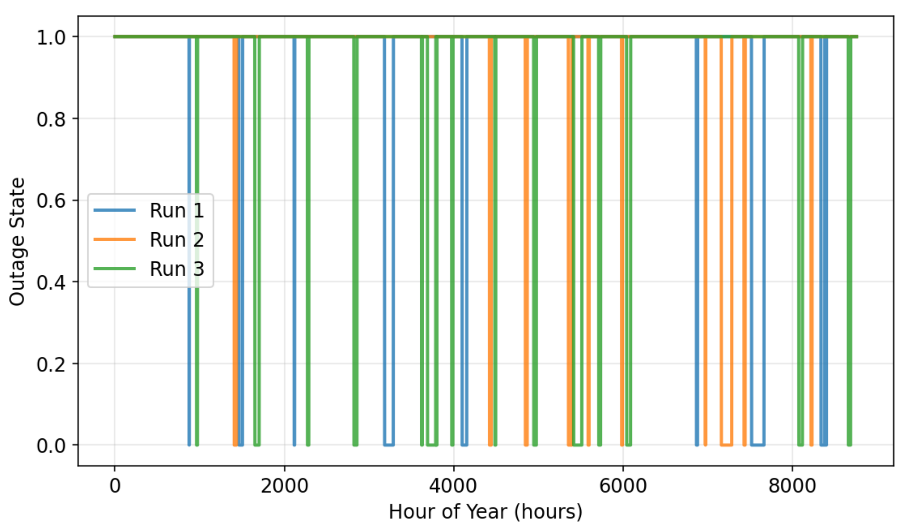
Figure 49: Solar Shaping Uncertainty



H.7 Simulation of Generator and Storage Availability

The loss of load model explicitly incorporates random equipment failures and maintenance outages to assess how each portfolio would perform under realistic operating conditions. Conventional thermal units were assigned forced outage rates (EFORd) based on historical performance, and the simulation used a two-state Markov process (or equivalently, an exponential "mean time to failure / mean time to repair" model) to randomly generate forced outage events for each unit, including realistic durations and frequencies of unplanned outages. The mean time between failure and mean time to repair are assumed to be 952 and 48 hours, respectively. The samples of possible outage outcomes are shown in Figure 50. As seen in the figure, a generator is on for a period of time. Once it trips offline, it is off continuously for a period of time, simulating the time to repair. Lastly, the outages vary by simulation.

Figure 50: Sample of Outage Outcomes



Planned maintenance outages were also scheduled in the simulations, outside of peak seasons, to reflect the need to occasionally remove units from service for upkeep. Maintenance is scheduled in all months except June, July, August, and September (i.e., peak demand months). Maintenance is scheduled in a manner that minimizes the capacity of generation out for service. The maintenance rate is assumed to be 10%. This is slightly below the maintenance rate of 12.7% assumed in Aurora modelling to reflect the ability to schedule some minor maintenance during low stress periods of time, but limited ability to shift major maintenance events that are scheduled weeks to months in advance. The maintenance events including the loss of load modelling reflects these major maintenance events.

Battery energy storage systems were modelled with equal rigor, treating them as energy-limited but dispatchable resources. This simulation aims to approximate a battery's behaviour during grid stress events, rather than day-to-day operation to minimize fuel costs. The simulation tracks each battery's state-of-charge continuously across hours and days. Charging and discharging decisions for the batteries are determined by an availability-based logic: at any given hour, if there is spare (unused) capacity from any other resource – whether renewable or thermal – the model assumes that energy will be stored (charging the batteries) rather than curtailed. Conversely, the batteries will discharge only when all other available generation (renewables and thermal plants) is already fully utilized and there is still residual unmet load. In this way, the modelling approach makes sure the contribution of storage during tight grid conditions is fully captured. To be conservative, the simulation also applies each battery's round-trip efficiency loss (e.g. ~80% efficiency, so that some energy is lost in each charge/discharge cycle) and even assumes that if a battery unit experiences a forced outage, any energy stored in it at that moment becomes unavailable (effectively a loss of that stored energy). This approach adds a layer of extreme stress to the simulation, representing a worst-case scenario for storage availability during critical periods. Overall, the chronological dispatch with integrated storage modelling ensures that operational constraints and energy limitations are respected, providing a realistic measure of each portfolio's performance in maintaining reliability.

H.8 Dispatch Logic for Reliability Assessment

It is important to note that the Monte Carlo simulation's dispatch and commitment algorithm emphasizes reliability over economics. The model commits and dispatches all available generation resources in order of priority (merit order) up to the level needed to meet demand (net of renewables), effectively mirroring how system operators would manage the grid during the most stressed conditions. In practice, system operators prioritizing reliability will bring online any and all resources as needed to avoid shortages, even if that means running units that are normally held in reserve or not economical under typical conditions. Similarly, batteries are kept charged whenever possible (using any surplus generation in real time) so that they can provide maximum support during a potential upcoming high-load or low-generation period.

This differs from typical day-to-day economic dispatch, where batteries might cycle regularly to minimize cost and thermal units might be held back for efficiency or cost reasons. Instead, the simulation's logic effectively assumes BELCO is operating in "all hands on deck" mode during potential shortfall conditions – an appropriate assumption for reliability analysis, as it intentionally examines each portfolio's weakest moments (when the system is under greatest strain and every available resource would be utilized).

By focusing on availability and maximum capability rather than cost optimization, the model captures a conservative estimate of reliability risk; if a portfolio can meet demand under this stress-test paradigm, it is likely to be reliable under real-world operations, where system operators have additional tools (like demand response and imports, if available) and economic triggers to help manage the system. Importantly, the model does not hold aside a separate "capacity reserve" for contingencies – because in a self-contained system like Bermuda's, all capacity is effectively needed to meet peak load plus an allowance for contingencies. Instead, the presence of fully charged batteries and the fact that some fast-start resources may be cycled off under normal conditions inherently provide a buffer. (In the simulation, any unused capacity in a given hour automatically goes into charging storage, which maintains system flexibility without explicitly reserving idle capacity.)

This stress-oriented logic ensures that reliability is measured in a worst-case sense, identifying whether and when shortfalls might occur even after using all portfolio resources to their fullest extent.

H.9 System Stability Study

Initial studies performed by a third-party for an example system in 2030 under minimum (night) and light (day) load conditions, the grid will experience frequency instability. Mitigation solutions will be further explored through more detailed studies.

The TD&R Licensee retained a third-party to perform grid stability studies under three system conditions – peak, day (light), and minimum (night) loading conditions for study years 2030 and 2043. Stability studies were performed to ensure that the system remained stable under conditions of high renewable generation and low load which are likely to manifest themselves after the 60 MW wind plant becomes operational. Stability is a general concern in all systems with loss of system inertia as inverter-based resources replace synchronous generation resources but particularly so in island systems with no external transmission support.

The system was projected to be stable under peak load conditions, however, frequency instability was observed for the other two cases. In the minimum thermal load case where wind generation is the highest and synchronous generation capacity is not online, the system experiences a frequency collapse. In the light(day) load conditions, the system is also unstable for certain faults. Instability is observed in the form of large rate of change of frequency events and/or frequency settling down to a value lower than nominal.

Additional analysis was performed to mitigate frequency instability events by backing off or curtailing wind generation and dispatching thermal generation. This leads to an improvement in frequency response. Further studies will be undertaken to analyse the ability of battery energy storage devices to provide the inertial response. Additional solutions might be to convert some of the retiring thermal generation into synchronous condensers. Such studies will require more sophisticated modelling tools that can simulate the very fast response of inverter controls.

It is recommended that the TD&R Licensee undertake detailed studies as soon as possible so that cost effective mitigation solutions can be identified. If battery energy storage devices are effective, procurement activity will need to specify the technical requirements for storage setting including potential need for grid forming inverters.

APPENDIX I – FINANCIAL MODEL ASSUMPTIONS

I.1 Financial Assumptions

The core financial assumptions used in the IRP are shown in Table 43. Note that the income tax rate for Bermuda is currently zero, and the land tax rate does not apply to this analysis.

Table 43. Financial Module Assumptions

Parameter	Value
Income Tax Rate	00%
Return on Equity	9.68%
Cost of Debt	5.50%
Equity % Rate Base	60%
Debt % Rate Base	40%
AFUDC	5.50%
Social Discount Rate	8.00%

I.1.1 Social Discount Rate

The social discount rate signals what future benefits and costs are worth today. [35] For the IRP, the social discount rate is used to derive the present value of future societal benefits and cost impacts in the assessment of the capital expansion plan. A lower discount rate tends to favour higher capital costs and lower operational costs, whereas a higher discount rate would prefer lower capital costs and higher operational costs. For the capacity expansion, a lower social discount rate favours new renewable builds with low operational costs.

Financial literature indicates a broad range of social discount rate values ranging from Treasury bond rates (5 percent) to as high as 10 percent. As future economic growth is uncertain, a rate closer to the mid-point (8 percent) was used.

[35] Discounting Future Benefits and Costs, EPA Guidelines https://www.epa.gov/sites/default/files/2017-09/documents/ee-0568-06.pdf

APPENDIX J - REVENUE REQUIREMENT ANALYSIS AND RESULTS

J.1 Overview of CRA's Financial Model

CRA's Financial Model projects utility revenue requirements by using inputs from Aurora (which include total variable power supply costs), capital expenditures associated with BELCO's fleet (new or existing), fixed operating and maintenance (FOM) costs, and financial accounting of depreciation, taxes, and utility return on investment. For the IRP, an annual revenue requirement was projected for the 2026 through 2050 period. The following sections describe in greater detail the key financial assumptions, financial accounting of BELCO's existing assets and replacement resources, and the overall approach for projecting customer rates.

J.2 Financial Model Calculation of Customer Rates

The Financial Model provides a projection of annual bundled customer rates on a cents per kilowatt-hour basis by dividing the total annual revenue requirement by the energy demand for that year. First-year rates generated from the Financial Model are baselined against actual BELCO rates (less RA fees, governmental fuel taxes, etc.) to validate the model. The annual revenue requirement is estimated from the bottom up by summing five key categories: Book Depreciation, O&M Expense, Return on Equity, Cost of Debt, and Taxes.

The Book Depreciation component includes depreciation expenses of existing resources, depreciation expenses of new resources, depreciation expenses of ongoing maintenance, and amortization. Assets will continue to depreciate in this model, even if they're retired early. It is assumed that the asset will remain in BELCO's possession until the end of the expected life, regardless of whether the asset is dispatched or not. As a result, stranded assets are not accounted for in any way aside from their continued depreciation.

The O&M Expense component can be broadly broken down into Variable O&M (VOM) expenses, Fixed O&M (FOM) expenses, and DSM costs. VOM expenses include those incurred during the normal operation of resources, including fuel costs, startup costs, and emissions costs. FOM expenses include those incurred regularly to maintain the operation of resources, including regular maintenance and labour. DSM costs represent those incurred by BELCO to deploy system-wide DSM programs to customers.

The Return on Equity and Cost of Debt components represent the financing costs required to operate the utility, including the financing of new resource construction and transmission upgrade projects.

The Taxes component includes any income and property taxes owed by the utility. BELCO has no income or property tax liability.

J.3 Financial Module Treatment of Existing Assets

Costs associated with existing resources are handled largely endogenously within the Financial Model. The Model takes as an input BELCO's starting rate base, inclusive of Bulk Generation

(BG); Transmission, Distribution, and Retail (TDR); and Other/Shared rate base components. The BG component of the rate base is largely comprised of BELCO's existing generating assets, including the East and North Power Stations and existing battery storage.

Forecasts of sustaining capital expenditures, routine maintenance costs, and depreciation expenses for BG, TDR, and Other/Shared assets are generated from BELCO's internal forecasting model and used as inputs to CRA's Financial Model. As each candidate portfolio is run through the Model, BG forecasts for sustaining capital expenditures and routine maintenance costs are adjusted to account for any early retirements, extensions, or upgrades of the East and North Power Stations, and the TDR forecasts are adjusted to account for any necessary transmission upgrades associated with switching to LNG as the primary fuel. Any sustaining capital expenditures are added to the rate base, and any routine maintenance costs are added to the O&M section of the revenue requirement build-up. Intermittent major repairs for BELCO's existing generating assets are amortized over three years and added to the Book Depreciation section of the revenue requirement build-up.

Other O&M costs associated with existing generating resources, including fuel costs and VOM expenses, depend on the dispatch schedule of each resource and are received as outputs from Aurora's standard zonal modelling. These costs are added to the O&M section of the revenue requirement build-up.

J.4 Financial Module Treatment of New Resources

As with existing resources, costs associated with new resources are handled largely endogenously within the Financial Model. Using the outputs from Aurora's capacity expansion modelling, the Financial Model incorporates the deployment schedule of new resources with the capital cost and FOM forecasts to calculate BELCO's annual capital expenditures and FOM expenses for new generating resources. For each new resource, an AFUDC adder is included in the annual capital expenditure total to arrive at the all-in capital cost, inclusive of funds used during construction. In the year that these resources enter service, their book values are added to the rate base and depreciated according to the serviceable lifetimes and their FOM expenses are added to the O&M section of the revenue requirement build-up.

Other O&M costs associated with new generating resources, including fuel costs and VOM expenses, depend on the dispatch schedule of each resource and are received as outputs from Aurora. These costs are added to the O&M section of the revenue requirement build-up.

APPENDIX K – ACRONYMS AND DEFINITIONS

AFDC	Alternative Fuels Data Centre
AFUDC	Allowance for Funds Used During Construction
AEO	Annual Energy Outlook
AMI	Advanced Metering Infrastructure
BAU	Business as Usual
BELCO	Bermuda Electric Light Company Limited
BELCO BG	BELCO in its capacity as a holder of a Bulk Generation Licence
BEV	Battery Electric Vehicle
BESS	Battery Energy Storage System
BG	Bulk Generation
BTM	Behind-the-Meter
BTMS	Behind-the-Meter Solar
BTU	British Thermal Unit
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CF	Capacity Factor
COD	Commercial Operation Date
CO_2 / CO_2e	Carbon Dioxide / Carbon Dioxide Equivalent
CRA	Charles River Associates (IRP Consultants)
DER	Distributed Energy Resource
DLC	Direct Load Control
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
EA	Electricity Act 2016
EE	Energy Efficiency
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capability
EPS	East Power Station
EV	Electric Vehicle
FIT	Feed In Tariff
GDP	Gross Domestic Product
GT	Gas Turbine
HCP	High Commodity Price (scenario)
HFO	Heavy Fuel Oil
HHI	Herfindahl–Hirschman Index
HVAC	Heating, Ventilation and Air Conditioning
ICAP	Installed Capacity
IRP	Integrated Resource Plan
ISO	International Organization for Standardization
KPI	Key Performance Indicator

LCE	Life Cycle Extension
LCOE	Levelised Cost of Energy
LCU	Life Cycle Upgrade
LFO	Light Fuel Oil
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LOLE	Loss of Load Expectation
LOLEv	Loss of Load Events
LPG	Liquefied Petroleum Gas
MW	Megawatt
MWh	Megawatt hour
NESP	National Electricity Sector Policy
NFP	National Fuels Policy 2018
NGCT	Natural Gas Combustion Turbine
NPS	North Power Station
NPV	Net Present Value
NPVRR	Net Present Value of Revenue Requirements
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturer
O&M	Operations and Maintenance
OpEx	Operational Expenditures
OSW	Offshore Wind
PEM	Proton Exchange Membrane
PHEV	Plug-in Hybrid Electric Vehicle
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PV	Photovoltaic
RA	Regulatory Authority of Bermuda
RA Guidance	Regulatory Authority's Integrated Resource Plan Guidance
RET	Renewable Energy Target
RFF	Resources for the Future
SDR	Social Discount Rate
T&D	Transmission and Distribution
TD&R	Transmission, Distribution and Retail
TD&R Licensee	BELCO in its capacity as the sole holder of a Transmission, Distribution, and Retail Licence
TDD	Technology Driven Decarbonisation (scenario)
TMY	Typical Meteorological Year
TOTEX	Total Expenditure
TRN	Total Reliability Need
VOM	Variable Operating and Maintenance
WTE	Waste to Energy

APPENDIX L - LIST OF FIGURES

APPENDIX M - LIST OF TABLES