2023 INTEGRATED RESOURCE PLAN

Pathways to a Net-Zero Electricity System

NEW BRUNSWICK
POWER CORPORATION

Énergie NB Power | the power of possibility
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Abbreviations

AECO	Alberta Energy Company
AC	Alternating Current
AGC	Automatic Generation Control
bbl	Barrels of Oil
BTM	Behind-the-Meter
CBOC	Conference Board of Canada
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CO_2e	Carbon Dioxide equivalent for greenhouse gas emissions
CT	Combustion Turbine
CPI	Consumer Price Index
DR	Demand Response
DSM	Demand Side Management
DER	Distributed Energy Resource
ELCC	Effective Load Carrying Capacity
EV	Electric Vehicle
E3	Energy and Environmental Economics
GDP	Gross Domestic Product
GT	Gas Turbine
GWh	Gigawatt hour
GHG	Greenhouse Gas
HVDC	High Voltage Direct Current
IRP	Integrated Resource Plan
kW	Kilowatt
LCOC	Levelized Cost of Capacity
LCOE	Levelized Cost of Energy
LDV	Light Duty Vehicle
LT	Long-Term PLEXOS module for capacity expansion
LOLE	Loss of Load Expectation
MLAP	Mactaquac Life Achievement Project
MHDV	Medium Heavy-Duty Vehicle
MT	Medium-Term PLEXOS module for day-ahead production cost optimization
MW	Megawatt
MWh	Megawatt hour
MMBtu	Million British Thermal Units
NERC	North American Electricity Reliability Council
NPCC	Northeast Power Coordinating Council
OBPS	Output Based Pricing System
PRR	Partial Revenue Requirement
PPA	Power Purchase Agreement
ROE	Return on Equity
ST	Short-Term PLEXOS module for production cost optimization
SMR	Small Modular Reactor
WACC	Weighted Average Cost of Capital

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1 Executive Summary

1.1 Setting the Stage

NB Power is on a path to transformation. The energy world is changing at a faster pace than ever before. As the world is changing, NB Power is embracing this change to transform our business to focus on customer experience, energy security and a sustainable clean energy transition.

The economy is moving toward net-zero to protect the environment and tackle climate change. The 2023 Integrated Resource Plan (the IRP) outlines our pathways to net-zero and will more boldly show how NB Power is embracing clean energy.

Shifts of this nature require discipline and planning. While the shift to clean energy will increase cost pressure for customers, it also comes with opportunities to mitigate those costs. A robust plan is necessary to identify these opportunities and avoid surprises while working to phase-out coal by 2030 and become a net-zero electricity utility by 2035. The decarbonization of the electricity system by 2035 is a critical step toward the decarbonization of the New Brunswick economy by 2050.

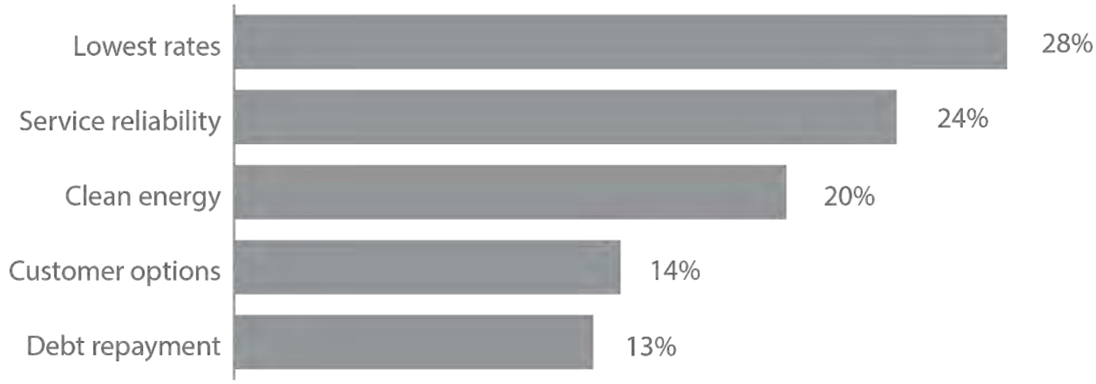
NB Power has a vision of providing clean, cost-effective and reliable energy for future generations of New Brunswickers. Many important factors contribute to bringing that vision to life, while still offering the best customer experience, ensuring energy security and accelerating a sustainable clean transition.

The Integrated Resource Plan paints a robust, long-term picture for New Brunswick's energy supply and demand, with a continued focus on reducing NB Power's greenhouse gas emissions and achieving a net-zero electricity system by 2035. It also looks out at the next 20 years with a view to how NB Power can make the best short- and long- term energy decisions for customers. It balances supply-side (generating stations) with demand side (customer-driven programs) options while meeting federal and provincial regulations, recognizing the corporation's mandate and the provincial *Electricity Act*. All of this is done under the umbrella of NB Power's environmental leadership and responsibilities in an evolving energy landscape.

It is important that New Brunswickers have a say in the planning process for the 2023 Integrated Resource Plan. Over the past year, NB Power has engaged Indigenous peoples, customers and key stakeholders through a broad, multi-platform public engagement campaign to better understand what mattered most when considering the Province's energy future.

The results showed us that New Brunswickers prioritized low rates and service reliability above clean energy, customer options and debt management. Overall, the prioritization was relatively evenly distributed, reinforcing NB Power's balanced approach to a sustainable transition to a net-zero electricity system. Indigenous communities expressed a desire to play a larger role by owning or partnering on future projects to the mutual benefit of Indigenous communities and NB Power customers, something the utility is equally interested in expanding.

Figure 1.1: Public Engagement Findings – What Should NB Power Prioritize?



Every three years, as required by legislation, the Integrated Resource Plan is refreshed to reflect the changing energy landscape and customer expectations. Through this process, NB Power will continually monitor changes in the landscape including, the Mactaquac Life Achievement Project, development of small modular reactors, the Atlantic Loop as well as broader trends around the electrification of industry and transportation, behind-the-meter generation and renewable energy costs. Once updated, as per the *Electricity Act*, NB Power submits the Integrated Resource Plan to the Government of New Brunswick for approval and then submits it to the New Brunswick Energy and Utilities Board (NBEUB) following that approval.

The IRP follows three core principles

- least-cost planning
- economic and environmental sustainability
- risk management

It is important to balance these principles with NB Power's mandate to keep rates cost-effective and stable for New Brunswickers while reaching a debt-to-equity ratio of 80/20 by fiscal year 2026/27. The *Electricity Act* requires the New Brunswick Energy and Utilities Board to consider the most recent Integrated Resource Plan when making decisions on rate setting and major capital spending. While this plan supports that process, it does not include information on electricity rates or detailed financial statements. This information is included in NB Power's 3-Year Plan, which, per the *Electricity Act*, must align with the most recent IRP.

1.2 Greenhouse Gas (GHG) Considerations

The reduction of greenhouse gas (GHG) emissions is critical to meeting the climate change goals. In 2021, Canada set a target for GHG emission reduction of 40 to 45 per cent below 2005 levels by 2030, as legislated in the Canada Net-Zero Emissions Accountability Act[1]. This legislation also set a target to achieve economy-wide net-zero emissions by 2050. New Brunswick has set the goal of reducing provincial greenhouse gas emissions to 10.7 megatonnes (Mt) by 2030[2], a 46 per cent reduction from 2005 levels.

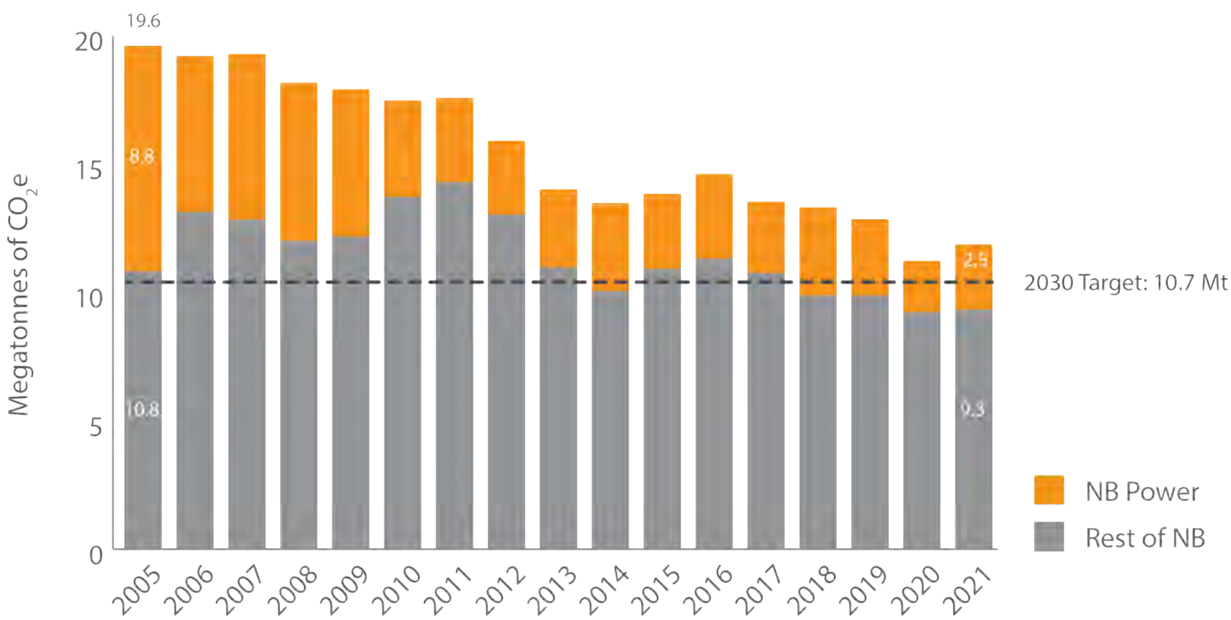
[1] *Canadian Net-Zero Emissions Accountability Act (S.C. 2021, c.22). Retrieved from the Justice of Laws website https://laws-lois.justice.gc.ca/eng/acts/C-19.3/fulltext.html*

2 *Government of New Brunswick. Climate Change Act, (SNB 2018, c 11). Retrieved from the CanLII website https://canlii.ca/t/54vxz*

In 2022 New Brunswick released its latest Climate Change Action Plan which further committed the province to net-zero GHG emissions by 2050[3]. The Climate Change Action Plan calls for New Brunswick to develop a strategy to achieve a net-zero electricity system by 2035, inclusive of two first-of-a-kind small modular reactors (SMRs). The IRP sets the foundation for achieving this goal.

In 2021 (the most recent year information is available at the time of writing) provincial emissions had declined significantly to 11.8 Mt[4,5], a 40 per cent reduction from 2005 levels. During this same period, NB Power's contribution to provincial emissions decreased from 8.8 Mt in 2005 to 2.5 Mt in 2021, an over 70 per cent reduction.

Figure 1.2: New Brunswick's Historical Greenhouse Gas Emissions 2005-2021[6,7]



[3] Our Pathway Towards Decarbonization and Climate Resilience, New Brunswick's Climate Change Action Plan 2022-2027. Retrieved from the Government of New Brunswick website https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/climate/climate-change-action-plan.pdf

[4] NB Power emission data based on internal data for NB Power owned facilities.

[5] Balance of total 2021 data sourced from: "National Inventory Report 1990-2021: Greenhouse Gas Sources and Sinks in Canada. Part 3," Government of Canada, last modified July 22, 2022 https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/sources-sinks-executive-summary-2022.html

[6] 2022 data not available at time of writing. 2005-2021 data sourced from: "National Inventory Report 1990-2021: Greenhouse Gas Sources and Sinks in Canada. Part 3," Government of Canada, last modified April 14,, 2023 https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/sources-sinks-executive-summary-2023.html.

[7] NB Power emission data based on internal data for NB Power owned facilities.

NB Power takes pride in reducing emissions by over 70 percent from 2005 levels, which did not occur by chance, but were actively initiated and pursued. Key actions taken by NB Power include

- adding 352 MW of wind generation since 2007, including 38 MW of new Indigenous business-based wind energy in 2019/20
- closing two fossil fuelled generating stations in 2010 and 2012
- refurbishing the world's first CANDU-6 nuclear reactor in 2012
- increasing renewable energy to over 40 per cent (42 per cent in 2021/22 and 52 per cent in 2022/23)
- adding 20 MW of embedded generation since 2010
- increasing energy efficiency through demand side management programs (87 MW reduction to peak demand since 2013)

While efforts to reduce emissions to date are encouraging, NB Power recognizes the threats of climate change and that there is still much more work to do to limit the effects of climate change. NB Power is a leader in emissions reductions and is committed to continuing to build on its success. As outlined in the company's strategic plan, NB Power will continue to decarbonize the electricity system achieving net-zero by 2035 in order to enable the broader decarbonization of the provincial economy by 2050. NB Power and the Province of New Brunswick are planning future actions to help enable carbon reduction across the province, including

- issuing a Request for Expressions of Interest for new renewable generation sources including 200 MW wind, 15 MW solar, 5 MW tidal and 50 MW 4-hour duration battery storage in February of 2023
- continuing to expand energy efficiency program savings to 0.75 per cent of sales by 2028/29
- enabling the decarbonization of other sectors through electrification of the transportation, heating and industrial sectors
- pursuing major projects that would enable the transition of New Brunswick's electricity sector toward net-zero including, but not limited to
    - Mactaquac Life Achievement Project
    - small modular reactors (SMRs)
    - exploring options to phase-out coal and replace with renewable energy
    - evaluating the Atlantic Loop transmission project

Three key policies govern GHG emission reduction in New Brunswick: the phase-out of coal, the output-based pricing system (OBPS) and the Clean Electricity Regulation (CER). Refer to Section 4.3 for more details on GHG regulations.

In 2018, the federal government announced the phase-out of coal-fired generation by 2030[8]. The regulation would see Belledune Generating Station cease to burn coal in 2030, 10 years earlier than its planned retirement date. NB Power continues to explore options to continue operation of Belledune Generating Station past 2030 using alternative fuels. Some of these fuel options include traditional biomass, torrefied biomass, liquified natural gas, renewable natural gas and conventional natural gas.

A significant input into the IRP is the New Brunswick Output-based Pricing System (OBPS) for large emitters[9]. The OBPS is a framework for pricing carbon emissions. It is subject to increasing stringency over time and a rising price on carbon, reaching $170 per tonne in 2030, resulting in larger emission penalties and reducing emissions from the electricity sector over time.

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[8] *Government of Canada. Canada's coal power phase-out reaches another milestone, December 12, 2018, https://www.canada.ca/en/environment-climate-change/news/2018/12/canadas-coal-power-phase-out-reaches-another-milestone.html.*

[9] *Government of New Brunswick. New Brunswick Regulation 2021-43 under the Climate Change Act (O.C. 2021-152). Retrieved from the CanLII website https://www.canlii.org/en/nb/laws/regu/nb-reg-2021-43/latest/nb-reg-2021-43.html*

The federal government is developing the Clean Electricity Regulation (CER), which would significantly restrict the operation of unabated emitting electricity generating facilities. The key principles under the CER are

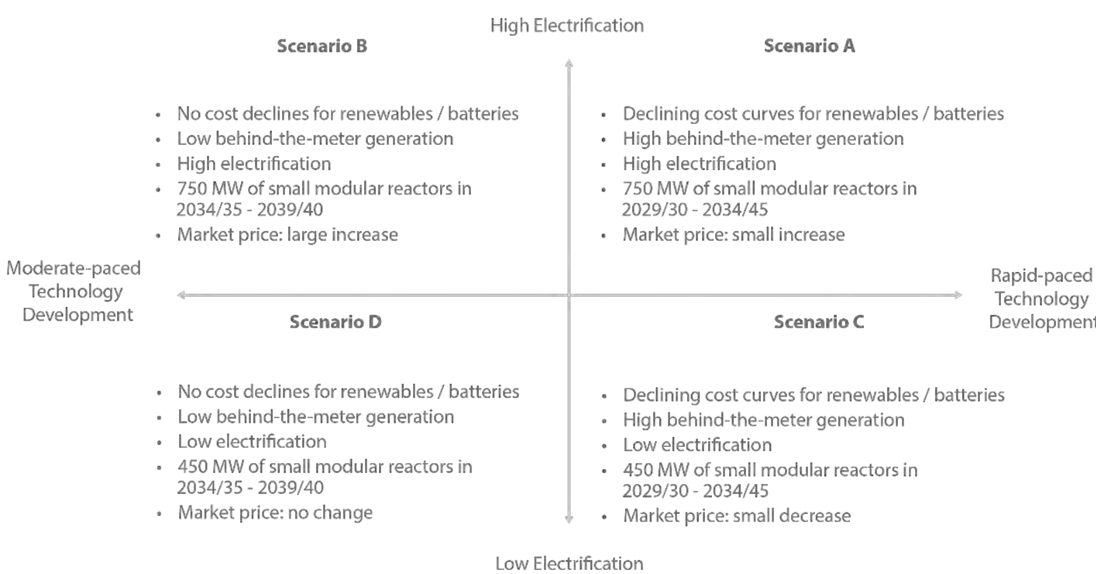
- base-loaded emitting plants would need to be equipped with carbon capture and storage capability or be co-fired with non-emitting fuels to limit their emission
- all emissions would be subject to paying the carbon price (eliminating the intensity standard approach used in the OBPS)
- the regulation includes a provision for allowing limited operation of emitting generators in order to integrate renewables and maintain reliability

Allowing limited operation of emitting generators in order to integrate renewables and maintain reliability is crucial to the sustainable transition to net zero and allows for continued, albeit limited, operation of Bayside, Coleson Cove, Millbank and Ste.-Rose generating stations after 2035. This is critical to maintaining reliability and security of supply while managing costs for our customers through the transition to a net-zero electricity system in New Brunswick.

1.3 Pathways to Net Zero

There is much uncertainty in navigating the pathways to net-zero by 2035. To handle this uncertainty, NB Power has taken a scenario-based approach to develop pathways to net-zero under a wide variety of conditions. The pace of electrification and technology development are difficult to predict and were chosen as key uncertainties for which NB Power must prepare. A four-quadrant scenario matrix was developed from these themes, to create a range of assumptions as to where our most likely future resides.

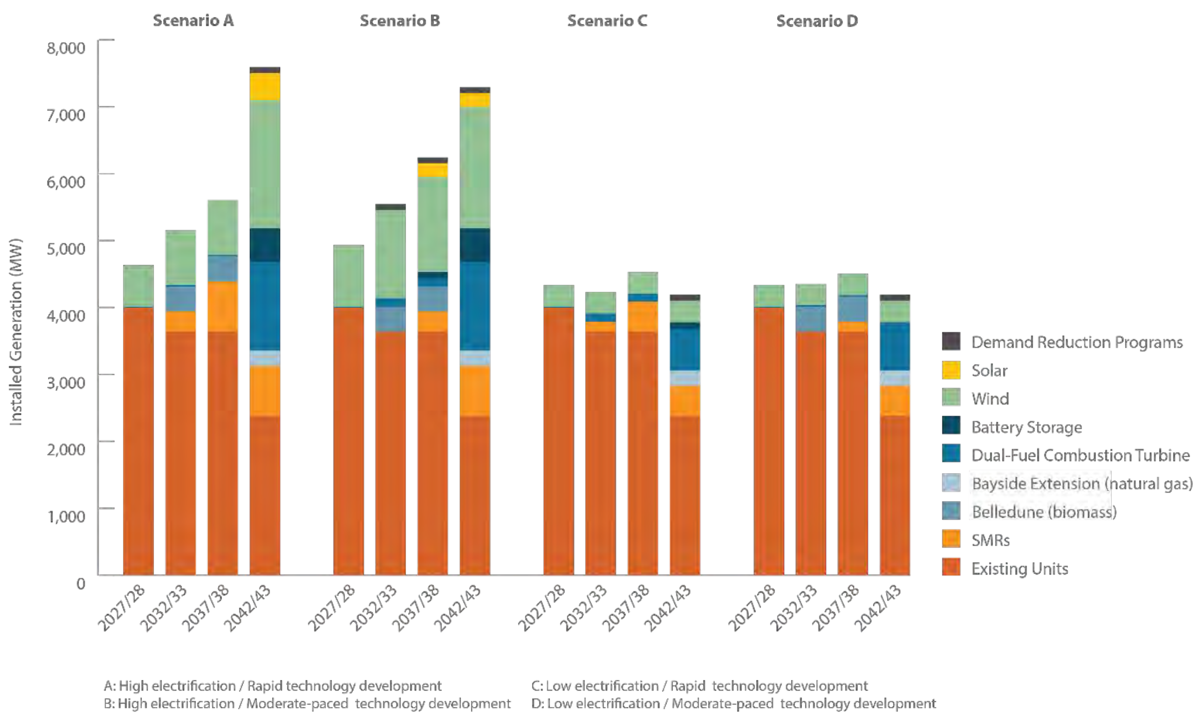
Figure 1.3: Scenario Summary



All scenarios lead to net zero but result in a range of new resources required to reliably serve electricity customers in New Brunswick. Generally, three things are needed: capacity to maintain reliability and energy security; carbon-free energy to eliminate production from emitting generators; and flexibility in units to provide operating reserves and integrate increasing variable renewables.

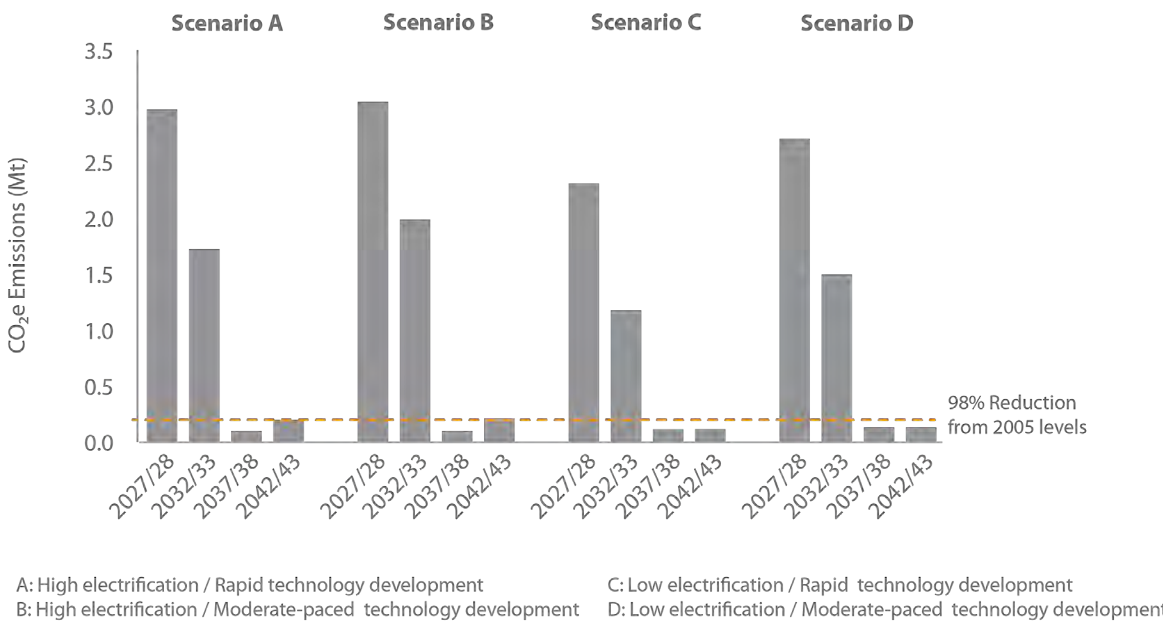
Some sources of capacity continue to use fossil fuels, but with limited operation profiles due to the restrictions included in the CER. Energy sources are mostly variable renewables such as wind and solar. Some projects, such as SMRs, the Belledune biomass conversion, Mactaquac Life Achievement Project and energy efficiency programs, are capable of providing both energy and capacity. Battery storage and Mactaquac are both well suited to providing flexibility to the system.

Figure 1.4: Installed (Nameplate) Generation by Scenario



Emissions after 2035 achieve a 98 per cent reduction from 2005 levels. Some small amounts remain in order to maintain reliability and energy security to sustainably transition to net-zero. After 2035, less than 175,000 tonnes of emissions remain on the grid. The remaining volume is equivalent to removing oil heat from 1,000 homes, taking 3,500 gasoline-fuelled vehicles off the road or planting 350,000 trees each year[10].

Figure 1.5: CO_2e Emissions by Scenario



Achieving net-zero will require new carbon-free generation projects such as Mactaquac Life Achievement Project, SMRs, Belledune biomass, new wind, new solar and new battery storage projects.

1.4 Key takeaways

The IRP has a number of key takeaways.

- Public Engagement findings indicate
    - the top two priorities for customers and stakeholders are limiting price increases and focusing on reliability and energy security
    - environmental concerns and carbon emission reductions are very important to Indigenous people and all New Brunswickers
    - the desire of Indigenous communities to be involved in owning and partnering on future projects presents NB Power with an opportunity to build on reconciliation efforts and continue positive relationship developments with Indigenous communities in New Brunswick. Partnerships on future generation projects can have positive financial benefits for all parties.

- NB Power's goals of achieving and maintaining a capital structure of 20 per cent equity will drive the need to invest in partnerships for clean electricity.

- Provincial GHG emissions are on a downward trend due to the combination of carbon pricing, coal-phase-out and the Clean Electricity Regulation (CER).

[10] *Lifetime GHG emission savings assumed at 175 tonnes per oil-heated home, 50 tonnes per gasoline vehicle and 0.5 tonnes per tree.*

- The CER's impact on emissions comes at a cost. In the base scenarios, costs increase an average of 14 per cent from 2032/33 to 2037/38 (before transmission and distribution investments).

- Emitting thermal units continue to operate at low capacity factors after 2035. Provisions in the CER for the continued operation of these facilities is critical to maintaining reliability and managing the cost of the clean transition.

- As the penetration on renewables such as wind and solar grows, the ability to dispatch these resources becomes increasingly important to maintaining reliability.

Table 1.1: Summary of Common Actions

Year	Installed Generation	Technology
2026/27	300 MW	Wind
2027/28 to 2032/33	668 MW	Mactaquac Life Achievement Project
2034/35	150 MW	SMRs
2038/39	230 MW	Bayside Gas Turbine Extension
2039/40	450 MW	SMRs
2040/41	600 MW	Dual Fuel Combustion Turbines
2040/41	90 MW	Demand Response

- Wind generation provides value across all base scenarios with at least 300 MW of installed capacity added by 2027/28.

- The Bayside Gas Turbine (GT) Extension is an excellent alternative to retirement. It is selected across all plans and is the lowest cost source of capacity of all options examined.

- The Mactaquac Life Achievement Project has tremendous value in the NB electricity system by providing clean electricity, capacity and low-cost, carbon-free generation that can provide ancillary services. Mactaquac's flexibility also enables the low-cost integration of renewables, which becomes increasingly important in the future.
    - A sensitivity analysis that retired Mactaquac in 2030 identified much higher generation and purchased power totalling $2.8 – 3.8 billion ($2022 net present value (NPV)) over the life of the project[11].

- SMRs are a critical part of the future of electricity in New Brunswick. They provide a unique opportunity for New Brunswick to offer stable and predictable carbon-free generation.
    - a sensitivity analysis that removed SMRs identified extreme volumes of wind and solar builds (over 4,000 MW) for some scenarios, which are orders of magnitude higher than any wind integration study completed to-date. More investigation is recommended.

- The Belledune biomass conversion is selected in many scenarios. It is sensitive to the amount of electrification in the province as well as the presence of other major projects. In all 'High Electrification' scenarios as well as all scenarios where the Mactaquac Life Achievement Project or SMRs are not present, the project provides value to customers. This supports further investigation into the conversion viability.

[11] *Excluding the capital and other operation costs for the Mactaquac Life Achievement Project.*

- A sensitivity that included increased transmission import capacity via the Atlantic Loop identified that it can help enable decarbonization, but its economic value is challenged
    - the combination of infrastructure cost plus increased generation and purchased power costs would raise costs to New Brunswick electricity customers by $270-$310 million per year in the 2040s, an approximate seven to nine per cent increase in costs in those years over the scenarios without the Atlantic Loop
    - a lower-cost solution is to build carbon-free resources in New Brunswick

- The build-out of new wind and other renewables requires more system integration, operational and transmission studies. In some scenarios, installed capacities approach 10 times the current installed capacity in New Brunswick, highlighting the issues of system reliability and energy security that will require further study should changes in the landscape suggest we are moving in the direction of one scenario over another. The addition of this much new wind and other renewables will require significant investment in transmission and distribution infrastructure the costs of which have not been quantified in the IRP as it is uncertain where these potential resources would ultimately choose to interconnect.

The IRP provides a view of numerous pathways toward a net-zero electricity system. The general take-away is that there is no silver bullet. Achieving net-zero will require new carbon-free generation projects such as MLAP, SMRs, Belledune biomass, new wind, new solar and new battery storage projects.

2 Introduction

2.1 NB Power Strategic Plan Overview

NB Power is on the cusp of a transformation being driven by our desire to meet customers' evolving expectations while placing us in a stronger financial position and continuing the path to cleaner, greener energy.

These days of uncertainty will require new ways of thinking and new ways of operating.

Global challenges such as inflation, political and social unrest, supply chain disruption and climate change impacts are having massive impacts on NB Power.

NB Power's strategic plan, *Energizing Our Future*, is designed to ensure the utility is making the right strategic decisions to meet the needs of New Brunswickers.

The current generation fleet and usage of electric-based space heating positions New Brunswick ahead of many others on the journey to decarbonization.

The strategic plan will mean exploring new, cleaner ways of delivering energy to customers and seeking new partnerships to improve service delivery and NB Power's financial position as well as ensuring we have a stronger, smarter grid. We will pursue two small modular nuclear reactors and find new revenue opportunities.

The strategic plan has six transformers

- Transition to a cost-effective, clean and secure energy supply
- Modernize the grid
- Electrify and grow load
- Deliver competitive customer value
- Create a thriving workforce
- Align, engage and optimize

These transformers will guide us as NB Power undertakes transformational change to ensure the transition to a cost-effective clean and secure supply of energy by modernizing the grid and driving electrification.

NB Power has also renewed its mission, vision and values for the utility. They combine our traditional values: our commitment to safety, quality customer service and the well-being of our teams with the need to transition to cleaner, greener energy.

The mission, vision and values were developed through a lengthy, collaborative process that involved focus groups with employees, managers and executives and serve as the foundation of the new strategic plan.

Our Vision

We enhance lives by providing clean, competitive and reliable energy solutions.

Our Mission

We are passionate and committed to offering the best customer experience, ensuring energy security and accelerating a sustainable clean energy transition.

Our Values

Safety at Heart	Care for Our Team	Care for Our Customers	Care for Our Future

2.2 Integrated Resource Planning Process

NB Power delivers New Brunswickers a mix of energy from many sources. It's a balance of cost, reliability and environmental impact. There's a lot of planning that goes into keeping that balance and this plan plays an important part in ensuring we can continue to do that going forward.

This IRP outlines long-term strategies to ensure NB Power's system stays reliable, financially stable, environmentally sound and efficient. It also identifies ways NB Power can continue to meet energy demand, while increasing renewables and decreasing its environmental footprint.

Gathering input from New Brunswickers is an essential part of the IRP process. NB Power sought the input of Indigenous communities, customers and key stakeholders, to gain a deeper understanding of what's important to them as they think about New Brunswick's electricity future. This feedback was used to align the priorities and direction of the IRP and set the scenario, sensitivity and other key assumptions.

Options to supply future electricity needs are selected based on

- system reliability
- environmental footprint
- overall cost effectiveness
- Indigenous community, customer and key stakeholder feedback

These options cover a wide range of generation sources and storage technologies. The cost of each supply option is strongly considered when weighing supply options. The plan needs to be realistic and ensure all selected supply-side options (including the environmentally preferred power generation choices) are affordable and reliable for New Brunswickers.

In addition to supply options, the integrated planning nature of this document means equal consideration is given to energy efficiency and demand management programs. These programs reduce New Brunswick's electrical consumption through customer energy savings and demand reduction.

A modern grid must be smarter, greener, cleaner, more resilient and efficient so New Brunswickers will have more choices and opportunities in the future for how they use energy. It will enable new technologies and services, while keeping the grid stable, efficient and reliable for customers.

To create this plan, NB Power follows an industry standard, well-defined process. This process can be broken down into a series of steps

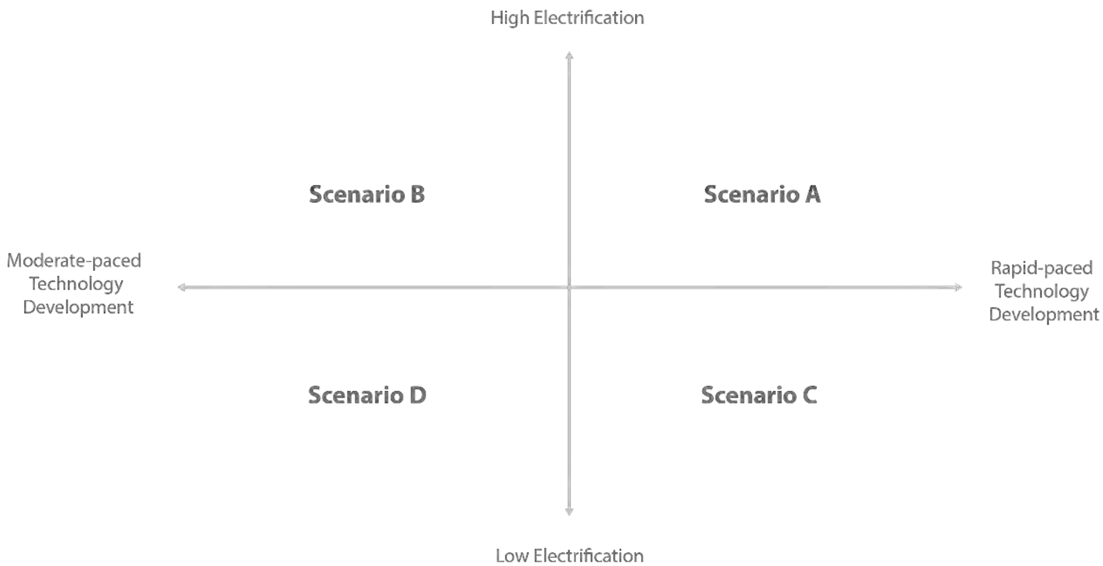
1. provide Indigenous communities, customers and stakeholders opportunities to improve their energy literacy and provide input about their evolving electricity needs
2. develop key assumptions including
    a. future policies or regulations
    b. economic assumptions (e.g. fuel pricing, financing rates)
    c. forecasted in-province electricity requirements
    d. end-of-life dates for existing resources
    e. cost estimates of supply and demand options
3. identify technical constraints including
    a. reliability metrics (e.g. effective load carrying capability)
    b. planning reserve margin requirements
    c. ancillary support requirements
    d. operational constraints
4. determine least-cost resource portfolio while meeting all policy and technical constraints

2.3 IRP Scenario Analysis

The electricity industry is in the midst of unprecedented change and uncertainty. Many different things are creating significant uncertainty over the future direction of the electricity industry. Technology is changing at a rapid pace with existing technologies becoming more efficient and new technologies being developed. Government policy and utility regulations are changing rapidly to deal with climate change. Pandemic responses and geopolitical events have caused upheaval to fuel prices and supply chains which in turn affect inflation and economic growth. All of these influences interact in different ways and create significant uncertainty affecting how NB Power plans for the long-term.

Scenario planning is an effective way to manage the uncertainty created by global events, policy changes, technological improvements and changing consumer usages of electricity, all of which are out of utility control. NB Power looked at all the different drivers and chose the pace of decarbonization, as represented by the pace and volume of electrification of loads and the pace of technological development. Using these two drivers NB Power can create four different scenarios establishing a range of possible outcomes that can be tested. Within the boundary provided by these scenarios the most likely future can be found and strategies that work in all scenarios can be prioritized.

Figure 2.1: Scenario Matrix



Pace of decarbonization, as represented by electrical load, was chosen as one axis due to the significant uncertainty around the pace of transportation and industrial electrification. In addition to this uncertainty is the potential development and subsequent impact to the electricity grid of energy intensive industrial processes such as hydrogen production or low-carbon intensity steel production.

- In Scenarios A and B, a fast-paced transportation electrification will be considered along with disruptive growth of electricity intensive industries.
- In Scenarios C and D, slower growth will be considered.

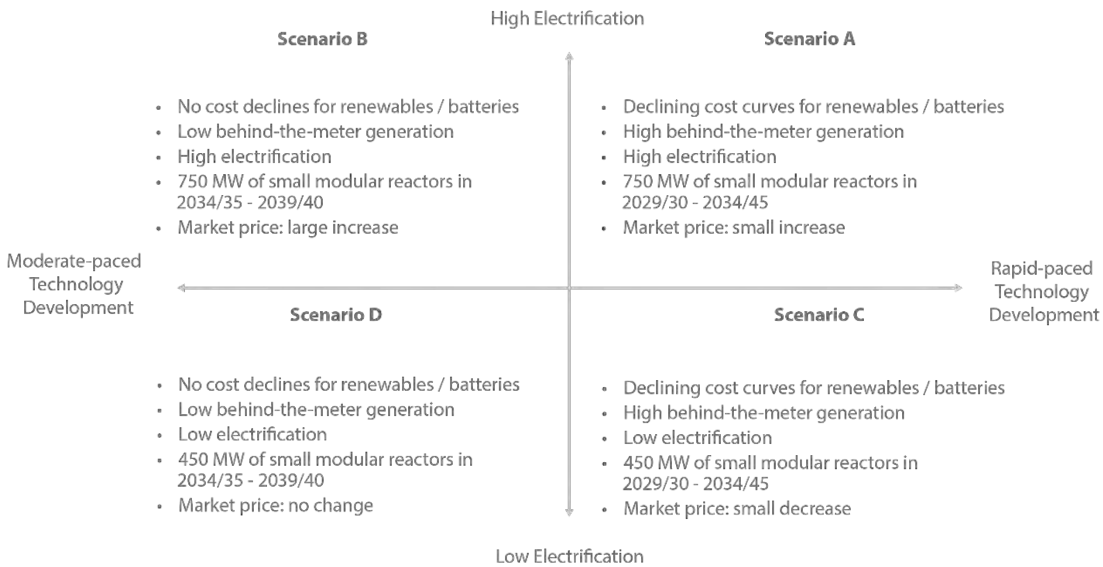
Technology development was chosen as the second axis of uncertainty.

- Scenarios A and C, will explore the impact to the system of continued gains in efficiency and cost declines of renewable energy technologies.
- Scenarios B and D, will consider these technologies as having no further declines in costs.

Using these two axes to inform the scenario analysis provides four different scenarios that will provide a boundary where most likely futures land. Sensitivity analysis can then be performed on all four scenarios to analyze the effects of specific projects such as the Mactaquac Life Achievement Project, small modular reactors and the Atlantic Loop. The use of scenarios will allow the IRP to be resilient against uncertainty and allow the document to provide better policy support.

Figure 2.2 shows a summary of the four base case scenarios that will be examined.

Figure 2.2: Scenario Assumptions Matrix



Further detail around assumptions and structure of the scenarios can be found in Section 11.2.

3 Engagement

3.1 Overview of Engagement Process

As NB Power began planning for this IRP, it was important to involve Mi'kmaq, Wolastoqiyik and Peskotomuhkati Indigenous communities, New Brunswickers and key stakeholders. This was accomplished through a multi-platform engagement strategy.

The design of the engagement process was a collaborative effort between NB Power and its engagement consultant, National Public Relations.
In August and September 2022, NB Power hosted in-person and online engagement sessions to capture input from New Brunswickers from across the province to learn what matters most to them when considering New Brunswick's energy future.

The objectives of the engagement were to

- gain a deeper understanding of what is most important to customers as they consider New Brunswick's energy future and the role they, as New Brunswickers, are willing to play in it
- provide ample and appropriate information, in an easy-to-understand format, about New Brunswick's energy landscape, the scope of the IRP process and what can be influenced
- host forums for New Brunswickers to contribute based on their own perspective, experience, ideas and what is most important to them
- be transparent in sharing results in the *What Was Said Report*[12]

[12] *"What Was Said Report", National Public Relations, 2023, https://www.nbpower.com/en/about-us/our-energy/integrated-resource-plan*

3.1.1 Scope of Engagement

The engagement campaign consisted of an online survey and in-person customer engagement sessions hosted across New Brunswick.

NB Power promoted these engagement opportunities to New Brunswickers in both official languages through the following tactics

- social media platforms Facebook, Twitter and LinkedIn were leveraged to connect with key audiences
- direct email invitations were sent to over 2,000 customers who previously consented to receiving ongoing communications from NB Power
- paid media and digital ads on Instagram, LinkedIn and Facebook
- Indigenous communities were contacted and invitations were extended to participate in the survey and for face-to-face meetings
- community events and meetings were attended

Six thousand, one hundred and sixty-three (6,163) New Brunswickers participated online, while 145 were engaged at in-person opportunities, for a total of 6,308 engagements. The level of engagement declined by six percent from 2019 levels, primarily due to reduced in-person engagements at community events. Illness and poorly timed weather cancelled several open-air engagements reducing overall contact with customers.

Table 3.1: Summary of Public Engagement

Engagement Format	Number of Engagements
Community Event Face-to-Face Conversations	125
One-On-One Stakeholder Meetings	20
Online Survey	6,163
Total	6,308

3.2 In-person Engagement Approach

In-person customer engagement sessions were held in a variety of formats across the province.

3.2.1 Indigenous Community Engagement

NB Power respects the significance, distinct interests and culture of New Brunswick's Indigenous communities and continues to work hard to build and strengthen positive relations. NB Power engages with Indigenous communities continuously on many IRP-related issues such as business opportunities, partnerships and service delivery.

NB Power engaged with Indigenous communities in a variety of forms

- Indigenous Chiefs were invited to submit comments on the future direction and priority focus of NB Power
- individual community members were able to engage directly through the on-line survey

NB Power will continue to engage with Indigenous communities after the IRP has been published to ensure we continue to develop and sustain these important relationships. NB Power is in the process of meeting with focus groups made up of elders, leaders and community members to gather input on NB Power and to provide energy literacy to our Indigenous partners. The feedback received from Indigenous communities indicated a desire for reconciliation, input on land usage and returns, and increased dialogue. Indigenous communities also indicated a strong desire to be part of future development opportunities as owners or partners in the development of renewable energy projects and SMRs.

3.2.2 Face-to-Face Conversations with New Brunswickers

NB Power wanted to meet with people in places where they naturally gather and socialize to capture the attention of New Brunswickers and gather input for the 2023 IRP. NB Power met with customers at numerous meetings and events in August and September to have these discussions. These took place at the gathering of New Brunswick cities, at community liaison committees in Milltown, Fredericton and Bathurst, and at the Harvest Music Festival.

3.2.3 One-on-One Stakeholder Meetings

Where the online engagement tool primarily targeted residential and small business customers, face-to-face meetings were held with other customer classes and interested stakeholders from across the province to ensure representative balance and avoidance of gaps in the process. NB Power met face-to-face with these customers to ensure their input was properly reflected in the development of the IRP.

3.3 Online Public Engagement Survey

The online engagement experience was designed with a general audience in mind. Content was concise and used plain language.
It explored the following topics

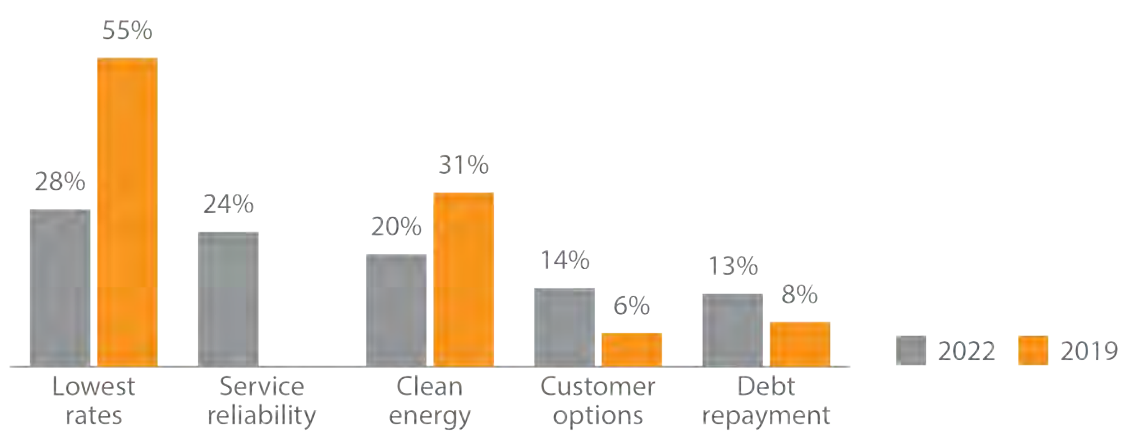
- affordability
- reliability
- clean energy
- customer options

Participants could also include their own comments at the end of the short survey.

3.3.1 Online Public Engagement Findings

According to the survey results, affordability is the most important priority for New Brunswickers. However, service reliability is a close second with clean energy taking third place. Service reliability was added to the survey this year to ensure energy security concerns can be tracked as we advance to net-zero. It is important to note that customer options and debt repayment have increased in importance to New Brunswickers even with the addition of a fifth category. The lack of a clear priority suggests New Brunswickers want NB Power to focus on cost-effective rates, service reliability and clean energy with due attention to customer options and debt repayment.

Figure 3.1: Summary of Public Engagement Findings



Based on survey responses, most New Brunswickers support the transition to cleaner energy but believe it needs to be balanced against rates and reliability. The majority of respondents said they're not willing to pay more for clean energy. New Brunswickers are looking to NB Power to support energy efficiency and provide products and services to help manage their electricity usage and lower their bills. Interest in electric vehicles is up significantly from the previous survey but is still a minority of customers.

The statements New Brunswickers agreed the most with were

- New Brunswick's transition to a clean energy future needs to minimize impacts on rates and the economy (84 per cent)
- I want NB Power to be a leader in energy efficiency (80 per cent)
- I want NB power to invest in providing more customer options (programs, products and services) to better manage my electricity needs (80 per cent)

The statements New Brunswickers agreed with the least were

- I am personally willing to pay more for clean energy (26 per cent)
- I am interested in purchasing an electric vehicle (41 per cent)
- I am interested in producing my own electricity (50 per cent)

A full report on findings and input can be found in the *What Was Said Report*[13].

4 Policy Considerations

As a Crown corporation, NB Power adheres to various policies and regulations set out by the provincial government. This section provides background on the *Electricity Act*, Regulations and NB Power's Mandate Letter.

The theme of the 2023 IRP is exploring NB Power's pathways to net-zero by 2035. This will align with the province's *Climate Change Action Plan 2022-2027*[14]. Action 7 is provided below

7. *Develop a Clean Electricity Strategy by 2025 for achieving net-zero electricity emissions by 2035, based on guiding principles that support clean, reliable, efficient, and affordable electricity. The Strategy is expected to:*
    a. *Identify the role of renewable energy, including distributed energy, that may support the electricity grid, lower peak demand, and provide capacity support. This may also include the role of storage, renewable and clean fuels such as clean hydrogen, geothermal, renewable natural gas (RNG) and biomass, in New Brunswick's energy systems in all sectors;*
    b. *Include the development of two first-of-their-kind small modular reactor technologies;*
    c. *Strengthen investments and broaden the scope of energy efficiency and demand-side management initiatives, including improving access to programs for moderate-income families;*
    d. *Set a clear path to transition off coal-fired electricity; and*
    e. *Explore regional opportunities to share clean electricity resources to meet the increasing demand for electrification.*

[13] *"What Was Said Report", National Public Relations, 2023, https://www.nbpower.com/en/about-us/our-energy/integrated-resource-plan*

[14] *Government of New Brunswick. Our pathway towards decarbonization and climate resilience: New Brunswick's Climate Change Action Plan 2022-2027. https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/climate/climate-change-action-plan.pdf*

4.1 The *Electricity Act*

The New Brunswick *Electricity Act* is the legislation that sets out the framework and rules of law for how the electricity sector is managed in the province.

NB Power's Integrated Resource Plan is impacted by a number of provisions and requirements in the *Electricity Act*. Section 100 of the *Electricity Act* establishes the requirement for an Integrated Resource Plan. It lists several elements that must be included in the Integrated Resource Plan, as well as setting out required timelines for submission to and approval by the Executive Council of the Government of New Brunswick. Subsection 100(2) requires the Integrated Resource Plan be developed by the Corporation in accordance with the principles of least-cost service, economic and environmental sustainability and risk management.

The *Electricity Act* also includes government policy directives that guide utility planning, notably in Section 68

- NB Power is to achieve a capital structure of at least 20 per cent equity (s. 68(a))
- ensures New Brunswickers have safe, secure and equitable access to electricity at least cost of service (s. 68(b))
- taking into account the above policy requirements, and to the extent practicable, rates shall be maintained as low as possible and stable from year to year (s. 68(c))

The *Electricity Act* also makes NB Power responsible for promoting, developing and delivering energy efficiency, energy conservation and demand side management programs in New Brunswick.
In 2022, the Government of New Brunswick prescribed in regulation[15] minimum energy efficiency targets for electricity as summarized in Table 4.1.

Table 4.1: Energy Efficiency Targets (per cent of in-province electricity sales)

Year	Target Reduction
2023/24	0.50 %
2024/25	0.55 %
2025/26	0.60 %
2026/27	0.65 %
2027/28	0.70 %
2028/29 and thereafter	0.75 %

4.2 Electricity from Renewable Resources Regulation – *Electricity Act*

In 2015, the Government of New Brunswick committed to develop more renewable energy in New Brunswick. The *Electricity from Renewable Resources Regulation – 2015-60*[16] guides the development of renewable electricity resources in New Brunswick. The regulation requires NB Power to supply 40 per cent of its in-province electricity sales with renewable energy.

[15] *Government of New Brunswick, New Brunswick Regulation 2022-74 under the Electricity Act (O.C. 2022-287). Retrieved from the CanLII website, https://www.canlii.org/en/nb/laws/regu/nb-reg-2022-74/latest/nb-reg-2022-74.html*

[16] *Government of New Brunswick, New Brunswick Regulation 2015-60 under the Electricity Act (O.C. 2015-263), Retrieved from the Government of New Brunswick web site, https://www2.gnb.ca/content/dam/gnb/Departments/ag-pg/PDF/RegulationsReglements/2015/2015-60.pdf.*

While the goal of the regulation is to reduce the use of fossil fuel generation and emissions, that objective can be met by either reducing energy use through energy efficiency or by acquiring renewable generation. In many cases, reducing energy use through energy efficiency programs is more cost-effective than building new renewable generation.

Energy efficiency also helps achieve New Brunswick's environmental goals. NB Power has significantly expanded its energy efficiency program offerings in recent years and will continue to do so. Reducing and shifting customer electricity consumption will reduce the need for future generation from fossil-fuelled plants and increase the share of New Brunswick's electricity needs provided by renewables. Innovative programs that lead to significant energy reduction will allow NB Power to maintain or exceed the 40 per cent renewable portfolio standard in the most cost-effective and efficient way while also reducing greenhouse gas emissions.

The *Electricity from Renewable Resource Regulation – 2015-60* also enables the Locally Owned Renewable Energy Projects that are Small Scale Program, focused on Indigenous business and the Large Industrial Renewable Energy Purchase Program. These programs contribute to the 40 per cent renewable energy target described above. NB Power added 38 MW of Indigenous-owned wind under the Locally Owned Renewable Energy that is Small Scale (LORESS) regulation in fiscal year 2019/20.

The key objectives of the *Electricity from Renewable Resource Regulation – Electricity Act* are[17]

- low and stable energy prices – integrate additional renewable energy to help shield ratepayers from the cost volatility of electricity generated from fossil fuels
- energy security – develop additional indigenous renewable energy to lessen NB Power's dependence on imported fossil fuels
- environmental responsibility – additional renewable energy will reduce NB Power's greenhouse gas and associated emissions by reducing fossil fuel electricity generation

4.3 Greenhouse Gas Regulations

In 2015, Canada along with 194 other countries signed the Paris Agreement and collectively committed to reduce global emissions[18]. In March 2016, the First Ministers released the Vancouver Declaration on Clean Growth and Climate Change[19], which included a nationwide targeted reduction of emissions to 30 per cent below 2005 levels by 2030. In 2021, Canada further increased this targeted reduction to 40 to 45 per cent below 2005 levels by 2030, as legislated in the Canada Net-Zero Emissions Accountability Act[20]. This legislation also set a target to achieve economy-wide net-zero by 2050. New Brunswick has set the goal of reducing provincial greenhouse gas emissions to 10.7 Mt by 2030[21]. In 2022 New Brunswick released its latest Climate Change Action Plan 2022-2027 which further committed the province to Net Zero GHG emissions by 2050[22].

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[17] Renewable Portfolio Standard, (2023, March 3). Natural Resources and Energy Development, Government of New Brunswick.

[18] The Paris Agreement, (2016, January 6). Government of Canada. https://www.canada.ca/en/environment-climate-change/services/climate-change/paris-agreement.html.

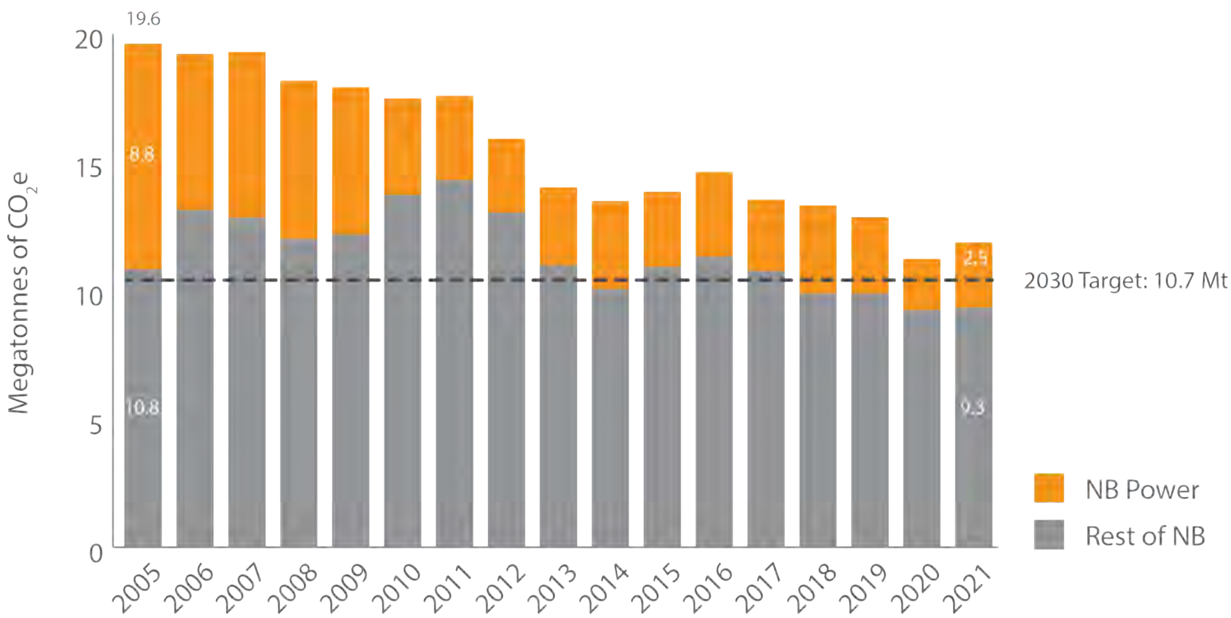
[19] Vancouver declaration on clean growth and climate change, (2016, March 3). Canadian Intergovernmental Conference Secretariat. https://scics.ca/en/product-produit/vancouver-declaration-on-clean-growth-and-climate-change/.

[20] Government of Canada. Canada Net-Zero Emissions Accountability Act (S.C. 2021, c. 22). https://laws-lois.justice.gc.ca/eng/acts/c-19.3/fulltext.html

[21] Government of New Brunswick. Climate Change Act (SNB 2018, c.11) Retrieved from CanLII website, https://canlii.ca/t/54vxz

[22] Government of New Brunswick. Our pathway towards decarbonization and climate resilience: New Brunswick's Climate Change Action Plan 2022-2027. https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/climate/climate-change-action-plan.pdf

Figure 4.1: New Brunswick's Historical Greenhouse Gas Emissions 2005-2021[23,24]



New Brunswick's 2005 emissions were 19.6 Mt. The 2030 emission target of 10.7 Mt represents a 45 per cent reduction, achieving the federal target of 40 to 45 per cent reduction.

New Brunswick has made considerable progress toward this goal, with provincial emissions of 11.8 Mt in 2021 (a 40 per cent reduction from 2005). NB Power has contributed to the province's success, reducing its emissions by 6.3 Mt since 2005 (a 72 per cent reduction, down to 2.5 Mt in 2021). Actions taken by NB Power, some as a result of changes to government regulations, that have contributed to this reduction include

- adding 352 MW of wind generation since 2007, including 38 MW of new community-based wind energy in 2019/20
- closing two fossil fuelled generating stations in 2010 and 2012
- refurbishing the world's first CANDU-6 nuclear reactor in 2012
- increasing renewable energy to over 40 per cent (51 per cent in 2020/21 and a 42 per cent in 2021/22)
- adding 20 MW of embedded generation since 2010
- increasing energy efficiency through demand side management programs (87 MW reduction to peak demand since 2013)

[23] *"National Inventory Report 1990-2021: Greenhouse Gas Sources and Sinks in Canada. Part 3," Government of Canada, last modified April 14, 2023 https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/sources-sinks-executive-summary-2023.html.*

[24] *NB Power emission data based on internal data for NB Power owned facilities.*

New Brunswick's largest provider of carbon-free energy is the Point Lepreau Nuclear Generating Station. The Station provides approximately 35 per cent of New Brunswick's electricity requirements and avoids approximately 4 Mt of greenhouse gas from being emitted into the environment annually. NB Power forecasts that at least 75 per cent of New Brunswick's electricity requirements will be met by carbon-free sources in each year until 2029. Afterward, the number increases significantly, approaching nearly 100 per cent in 2035 and beyond.

NB Power is also planning future actions to help enable carbon reduction across the province, including

- issuing a Request for Expressions of Interest for new renewable generation sources including 200 MW wind, 15 MW solar, 5 MW tidal and 50 MW 4-hour duration battery storage in February of 2023
- continuing to expand energy efficiency program savings to 0.75 per cent of sales by 2028/29
- enabling the decarbonization of other sectors through electrification of the transportation, heating and industrial sectors
- pursuing major projects that would enable the transition of New Brunswick's electricity sector toward net-zero including, but not limited to
  - Mactaquac Life Achievement Project
  - small modular reactors (SMRs)
  - Atlantic Loop
  - exploring options to convert Belledune Generating Station to sustainable biomass
- creating a clean energy rate to enable customers to desire to become net-zero before 2035[25]

In 2022, the province of New Brunswick issued a new Climate Change Action Plan[26] containing new incremental actions from the previous plan. Many of these actions influence the Integrated Resource Planning process, with some of the notable actions briefly summarized below.

Table 4.2: Summary of Key Actions from Climate Change Action Plan

Action	Description
#4 and #5	Supporting and promoting the adoption of electric and other non-emitting vehicles
#7	Develop a clean electricity strategy by 2025 for achieving net-zero electricity emissions by 2035
#8	Continue to expand energy efficiency offerings across all fuels
#9	Enable the production and use of renewable fuels (Hydrogen and renewable natural gas)
#10	Phase-out the use of heating oil
#11	Accelerate the adoption of National Building Codes and National Energy Codes with the objective of achieving net-zero energy ready construction by 2030

[25] *New Brunswick Energy and Utilities Board Matter 529*

[26] *Government of New Brunswick. Our pathway towards decarbonization and climate resilience: New Brunswick's Climate Change Action Plan 2022-2027. https://www2.gnb.ca/content/dam/gnb/Corporate/Promo/climate/climate-change-action-plan.pdf*

4.3.1 Coal Phase-Out

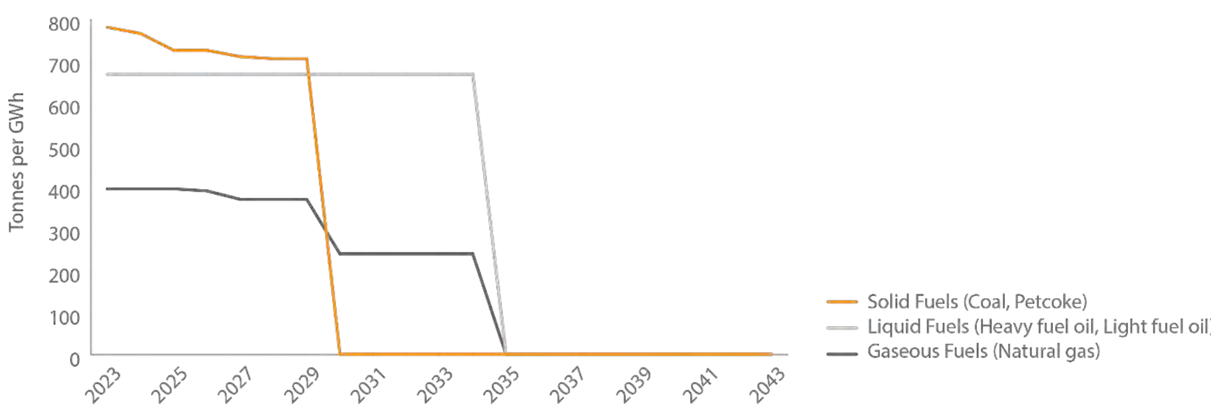
In 2018, the federal government announced the phase-out of coal-fired generation by 2030[27]. NB Power is scheduled to retire its only remaining coal-fired generating station located in Belledune in December 2040. The regulation would see Belledune Generating Station cease to burn coal in 2030, 10 years earlier than its planned retirement date. Belledune is a reliable source of low-cost energy and capacity that is only second to Point Lepreau in terms of providing energy for New Brunswickers. The phase-out of coal as a fuel source requires investment in either new infrastructure to allow for alternative fuels to be used at Belledune Generating Station or new generation with similar operating characteristics (i.e. dependable and predictable (dispatchable) generation with the ability to be base loaded). NB Power continues to explore options to continue operation of Belledune Generating Station past 2030 using different fuels. Some of these fuel options include traditional biomass, torrefied biomass, liquified natural gas, renewable natural gas and conventional natural gas.

4.3.2 Output-Based Pricing System Regulations

The IRP is based on New Brunswick's Output-based Pricing System (OBPS) for large emitters[28]. Large emitters are facilities or generating stations that emit more than 50 kt of greenhouse gas emissions per year. For NB Power, the regulated units would be the Belledune, Coleson Cove and Bayside generating stations.

Carbon pricing under the NB OBPS is $65 per tonne in 2023. It is regulated to increase by $15 per tonne each year until it reaches $170 per tonne in 2030[29]. Performance standards[30] vary by fuel type and tighten over time. NB Power will be subject to carbon taxes on emissions that exceed the performance standards set out in the NB OBPS[31].

Figure 4.2: New Brunswick OBPS Emission Intensity Standards



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[27] *Government of Canada. Canada's coal power phase-out reaches another milestone, December 12, 2018, https://www.canada.ca/en/environment-climate-change/news/2018/12/canadas-coal-power-phase-out-reaches-another-milestone.html.*

[28] *Government of New Brunswick. New Brunswick Regulation 2021-43 under the Climate Change Act (O.C. 2021-152). Retrieved from the CanLII website https://www.canlii.org/en/nb/laws/regu/nb-reg-2021-43/latest/nb-reg-2021-43.html.*

[29] *Greenhouse Gas Pollution Pricing Act (S.C. 2018, c.12, s. 186). Retrieved from the Justice of Laws website https://laws-lois.justice.gc.ca/eng/acts/g-11.55/FullText.html*

[30] *The Output-Based Pricing System uses a performance standard in the form of average emissions per unit of electric output. The utility would pay only on the emissions above this emission intensity standard. For example, if the performance standard were 370 tonnes per gigawatt-hour and a station's actual emission intensity were 470 tonnes per gigawatt-hour, the portion above 370 tonnes per gigawatt-hour, or 100 tonnes per gigawatt-hour, would be subject to the carbon price.*

[31] *Government of New Brunswick. New Brunswick Regulation 2022-83 under the Climate Change Act (O.C. 2022-316). Retrieved from the CanLII website https://www.canlii.org/en/nb/laws/regu/nb-reg-2021-43/latest/nb-reg-2021-43.html.*

After 2030, the performance standard for solid fuels goes to zero. For liquid and gaseous fuels, they are assumed to persist at 2030 levels until 2035, when they essentially become zero, as the clean electricity regulation becomes the dominant policy for pricing and controlling emissions.

For facilities that emit less than 50,000 tonnes per year (e.g. Millbank and Ste.-Rose), there is no performance standard and the carbon price is applied to all emissions.

4.3.3 Net-Zero 2035 (Clean Electricity Regulation)

The federal government is developing the Clean Electricity Regulation (CER), which would significantly restrict the operation of unabated emitting electricity generating facilities. In July 2022, Environment and Climate Change Canada released for comment some principles of the CER[32]. The key principles under this are

- emitting plants would need to be equipped with carbon capture and storage capability or be co-fired with non-emitting fuels to limit their emission
- all emissions would be subject to paying the carbon price (eliminating the intensity standard approach used in the OBPS)
- including a provision for allowing limited operation of emitting generators in order to integrate renewables and maintain reliability

To represent the impact of the CER, NB Power has included the following assumptions in years 2035 and beyond of the plan

- limit the operation of any unabated thermal plant to 5 per cent capacity factor or less
- replace the OBPS with a simplified price on all carbon of $170 per tonne

There remains considerable uncertainty on achieving a net-zero electricity system in New Brunswick. These assumptions serve to limit NB Power's emissions in all base scenarios to a 98 per cent reduction from 2005 levels. While this plan doesn't contemplate the full elimination of all emissions, it should serve to directionally guide decision makers in a sustainable direction. The small volume of outstanding emissions can be more appropriately addressed in subsequent IRPs as the future landscape and policies become more certain. For the purposes of this IRP, achieving the goals of the CER and resulting 98 per cent reduction in greenhouse gas emissions achieves the goal of a net-zero electricity system by 2035. After 2035, less than 175,000 tonnes of emissions remain on the grid. The remaining volume is equivalent to removing oil heat from 1,000 homes, taking 3,500 gasoline-fuelled vehicles off the road or planting 350,000 trees each year[33].

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[32] *Government of Canada, Proposed Frame for the Clean Electricity Regulations (2022). https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/proposed-frame-clean-electricity-regulations.html*

[33] *Lifetime GHG emission savings assumed at 175 tonnes per oil-heated home, 50 tonnes per gasoline vehicle and 0.5 tonnes per tree.*

4.4 NB Power's Mandate

The Mandate Letter from the Government of New Brunswick sets out the provincial government's intentions and expectations of NB Power. These items from the 2022/23 Mandate Letter[34] have a direct impact on the development of the IRP

- work with the Province to reduce greenhouse gas emissions and minimize the impact of the carbon price, considering impacts to electricity rates
- continue to deliver maximum benefit, highest-value energy efficiency programs for all sectors and for all fuels where funding is provided and with minimal market disruption
- make plans to achieve a capital structure of at least 20 per cent equity by 2026/27 through cost reductions and other appropriate mechanisms that will maintain low and stable rates for New Brunswickers
- continue to work with communities in the province, with a focus on Indigenous communities to provide opportunities to collaborate and partner in the electricity sector
- continue the ongoing support and advancement of the small modular reactors cluster with the various counterparties and support efforts to acquire federal funding for first-of-a-kind reactors at the Point Lepreau Nuclear Generating Station site
- continue to honour the mandate of the New Brunswick Energy Marketing Corporation to carry out the business of importing and exporting energy
- continue to support the Department of Environment and Climate Change in achieving its Climate Change Action Plan goals including creating additional opportunities for clean electricity development
    - this will include reopening the Embedded Generation Program and creating opportunities for additional community renewable energy projects
- continue to be the delivery agent for the Plug-In NB electric vehicle rebate program and energy efficiency programs and adapt the programs as funding and direction is provided

5 Economic Assumptions

In order to develop an integrated plan that keeps rates cost-effective and stable, NB Power performs various economic analyses to determine the financial impact of potential supply-side (such as a large generator) and demand-side (customer-driven actions) resources. The financial parameters used to complete the IRP analyses are

- consumer price index
- foreign exchange rate
- weighted average cost of capital

NB Power recognizes the significant inflationary pressures that have and continue to be experienced in Canada. In the near-term consumer price indices have hit upwards of 7 per cent. NB Power recognizes the near-term impact of this increase and reflects higher than normal inflation in the first few years of the IRP.

5.1 Consumer Price Index

The consumer price index (CPI) is used to adjust operations, maintenance and administration (OM&A) and regular capital expenditures in future years. CPI for 22/23 is forecast at 7.0 per cent dropping to 2.9 per cent in 2023/24 and gradually dropping to 2.0 per cent per year starting in 2026/27. This forecast is sourced from the Conference Board of Canada (CBOC) data published on October 31, 2022[35].

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[34] *2023-24 NB Power Mandate Letter*

[35] *Conference Board of Canada Quarterly Rates Data/Forecast Published October 2022.*

5.2 Foreign Exchange Rate

The long-term foreign exchange rate assumed in this IRP is $1.30 (USD/CAD)[36]. This rate is the six-year historical average exchange rate published by the CBOC and is used from fiscal 2029/30 to the end of the period. Forecasted data from the CBOC has been used for fiscal years 2022/23 to 2025/26, while a gradual linear adjustment to $1.30 (USD/CAD) has been assumed for fiscal years 2026/27 to 2028/29.

5.3 Weighted Average Cost of Capital

The weighted average cost of capital (WACC) is the calculation of a company's after-tax cost of capital, where each source of capital (debt and equity) is proportionally weighted. WACC is commonly used by companies to discount cash flows in the evaluation of investment decisions.

Table 5.1: Weighted Average Cost of Capital

Developer	Credit Rating	Debt Ratio	Equity Ratio	Long Term Bond Rate[37]	Spread (bps)[38]	Guarantee Fee	Interest Rate	Return on Equity	WACC
Investor-Owned	BBB	60%	40%	3.37%	210	0.00%	5.47%	11%	7.68%
NB Power	A+	80%	20%	3.37%	97	0.65%	4.99%	10%	5.99%

A reputable and creditworthy investor-owned power developer has a BBB credit rating[39]. The credit rating of government-sponsored enterprises, such as NB Power, is assumed to be rated same as the sponsoring government entity. The credit rating of the Government of New Brunswick is A+[40]. For projects developed by NB Power, it is assumed that such projects are 80 per cent debt-financed and a loan guarantee of 0.65 per cent applies. The return on equity for NB Power was assumed to be similar to the return on equity (ROE) allowed in the Open Access Transmission Tariff for capital of 10 per cent. It is assumed an investor-owned utility would have a debt ratio of 60 per cent with a levered ROE of 11 per cent.

Table 5.1 shows two calculations of WACC. One represents a publicly owned Crown corporation like NB Power. The other represents a private investor-owned company. In the IRP, NB Power assumes the WACC for is 5.99 per cent versus 7.68 per cent for investor-owned utilities. A lower WACC results in a lower overall cost to New Brunswickers for a given project.

6 Fuel and Electricity Market Price Forecast

NB Power runs a diverse power system that results in a direct dependence of various sources of fuel (e.g. coal, heavy fuel oil, light fuel oil, natural gas and nuclear). NB Power is also subject to commodity fuel prices through power purchase agreements and wholesale market electricity purchases.
With a diverse fuel mix, NB Power can often mitigate the price risks associated with individual commodities. The fuel mix is complemented by a comprehensive hedging strategy to reduce risks from short-term variations in fuel and electricity market prices and better plan for impacts on electricity prices.

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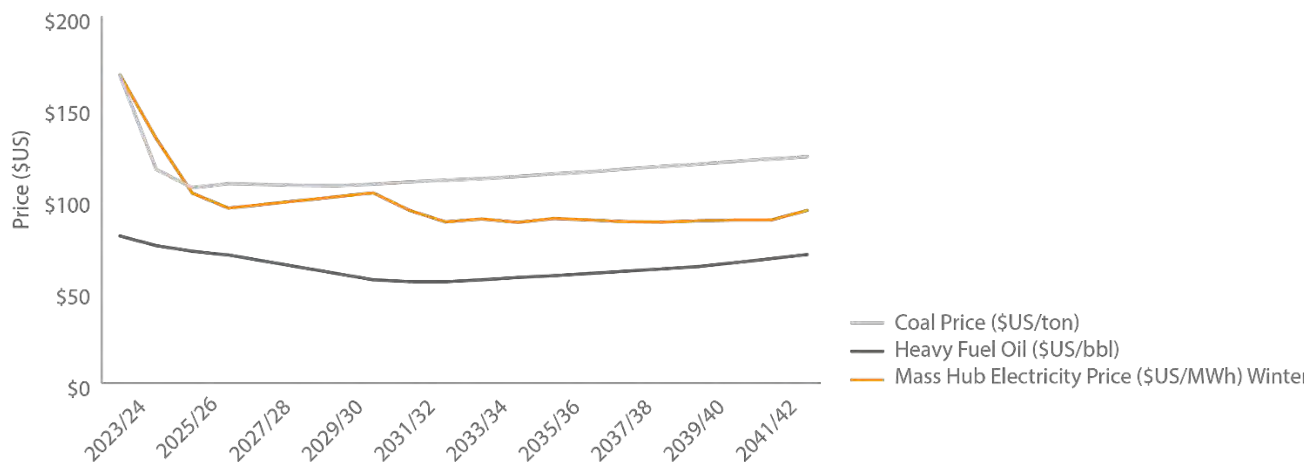
[36] *Conference Board of Canada Quarterly Rates Data/Forecast Published October 2022.*
[37] *LTD rates are the sum of CBOC CAD long-term rates and PNB spreads retrieved from Bloomberg November 2022.*
[38] *Based on an internal analysis of Canadian Bond rates (October 2022).*
[39] *Credit ratings retrieved from Bloomberg February 2023.*
[40] *Credit ratings retrieved from Bloomberg February 2023.*

To develop a fuel price forecast for the IRP, NB Power used a combination of forward prices from the 2023/24 NB Power budget and long-term forecasts developed by its fuel price forecasting consultant, Energy Ventures Associates updated in October 2022. Figure 6.1 and Figure 6.2 shows select data from the resulting fuel price forecast. Fuel price forecasts do not include the cost of transportation or other costs and fees that would be applicable to NB Power, such as carbon taxes as these costs are included in the modeling assumptions.

Figure 6.1: Fuel & Electricity Price Forecasts

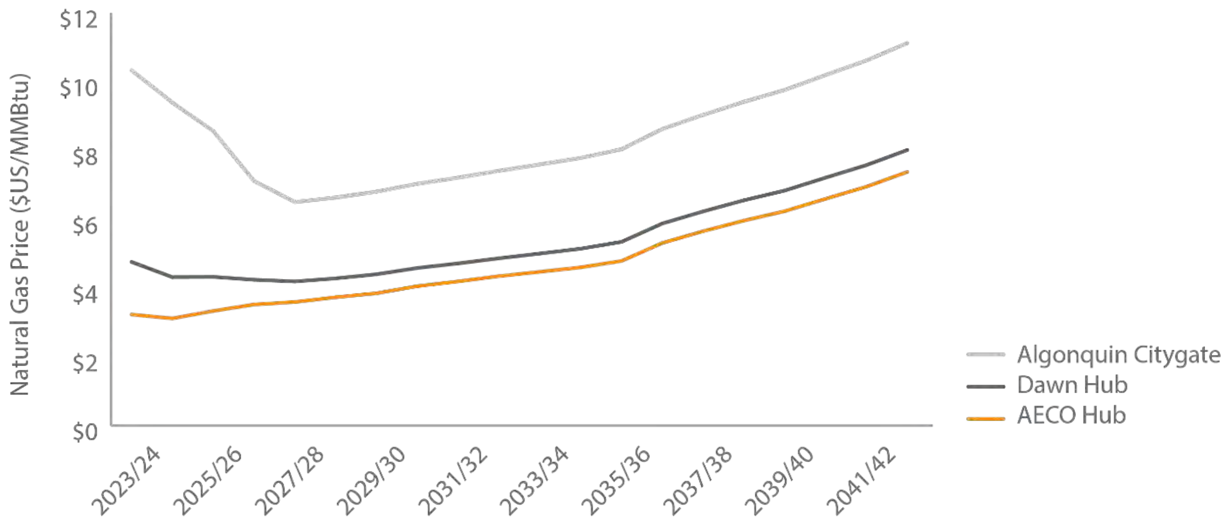


Fuel prices continue to be higher in the short term due to continued geopolitical events. However, over the long term it is expected that commodity prices will return to normal levels.

The electricity market prices shown in Figure 6.1 are Massachusetts Hub (Mass Hub) prices. These are highly correlated to natural gas prices. The Mass Hub price index is a key indicator for any electricity imports or exports that NB Power purchases or sells in the wholesale market. Heavy fuel oil is the primary fuel used by the Coleson Cove Generating Station. Coal is the primary fuel used by the Belledune Generating Station until 2030.

Natural gas is used by Grandview as well as the Bayside Generating Station. Recent high natural gas and Mass Hub prices caused by geopolitical issues are expected to continue in the short term. However, over the long term it is expected that commodity prices will return to normal levels.

Figure 6.2: Natural Gas Price Forecasts for Algonquin Citygate[41], Dawn Hub[42] and AECO[43]



The availability of additional natural gas beyond that consumed by Grandview and Bayside generating stations can be challenging during the coldest periods of the year. For energy security purposes, natural gas units are assumed to either require a firm gas transmission path or dual-fuel capability. The ability to generate from both gaseous and liquid fuels will also keep options open for integration of renewable fuels in the future (e.g. biodiesel, renewable natural gas, hydrogen).

NB Power has secured a long-term supply source and the required pipeline reservations to bring competitively-priced natural gas from AECO Hub in Western Canada to New Brunswick. As a natural gas-fuelled station, Bayside offers significant carbon savings over the use of coal and oil and allows NB Power to shift electrical production to this lower emitting station, and thereby plays a vital role in providing reliable electricity while reducing emissions.

Natural gas pricing assumptions used in the IRP depend on the operating characteristics of the generation supply option.

Combined cycle generators are one example. They are relatively efficient and operate at higher capacity factors than other less efficient generators and often need a longer-term, stable fuel supply. This means they require firm commitments on fuel volumes and transportation, which is assumed to be facilitated through the Dawn Hub.

Peaking units operate less often and at irregular periods, therefore spot market gas purchases using the Algonquin Citygate Hub is a more appropriate natural gas price for the purposes of the IRP. Peaking units will also require the ability to be fired from light fuel oil in the case of gas supply issues.

For each source of natural gas, it is assumed that in the long-term prices will stay competitive compared to other fuel sources such as heavy fuel oil and electricity market prices. NB Power continues to look at other natural gas sources and transportation options.

[41] *Algonquin Citygate is a natural gas trading hub located in Massachusetts.*
[42] *The Dawn Hub is a natural gas trading hub located in southwestern Ontario.*
[43] *AECO Hub is a natural gas trading hub located in southern Alberta.*

7 Load Forecasts

NB Power produces an annual load forecast, which projects New Brunswick's electricity requirements into the future, for the purposes of budgeting and planning for the future. The foundation of the 2023 IRP is based on the NB Power Load Forecast 2023-2033, completed during the spring of 2022. In this IRP, the low electrification scenario is aligned to the Load Forecast 2023-2033 while the high electrification load forecast includes increased opportunities for electric vehicle loads and industrial electrification. The following sections describe the low electrification load forecast by customer classification with the high electrification additions.

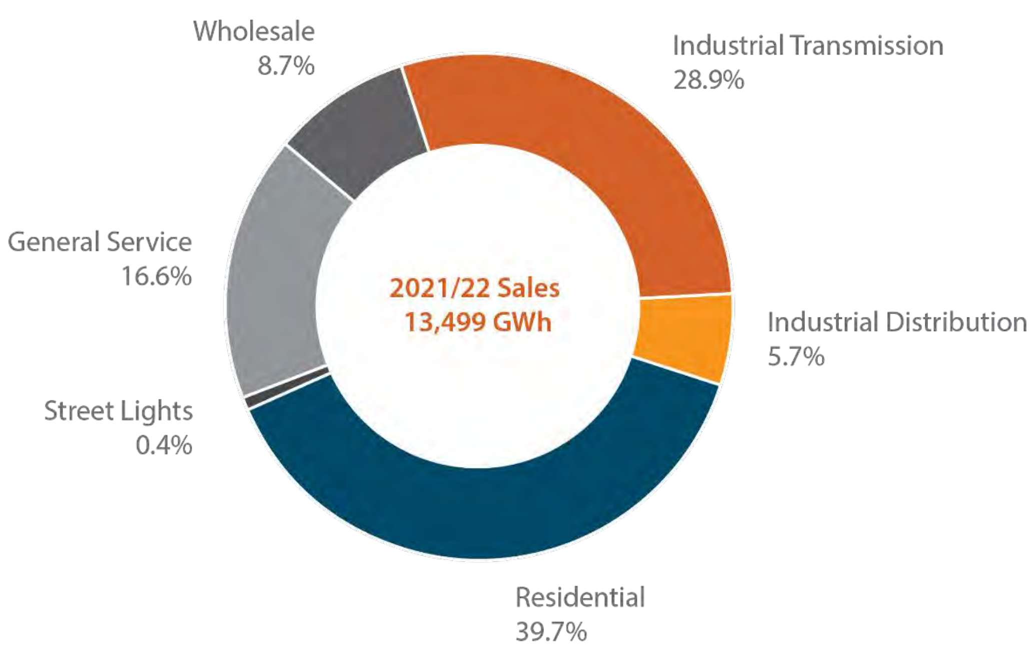
7.1 Customer Classifications

The load forecast groups customers in six customer classifications, based on their electricity consumption patterns and types of end-uses, with customers in each group impacted by similar factors (e.g., weather, economic activity). The six customer classifications are

1. residential
2. general service
3. street lighting
4. industrial distribution
5. industrial transmission
6. wholesale (which includes sales to customer classifications noted above by municipal utilities in Saint John and Edmundston)

Figure 7.1 shows the relative proportions of NB Power's energy sales in the 2021/22 fiscal year to each of the six customer classifications.

Figure 7.1: 2021/22 Total Sales

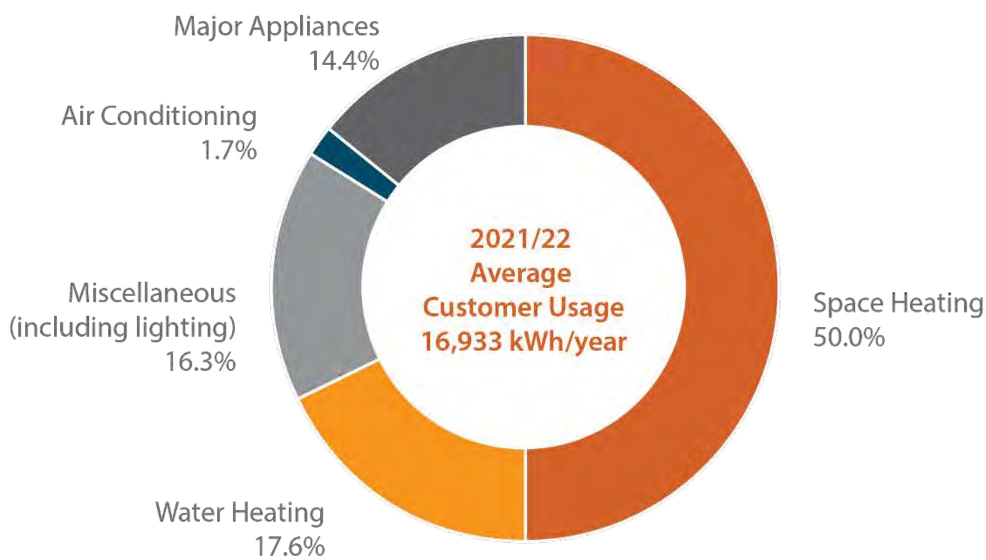


7.2 Residential

Typically, New Brunswick households make up over 95 per cent of the residential group.

In the 2021/22 fiscal year, residential customers made up 44 per cent of the total in-province electrical energy sales (40 per cent directly by NB Power and 4.4 per cent by wholesale utilities).
Residential electricity consumption is forecast using an end-use model that forecasts the consumption of individual appliance types and aggregates them for the customer class. Average household energy use includes electric space heating, water heating and other uses (appliances, lighting, cooling).

Figure 7.2: 2021/22 Average Residential Customer Use



In 2021/22, there were approximately 360,000 year-round residential customers in New Brunswick served directly or indirectly by NB Power. Of those, 320,000 were direct NB Power customers and 40,000 were municipal utility customers in Saint John and Edmundston.

Growth in the residential forecast is driven by the addition of new customers. Growth in the number of customers is driven by population growth, in addition to the societal trend of smaller household size, resulting in the same population being spread over more homes. Increasing average customer use is offset by demand-side management programs delivered by NB Power and naturally occurring, energy efficient choices made by customers.

Residential water and space heating in NB is largely electrified. Over 90 per cent of homes in NB already use electric water heaters. Approximately 70 per cent of homes in NB already use electricity as their primary heating source, with many more relying on electricity to supplement other heating sources.

As requirements for space-heating in New Brunswick continue to electrify, growth in electricity requirements from switching from oil, natural gas, or wood to electric are offset from energy efficiency and switching from electric baseboard to electric heat pumps across the province. Heat pumps are more efficient than baseboards, electric furnaces, or similar heating systems, cutting consumption by about half. Roughly, for every conversion from non-electric to heat pump in NB, there is a conversion from baseboard to a heat pump resulting in little to no net change in overall electricity consumption for residential space heating. The large volume of conversions to heat pumps is resulting in increases to peak demand in both the winter period to meet space heating needs and summer period to meet cooling needs.

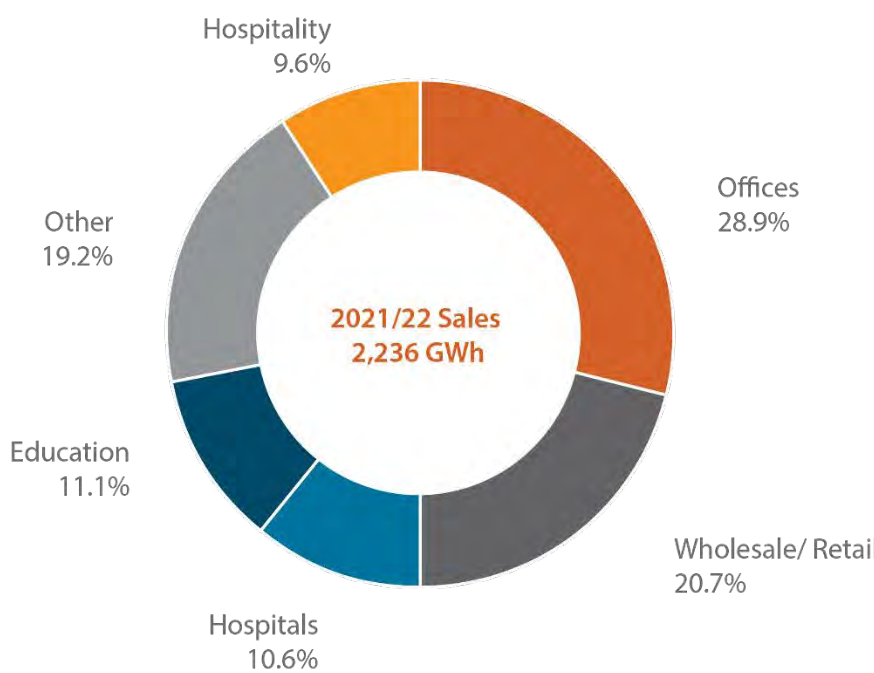
7.3 General Service

The general service classification includes commercial (retail, hospitality, offices, etc.) and institutional customers (hospitals, schools, universities, etc.).

As of March 2022, NB Power served approximately 27,000 general service customers while, New Brunswick wholesale utilities served approximately 5,000 general service customers, for a total of 32,000.

In the 2021/22 fiscal year, general service energy requirements made up 21 per cent of the total in-province energy sales (17 per cent directly by NB Power and four per cent by Wholesale utilities). Figure 7.3 shows the amount of NB Power's total general service sales by sector.

Figure 7.3: 2021/22 General Service Sales



Approximately 30 per cent of general service sales are to the institutional sector. The remaining general service sales in New Brunswick reflect the level of commercial activity and are closely related to the provincial gross domestic product (GDP). Weather affects the amount of electricity required for heating or cooling. The general service forecast uses an econometric model to relate changes in the level of sales to changes in the provincial GDP and the number of heating degree days.

7.4 Industrial

New Brunswick's industrial customers account for about 35 per cent of the total in-province energy use.

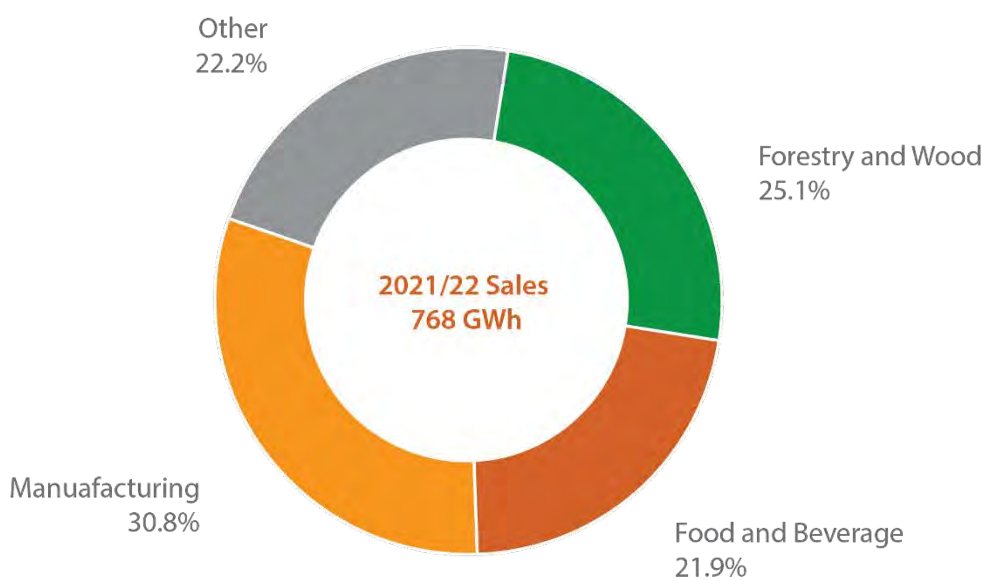
Industrial customers are divided into two groups

- industrial distribution customers (served at transmission voltages less than 69 kV)
- industrial transmission customers (served at transmission voltages of 69 kV and above)

7.5 Industrial Distribution

NB Power serves approximately 1,800 industrial customers at distribution voltages (less than 69 kV), while wholesale utilities serve approximately 70 others, totaling 1,870. Together, they account for approximately 6 per cent of the total provincial electrical energy requirements.

Figure 7.4: 2021/22 Industrial Distribution Sales

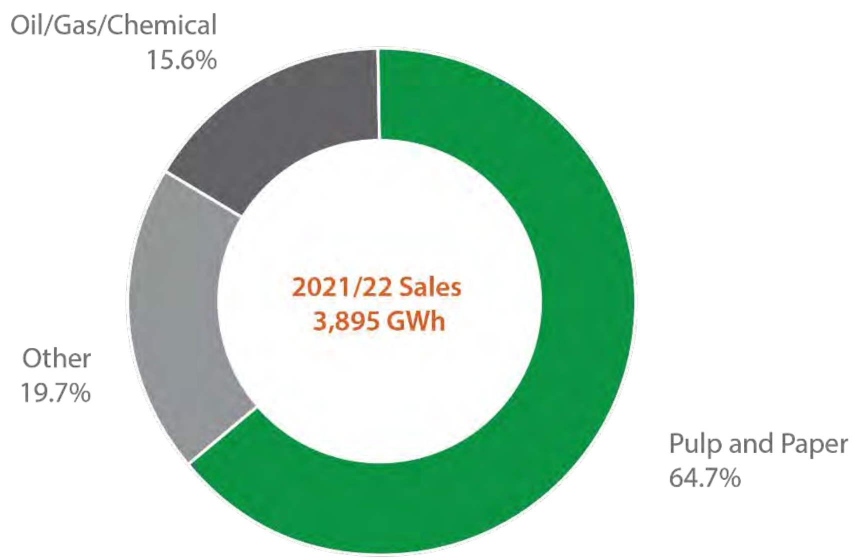


The industrial distribution forecast uses an econometric model to relate changes in the level of sales to changes in the provincial GDP. Increases in the forecasted GDP growth will result in corresponding increases to industrial load growth.

7.6 Industrial Transmission

There are 45 industrial customers served at transmission voltages (69 kV and above). These customers make up most of the industrial sales. Figure 7.5 shows the 2021/22 portions of total industrial transmission sales to each of the main industry groups.

Figure 7.5: 2021/22 Industrial Transmission Sales



The forecast for these customers is done using a bottom-up methodology where each customers' requirements are forecast individually. Adjustments such as growth for electrification or reductions for energy efficiency are then added to the cumulative total.

7.7 System Losses

Delivering electricity from generation sources to customers happens in three stages

- high voltage transmission
- transformation to lower voltages
- distribution to the customers at standard service voltages

There are losses at each of these stages. Many factors play into losses such as the physical distance from the generation source to the customers, technical characteristics of the transmission and distribution systems and load level.

The basis of the forecast energy losses on the transmission system is the Open Access Transmission Tariff[44] loss factor of 3.3 per cent. This amount is assumed to remain constant over the forecast period. Loss factors or percentages are multiplied by the amount of energy delivered over the system to meet NB Power's total energy requirements.

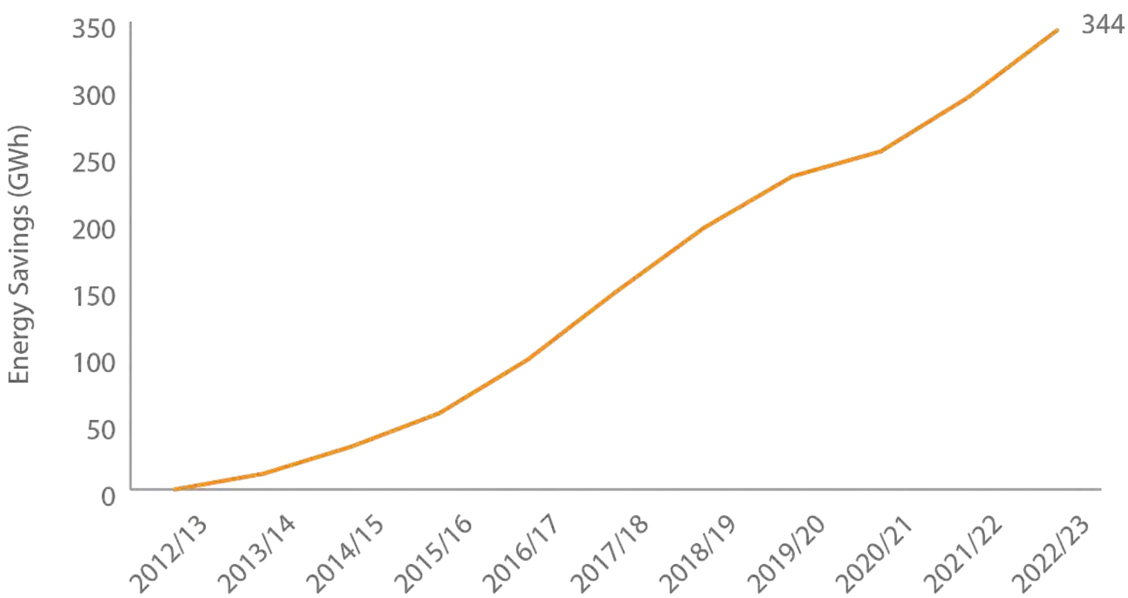
Distribution losses are forecast based on an analysis of the energy supplied over the distribution system compared to billed distribution sales. Energy losses on the distribution system are estimated to be 3.9 per cent of the total distribution sales over the forecast period. In addition, a substation transformer loss factor of 0.6 per cent is applied to all distribution energy requirements, for a total of 4.5 per cent.

[44] *The NB Power OATT provides a real power loss factor, which is applied to all transmission service within NB and is subject to approval by the New Brunswick Energy and Utilities Board.*

7.8 Demand Side Management

Through investments in energy efficiency programs, NB Power has seen over 344 GWh of savings achieved between 2012/13 and 2022/23.

Figure 7.6: Historical DSM Savings



The government of New Brunswick has regulated energy efficiency targets growing to 0.75 per cent of sales in 2028/29 and each year thereafter, as outlined in Table 4.1. These programs will help customers manage their energy costs and lower overall energy requirements over the period by approximately 11 to 14 per cent in 2042/43. Projected energy savings for the forecast period are presented in Figure 7.11.

7.9 Peak Demand

Peak demand is a critical factor to consider when planning for system operations and new supply sources. Peak demand is the maximum energy requirement on the system during a one-hour period.

As a winter peaking utility, NB Power commonly experiences the highest peaks in January and February, which are the coldest months the province faces. It is during these coldest months that New Brunswickers rely heavily on their heating systems to help keep their homes and businesses comfortable.

As electric space heating is currently the most common heat source in homes and businesses in the province, this heating load is a significant driver for demand contributing to NB Power's peak in the winter months and is expected to continue. The growth of high efficiency heat pumps will reduce overall energy consumption but have less of an impact on peak demand. During the coldest temperatures, the efficiency of heat pumps decline and some homes and businesses will require supplemental heat from other sources.

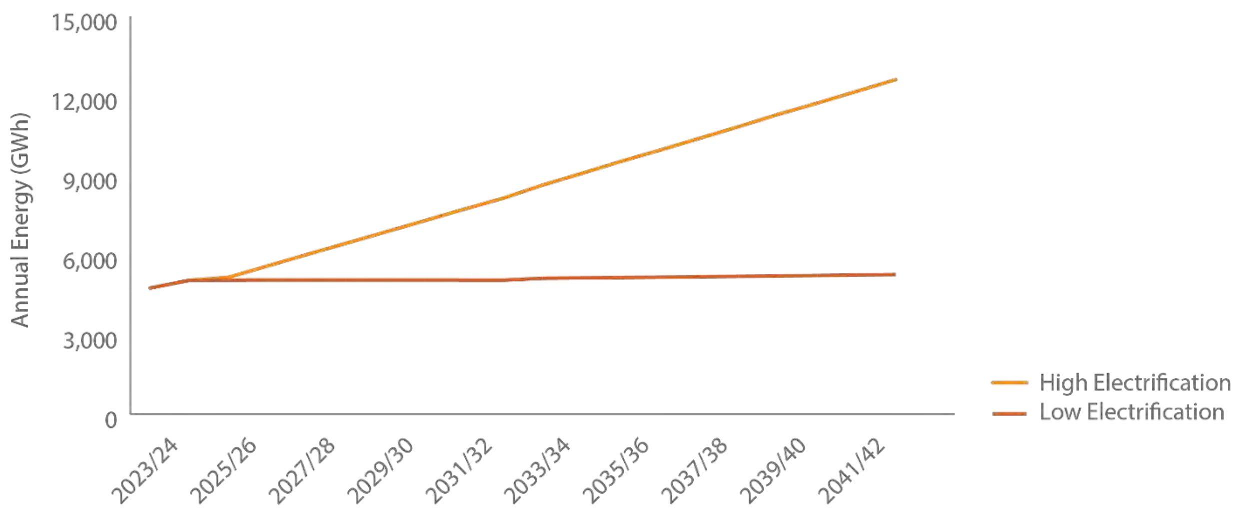
7.10 Low and High Electrification Scenarios

The total customer load is determined by combining the total electricity consumption of the six customer classifications and the transmission and distribution losses related to delivering that electricity. Beyond 2032/33, the forecast is escalated by class, with time-series regression models to project future load growth. Using forecasts for each customer sector, the data is combined to create the total in-province load forecast. The forecast includes estimates of conservation measures that consumers are anticipated to implement on their own without a demand side management program offering from NB Power.

7.10.1 Industrial Electrification

In the low electrification load forecast, an unallocated growth factor of 0.5 per cent was applied annually to account for additional industrial load growth (including electrification). The low electrification load forecast does not take into consideration potential large, new loads such as hydrogen/ammonia production, the emergence of other new industries or firm export sales. The high electrification load forecast adds 1,000 MW between 2025/26 and 2042/43 to represent the potential of emerging industries or firm export sales. The breadth of these forecasts is intended to capture the uncertainty around the potential volume of new industrial loads in the future.

Figure 7.7: Projections of Industrial Energy Sales



7.10.2 Electrification of Transportation

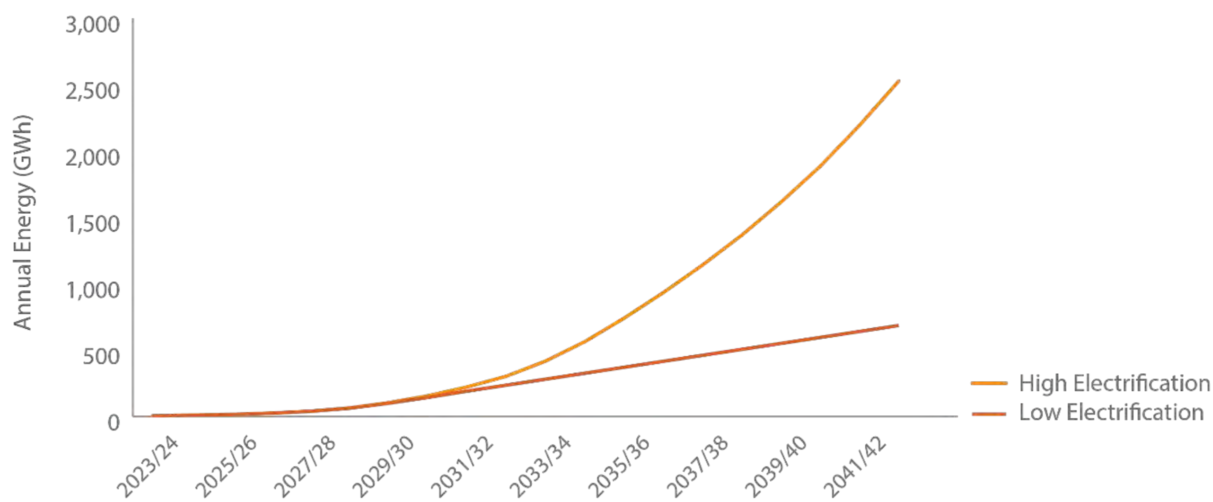
The growing electric vehicle industry is expected to have an impact on energy and demand forecasts in New Brunswick into the future. Table 7.1 provides a comparison of electric vehicle (EV) penetration in the low and high electrification load forecasts. 80 per cent of light duty vehicle (LDV) charging was assumed to occur at home and 20 per cent as general service sales. Medium-heavy duty vehicle (MHDV) charging is expected to occur as general service, industrial distribution, or industrial transmission sales.

Table 7.1: Electric Vehicle Penetration

Year	Low Electrification Load Forecast		High Electrification Load Forecast	
	LDV	MHDV	LDV	MHDV
2023/24	3,101	-	3,101	-
2032/33	80,000	-	97,987	626
2042/43	151,384	-	435,475	22,885

Figure 7.8 shows the combined annual energy requirements for LDVs and MHDVs high projection and the load forecast projection. The high electrification scenario aligns to the federal target of 100 per cent LDV sales by 2035 and 100 per cent of MHDV sales by 2040. Sales growth in the near term continues to be relatively low due to supply chain bottlenecks and production delays.

Figure 7.8: Projections of Electric Vehicle Annual Energy Requirements



7.11 Final Load Forecasts

Figure 7.9 and Figure 7.10 present the low and high electrification load forecasts net of forecasted energy efficiency programs[45]. These forecasts create the foundation upon which the supply and demand side analyses will be conducted.

Figure 7.9: Provincial Energy Forecast after Energy Efficiency Savings

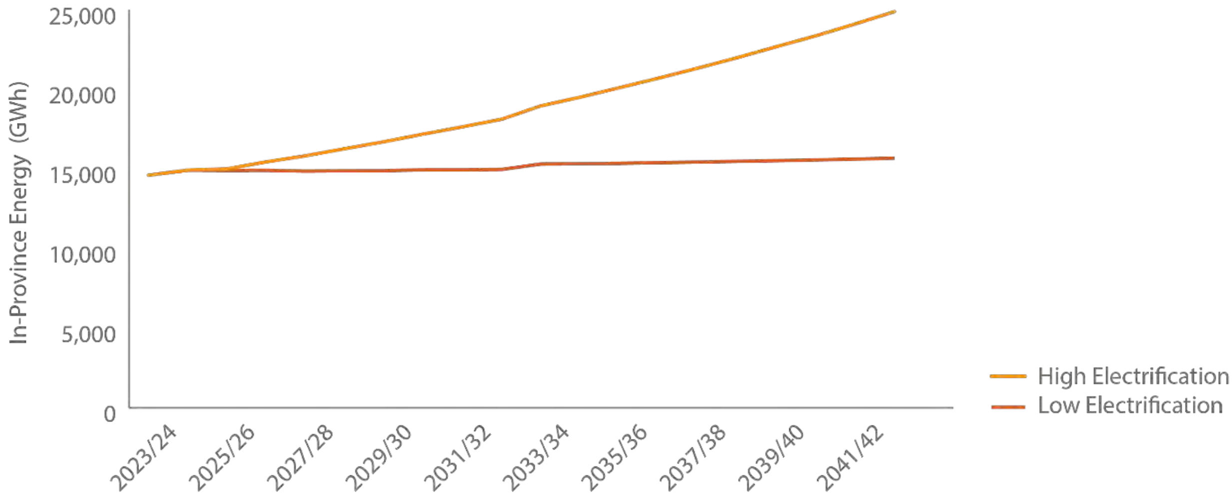
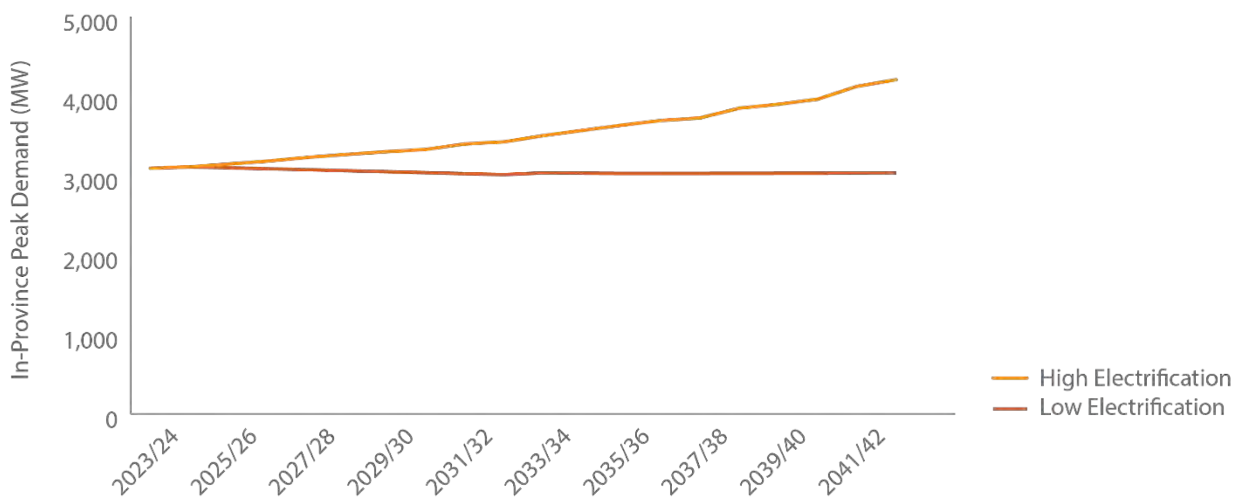


Figure 7.10: Provincial Peak Demand Forecast after Energy Efficiency Savings[46]



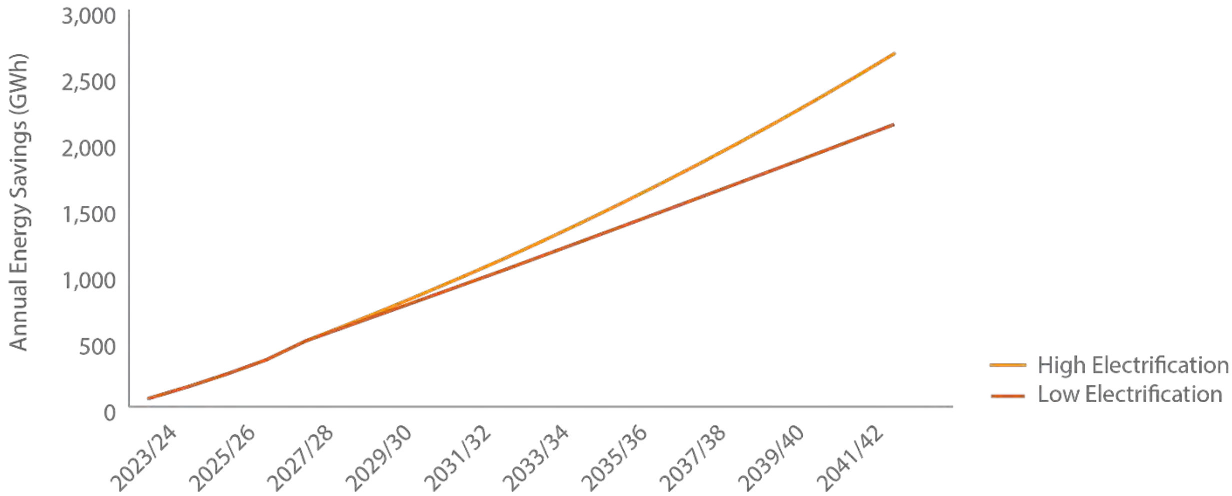
The average growth rate for peak demand is 1.6 per cent per year for the high electrification forecast and flat low electrification forecast. Energy requirements are expected to increase across all scenarios, with considerably more growth in the high electrification forecast. Growth rates for the high and low electrification forecasts are 2.8 per cent per year and 0.4 per cent per year respectively. Detailed load forecast data is included in Appendix B (Load Forecast Details).

[45] *Forecasted energy savings from efficiency programs are shown in Figure 7.11.*

[46] *Detailed transmission studies to determine requirements and costs associated with the high electrification scenario were not included in the scope of the IRP.*

Energy efficiency savings for the final plans are shown in Figure 7.11.

Figure 7.11: Forecasted Energy Efficiency Savings[47]



The impacts of achieving these energy efficiency targets are included in all subsequent tables and figures.

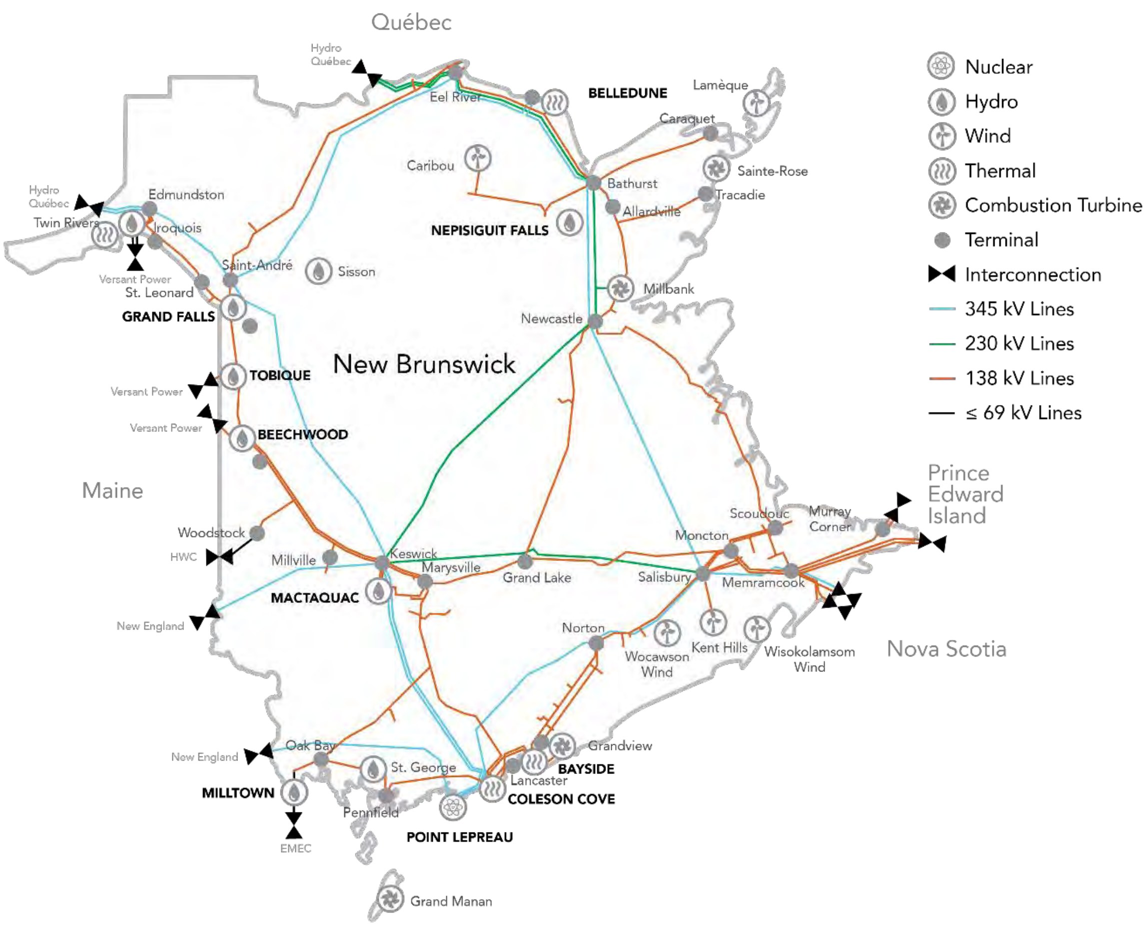
8 Existing Resources

8.1 Generation Resources

NB Power has a diverse mix of generation resources and power purchase agreements. The utility serves the electric needs of the province with hydro, wind, biomass, solar, nuclear, natural gas, oil and coal resources. Over 50 per cent of New Brunswick's energy requirements came from renewable sources in 2022/23. Combining those with the Point Lepreau Nuclear Generating Station results in approximately 75 per cent of New Brunswickers' needs being served from carbon-free sources.

[47] *Total cost of energy efficiency programs over the period are $470 million ($2022 NPV) and $570 million ($2022 NPV) for the low and high electrification scenarios respectively. This is a levelized cost of approximately four cents per kWh.*

Figure 8.1: System Map



At this time, no new generation has been committed for construction. However, at the time of writing, NB Power was evaluating responses to requests for expressions of interest to increase the amount of renewable generation in New Brunswick.

8.1.1 Mactaquac Life Achievement Project

The Mactaquac Generating Station is located on the St. John River, approximately 20 km west of Fredericton, NB. It was commissioned in 1968 and is the largest hydroelectric generation facility operated by NB Power. Mactaquac was designed with an expected service life of approximately 100 years, with an estimated end of service life date of 2068.

The concrete structures at the station are affected by Alkali Aggregate Reaction (AAR). This is a reaction between the alkalis in cement and the silica in the aggregate and causes growth of the concrete, affecting performance of the powerhouse, water retaining structures, gates and generating units. The mitigation of these effects requires more extensive maintenance than normal for structures of this type. Several hundred other dams around the world are also affected by AAR, however Mactaquac is believed to have the one of the highest rates of expansion observed of any other hydro facility in operation. The effects of the expansion have been significant cracking leading to concrete deterioration, strength loss and excessive seepage in the structures. The overall result is a decrease to the 100-year original design service life for the facility to 2030 without significant intervention.

Figure 8.2: Mactaquac Generating Station

In the mid-1980's, an AAR Project Team was formed within NB Power and they have been working since that time to instrument, monitor, model and mitigate the effects of AAR to the structures and the generating equipment. Ongoing mitigation activities have included slot cutting to manage deformation and control stress build ups; concrete coring, extensive grouting and sealing to control seepage; and mechanical interventions to manage the deformation imposed on the generating units and their auxiliaries by the expanding concrete. An AAR board of technical experts was established to consider the appropriateness and effectiveness of the proposed plans and actions taken by the project team and report their findings.

Since 1994, engineering studies have been periodically conducted to determine when the concrete structures including the main spillway, the diversion sluiceway and the powerhouse will need to be replaced or significantly refurbished. These studies have indicated that the existing structures will need to be replaced or refurbished by approximately 2030. Additionally, the turbine-generator units and related auxiliary equipment will have reached their anticipated end of useful life by that time and require major refurbishment or total replacement. The main dam, which is an earth embankment structure, is not affected by AAR.

Recent planning phase activities for the MLAP included the completion of condition assessments for the facility. The findings from the current assessment confirmed that the concrete structures and major equipment at the Mactaquac will reach the end of their useful service life by approximately 2030 and will require either major rehabilitation or replacement.

In 2016, NB Power recommended proceeding with a project to rehabilitate the station and achieve the original end of life target of 2068. The final decision on the project will be made by the provincial government in the near future. The MLAP has been the base assumption in prior IRPs and continues to be the assumed path for Mactaquac in the base scenarios in Section 11. Section 12.1 explores the counterfactual where Mactaquac is retired at the end of 2029.

8.1.2 Bayside Generating Station

The Bayside Generating Station is a natural gas-fired combined cycle power plant located in Saint John. In 2022, NB Power installed a new natural gas turbine increasing the unit's efficiency. While the Bayside Generating Station's expected end of life is in 2038, the new gas turbine's life could be extended beyond 2038 with minimal investment.

8.1.3 Belledune Generating Station

The Belledune Generating Station is the only coal-fired facility in NB Power's diverse system. The facility provides a low-cost source, reliable of supply during the winter period in New Brunswick. In December 2018, the federal government announced plans to phase-out coal as a fuel for electricity generation by 2030. In the Climate Change Action Plan 2022-2027, the Government of New Brunswick is looking to set a clear path to phase out coal in New Brunswick. To meet these objectives, NB Power is exploring fuel-switching options, such as sustainable biomass and natural gas, that would meet New Brunswick and federal clean energy regulations and allow NB Power to continue operating up to its expected retirement date in 2040.

8.1.4 Other Generating Stations

The current net generation capacity and power purchase agreement portfolio, as well as other statistics of the NB Power system, is provided in Table 8.1.

Table 8.1: Existing NB Power Generating Capacity and Other Statistics

Generating Capacity Thermal		
Coleson Cove	972	MW
Belledune	467	MW
Bayside	284	MW
Total Thermal	1,723	MW

Generating Capacity Hydro		
Mactaquac	668	MW
Beechwood	112	MW
Grand Falls	66	MW
Tobique	20	MW
Nepisiguit Falls	11	MW
Sisson	9	MW
Milltown	3	MW
Total Hydro	889	MW

Generating Capacity Nuclear		
Point Lepreau	660	MW

Generating Capacity Combustion Turbines		
Millbank	397	MW
Ste. Rose	99	MW
Grand Manan	29	MW
Total Combustion Turbines	525	MW

Total Generating Capacity		
Thermal	1,723	MW
Hydro	889	MW
Nuclear	660	MW
Combustion Turbines	525	MW
Total Generating Capacity	3,797	MW

Power Purchase Agreements (PPAs)		
Kent Hills (Wind)	167	MW
Caribou Mountain (Wind)	99	MW
Lameque (Wind)	45	MW
Wisokolamson Energy (Wind)	18	MW
Grandview (Natural Gas)	95	MW
Twin Rivers (Biomass)	39	MW
Irving Pulp & Paper (Biomass)	33	MW
AV Nackawic (Biomass)	26	MW
AV Cell (Biomass)	21	MW
Edmundston Hydro	9	MW
Other Renewable	21	MW
Total Power Purchase Agreements	588	MW

Number of Lines		
Distribution Lines	21,358	km
Transmission Lines	6,905	km

Exporting and Importing Capacity		
Export Capacity	2,538	MW
Import Capacity	2,448	MW

Number of Customers	
Direct Customers	362,513
Indirect Customers	47,381
Total Customers	409,894

This diverse mix of generation capability is expected to meet New Brunswick's electricity requirements well into the future. In addition to the generation resources above, NB Power also has interconnections with neighbouring utilities in Québec, Prince Edward Island, Nova Scotia and New England. The interconnections provide NB Power with flexibility to import electricity to offset higher cost generation, export surplus energy and increase system reliability.

For accounting purposes, each generating station is depreciated consistent with its assumed technical useful life based on typical experiences for that type of facility. Power purchase agreements have set contract terms and are generally tied to the useful lives of the contracted facilities. In actual practice, retirements are dependent on a technical and economic evaluation for each unit as it approaches the end of its useful life. In this IRP, retirement schedules are based on a useful life, with consideration of a reasonable extension period that allows the facility to continue operations.

The Clean Energy Regulation (CER) is expected to impact the operational profiles of Bayside and Coleson Cove generating stations, but not to force the stations to retire. The CER would allow the stations to continue to operate at reduced outputs to integrate renewables and maintain reliability of supply in New Brunswick. Consideration of life extension potential is made through studies conducted by NB Power engineering experts and associated economic analyses.

The generating station end of life assumptions are shown in Table 8.2. The life expectancy of the Point Lepreau Nuclear Generating Station is based on the number of equivalent operating hours. Currently the plant is licensed to operate for 210,000 hours and additional work is being completed to extend the operating life to 247,000 hours. Based on historical and planned operation the plant would reach 228,000 hours by the end of the period. Based on operating experience at other CANDU reactors and ongoing assessments at the Point Lepreau Nuclear Generating Station, the end-of-life date is assumed to be beyond the planning horizon of this IRP, likely sometime in 2044/45.

Table 8.2: Retirement Schedule

Resource	Fuel Type	Capacity (MW)	End of Life
Grandview PPA	Natural Gas	95	2024/25
Grand Manan	Diesel	26	2025/26
Bayside	Natural Gas	285	2037/38
Millbank	Diesel	397	2030/31
Ste. - Rose	Diesel	99	2030/31
Point Lepreau	Uranium	660	2044/45
Belledune[48]	Coal/Other	467	2040/41
Coleson Cove	Oil	972	2040/41

Except for Milltown, it is assumed that all hydro facilities will continue to operate through the planning horizon. Renewable PPAs are assumed to be extended, at competitive market prices.

[48] *Coal is phased-out at Belledune in 2030*

8.2 Net Metering

NB Power's net metering program allows customers to produce up to 100 kW of their own qualifying renewable energy from sources like biogas, biomass, solar, small hydro or wind. A bidirectional meter records both the electricity delivered to the customer and the electricity NB Power receives back from the customer's generation unit. This allows New Brunswickers to offset their energy consumption. To qualify for the program, the requirements detailed in the Government of New Brunswick's *Electricity from Renewable Resources Regulation* must be met. NB Power currently has 5.6 MW of installed generation under the net-metering program. This is expected to grow considerably over the period, with forecasts ranging from 300 to 700 MW by 2043.

8.3 Embedded Generation

The embedded generation program allows developers and independent power producers to connect environmentally sustainable generation to NB Power's distribution system. The utility purchases energy from these producers at an established rate. NB Power currently has 20 MWs of embedded generation under contract.

8.4 Transmission & Interconnections

NB Power's transmission system is made up of 6,900 kilometers of transmission lines, terminals and control equipment. It's designed to provide reliable energy to New Brunswick customers and allows the utility to export and import energy to and from neighbouring utilities.

The existing transmission system has evolved over the past century. It began mainly as 69 kV lines connecting small generating stations in municipal distribution systems in the first half of the twentieth century. Following the Second World War, and to keep up with the load growth through the 1960s, the 138 kV system was expanded to form a figure-eight network around the province and interconnect with Nova Scotia for the first time. Expansion continued in the early 1970s with the completion of a 230 kV system connecting from the northeast (Dalhousie-Bathurst-Newcastle) area to Keswick in the west and across the province to Salisbury in the southeast. The maximum system voltage increased to 345 kV with the completion of the New England interconnection and the Coleson Cove Generating Station in the late 1970s. Through the 1980s and 1990s, the 345 kV system expanded to encircle the province and extend into Nova Scotia.

New Brunswick's transmission system is a small section of a much larger bulk transmission system (the Eastern Interconnection) which spans from Central Canada to the Atlantic coast (excluding Québec), south to Florida and west to the Rockies (excluding Texas). Having strong interconnections with neighbouring systems is very important to NB Power. New Brunswick is well positioned with direct interconnections to Québec, Prince Edward Island, Nova Scotia and New England. Interconnected transmission lines and an Open Access framework are used to transfer electricity from one jurisdiction to another under strict rules that maintain open, fair and reliable service. These lines also support the system with direct and indirect contributions to capacity reserves. This lowers costs for New Brunswickers as it lowers the need for additional generation capacity to be committed and online at any given instant to serve customers.

New transmission requirements are driven by several potential factors, including

- the need to connect new generation
- in-province load growth
- import and export requirements
- system reliability
- industry reliability standards
- customer-driven requests
- generator additions and retirements
- changes in locations of future generation sources (e.g. wind and solar)

NB Power regularly assesses the transmission system to ensure it meets reliability standards and provides benefits to New Brunswickers and other customers.
Currently, while meeting adequacy requirements, in-province and customer load requirements place strain on the transmission system. NB Power is aware of transmission constraints within some parts of New Brunswick and NB Power is looking at solutions to address these issues. They include

- adding transmission infrastructure
- targeted demand reductions (smart grid technology/ DSM programs)
- strategically locating any new generation

Future decisions around Belledune or Mactaquac have a significant impact on transmission requirements to maintain system reliability.

Opportunities also exist to increase transmission interconnection capacity with neighbouring jurisdictions. This would enable increased energy imports into New Brunswick from Québec and into Nova Scotia from New Brunswick. NB Power is a participant in the federal government's Atlantic Loop initiative[49], which looks to define what transmission upgrades are required to deliver clean power from Québec or Newfoundland and Labrador to the Maritimes. For more details on the Atlantic Loop project, refer to Section 12.3.

The next 20 years (and beyond) could see changes to generation supply types and locations. These changes may require new transmission infrastructure to reinforce and support current transmission infrastructure. Specific transmission projects, beyond standard new unit interconnection costs, are generally outside of the scope of the IRP, but the results of the plan will help inform future transmission projects. Early discussion with Indigenous communities and key stakeholders is critical to the success of future transmission and generation projects.

9 Capacity Planning

9.1 Capacity Planning Reserve Criteria

NB Power must deliver safe and reliable power to New Brunswickers. This includes the reliable operation of transmission, distribution and generation resources. Generation reliability criteria are governed by a metric known as loss of load expectation. This is the expected number of days each year when the available generation capacity is not enough to meet the daily load demand. NB Power is a member of the Northeast Power Coordinating Council and this council sets reliability practices that interconnected electricity systems follow. The Northeast Power Coordinating Council sets a benchmark of a loss of load expectation of no more than 0.1 days per year[50].

NB Power is the reliability coordinator for the Maritimes Area. The reliability coordinator is responsible for reporting to the Northeast Power Coordinating Council that reliability standards for the region are being met. A recent assessment of the reliability of the Maritimes Area[51] showed a loss of load expectation of 0.01 days per year. This is well below the Northeast Power Coordinating Council reliability benchmark, more than meeting the criterion.

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[49] *"Atlantic Growth Strategy – Clean Energy," Atlantic Canada Opportunities Agency, Government of Canada, March 1, 2019, https://www.canada.ca/en/atlantic-canada-opportunities/news/2019/03/atlantic-growth-strategy--clean-energy.html.*

[50] *"Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System," Northeast Power Coordinating Council, Inc., revised December 6, 2022, https://www.npcc.org/content/docs/public/library/resource-adequacy/2022/2022-maritimes-comprehensive-review-of-resource-adequacy.pdf*

[51] *The Northeast Power Coordinating Council defines the Maritimes Area as New Brunswick, Nova Scotia, Prince Edward Island and Northern Maine.*

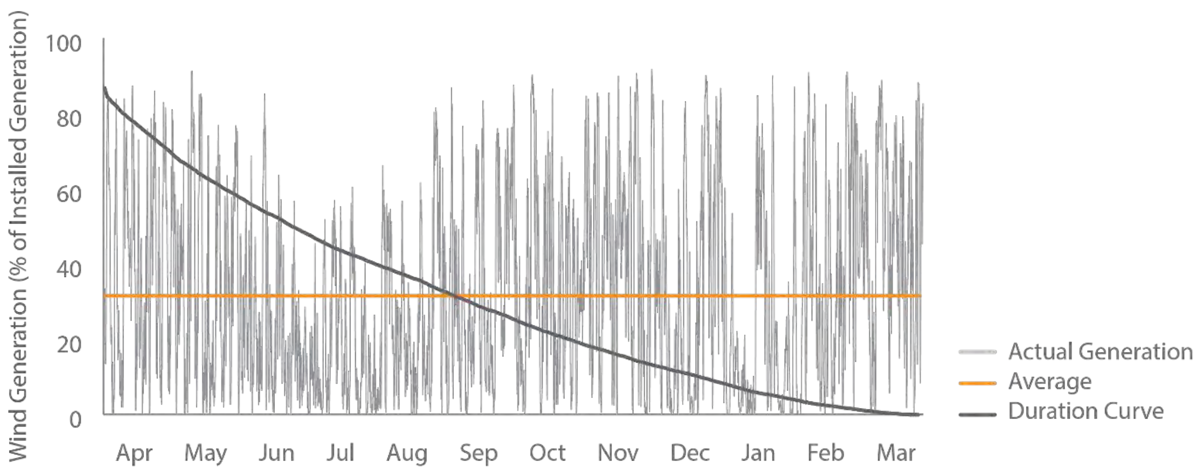
The same study indicates that the minimum reserve criterion for the Maritimes Area is 20 per cent. This means the capacity of generation resources must exceed the maximum firm peak demand by a minimum of 20 per cent in order to have sufficient generation available to meet reserve requirements. The IRP uses this 20 per cent reserve margin to plan for generation capacity.

9.2 Intermittent Resources

NB Power has power purchase agreements for 352 MW of wind generation installed in the province. Wind generation is a valuable resource and it helps NB Power meet the 40 per cent renewable portfolio standard. Wind is also an intermittent resource, with variable and largely unpredictable generation.

Figure 9.1 shows that in 2020, New Brunswick's wind farms, which had a total capacity of 352 MW, operated at less than one-third capacity for more than half of the hours in the year. During those same hours they also produced less than a quarter of their total annual wind generation. The 352 MW of installed wind creates an average daily ramping requirement of 292 MW. This highlights the challenges of balancing intermittent resources such as wind or solar. Additionally, any thermal units needed to meet the next day's peak demand, balance load or balance renewables must remain online even in hours when they are not needed, as these units cannot be cycled on and off daily.

Figure 9.1: 2020 Wind Output Duration Curve[52]



Beyond balancing generation, there are complications with wind that arise in low load conditions. NB Power's system requirements can sometimes be as low as 850 to 900 MW on mild summer nights. There are many generating stations and contracts that can't be ramped down for these low load periods (e.g. Point Lepreau Nuclear Generating Station (660 MW), run-of-river portion of the hydro system (100-150[53] MW) and other must-take contracts (up to 588 MW), for a total of up to 1,402 MW). This can result in forced export sales for minimal revenue or forced curtailment with no revenue. These conditions add to the average energy price for this type of generation. NB Power must consider these low load conditions when looking at the costs and benefits of adding variable renewable resources, like wind or solar.

[52] The 2020 capacity factor was 32 per cent. Improvements in wind technology have increased the efficiency and expected capacity factors of future projects (estimated at 40 to 45 percent).
[53] 100-150 MW represents the portion of the Hydro system that is run-of-river during periods of relatively low hydro flows. Rain, snow-melt or other weather conditions can increase the run-of-river portion considerably. During the spring freshet, the hydro system loses all flexibility and is entirely run of river.

9.3 Planning Capacity Contribution

Intermittent resources present an interesting challenge for capacity planning. Electricity generation from intermittent resources, such as wind and solar, is varied and predictability is difficult. The load forecast error and variability increases as the time from forecast to generation increase. Utilities have no control over when intermittent resources will produce energy as it is dependent on the weather. They generate when the wind blows or the sun shines, regardless of the needs of the system.

Loss of load expectation studies simulate the fleet of generating stations to determine overall system reliability and the ability to serve all customer load. The likelihood of wind, solar and other non-dispatchable technologies being able to contribute toward serving load when needed is considerably less than traditional generating stations. The correlation of generation between sites (wind, for example) also limits the contribution of that technology.

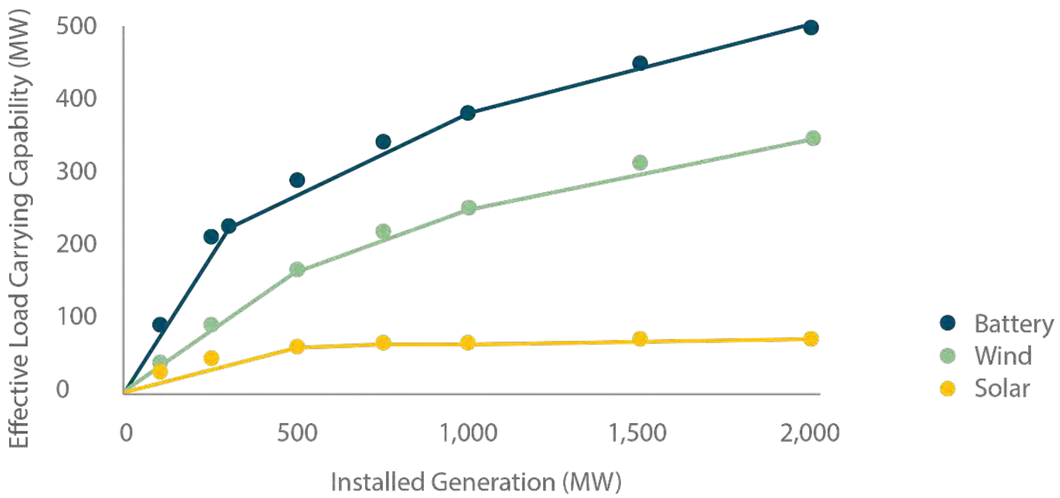
While batteries are dispatchable resources, their limited energy storage also can limit their ability to provide energy to the grid during times of need. For example, if a battery were being used to meet on-peak needs during the day and a generation outage occurred while the battery was depleted, it cannot put energy onto the system. Also, during long periods of cold weather, the system may need energy for more hours than the battery can provide. These factors limit the effective load carrying capability (ELCC) of battery storage.

NB Power contracted Energy and Environmental Economics (E3) to do an effective load carrying capability (ELCC) study on wind, solar and batteries. ELCC is the measure of the ability for a unit to provide capacity to the grid. Traditional generation sources like hydro and thermal resources provide reliable capacity up to their unit maximum capability while non-dispatchable or limited dispatchable units provide less firm capacity to the grid than their installed capacity. The study assessed the effective capacity values of differently sized generators added to the New Brunswick grid.

The study shows the declining effective capacity of these resources as they grow in size. While the initial amounts of generation are reasonably beneficial to the reliability of the New Brunswick system, as they grow in size that benefit declines on a per unit basis. There are a few reasons for this, first due to the correlation of wind generation across the province as you increase the capacity of wind the likelihood of a reliability event being caused by the wind generation increases. Second the duration of low wind events, some lasting days or weeks, requires NB Power to carry ever increasing backup generation capabilities to ensure reliability. In the case of solar, the probable timing of New Brunswick's peak load, usually from 7 to 8 a.m. in the winter, means that expected solar generation would be minimal and would contribute almost nothing to reliability during peak load times.

The analysis shows that the first 250 MWs of batteries provide almost full capacity value, as the installed capacity increases the reliability benefits decrease as we enter diminishing returns. To create a reliable system that meets the NPCC reliability metric of a loss of load expectation of less than 0.1 days per year, NB Power needs to have a variety of generation sources and reliable backup generators. NB Power recognizes that combinations of wind and battery and to a greater extent solar and battery can increase the effective load carrying capacity of the combination above the individual components. However, this difference has no impact on the model at the current levels of battery penetration.

Figure 9.2: Effective Load Carrying Capability (ELCC)

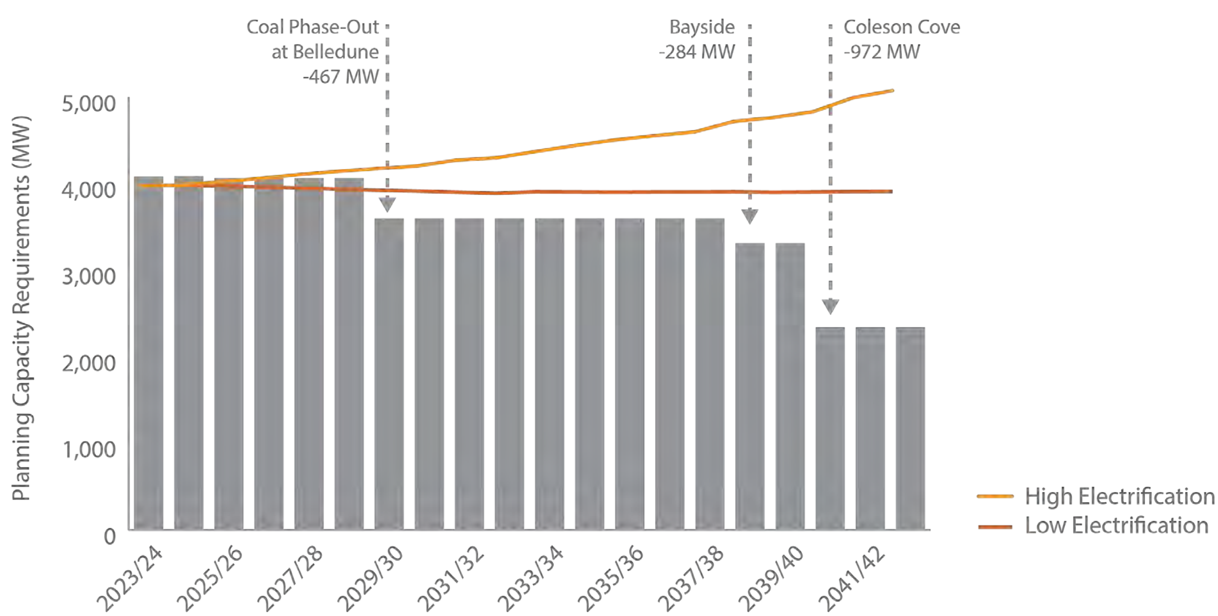


Wind and to a lesser extent solar are excellent sources of low-cost energy, the analysis demonstrates that wind, solar and battery generation provides significantly less effective load carrying capacity per MW of generation as more is added to the system and needs to be supplemented with other forms of generation to maintain energy security.

9.4 Load and Resource Balance

The chart in Figure 9.3 provides a snapshot of NB Power's electricity requirements. Generation resources, as described in Section 8.1 (Generation Resources) are compared to the current load and reserve requirements[54] as well as assumed growth. The load requirement presented is net of energy efficiency programs.

Figure 9.3: Load & Resource Review[55]



[54] NB Power must provide reserve capacity equivalent to 20 per cent of its firm load.
[55] High and low electrification scenario load requirements include 20 per cent reserve margin.

This review indicates that the need for capacity emerges in 2029/30 under the low electrification scenarios. Under the high electrification scenarios, the gap is much larger and there is a need for new capacity by the end of fiscal 2026/27. A reduction in supply resources occurs in 2030 when NB Power must stop burning coal at Belledune Generating Station and find an acceptable replacement fuel or find an alternate source of capacity and energy. The forecasted end of life at Coleson Cove Generating Station in 2040/41 is another large drop in capacity resources and the IRP will solve for the gaps. The clean electricity regulations proposed for 2035 significantly restricts NB Power's fossil fuel generators from generating electricity but will not affect their contribution to capacity as the current understanding of the potential regulations is that they would include provisions for utilities to maintain some fossil fuel generation for integrating renewables and providing reliability.

NB Power currently sells capacity and energy to PEI and Northern Maine. The IRP assumes that these contracts continue through the period. Entering into agreements with neighbouring systems enables NB Power to benefit from economies of scale in construction of new generation sources as well as the ability to potentially market any small surplus capacity volumes caused by load growth volatility to its neighbouring systems. This brings additional value to New Brunswickers offsetting the need for higher electricity rates.

In previous IRPs, NB Power has reviewed the potential to extend the life of the Millbank and Ste.-Rose generating stations to continue providing capacity and emergency energy. Those reviews showed that life extensions to Millbank and Ste.-Rose were the most economic choices, which continues to be the conclusion in this Plan. The extension of these generating stations is included in all scenarios.
As part of the IRP process, NB Power will review the potential life extension of Bayside Generating Station beyond 2037/38, as well as the potential for fuel switching at the Belledune Generating station to allow it to continue operating into the 2030s.

10 Supply Side Resources

10.1 Supply Options

The IRP looks at supply options of varying sizes, fuel sources, technologies, operating characteristics and costs. While the economics of each option are important in order to be consistent with least-cost supply planning, there are other factors that need to be considered such as environmental sustainability and risk management considerations including reliability and dispatch characteristics.

Greenhouse gas emissions, dispatch characteristics and ancillary service capabilities are important considerations, because not all generation supply options are equally capable or contribute to energy security in the same way. Electricity consumption is constantly changing and energy supply must always be in balance with energy demand. NB Power also needs to maintain a minimum level of reserve generation to meet reliability standards. Some generation options are better at these tasks than others.

Generally, a supply option is either considered fully dispatchable (controllable and predictable) or dispatch limited (limited to no control and predictability). Fully dispatchable options can be ramped up or down and can adjust output to meet the requirements of the electrical system. Other generation technologies have limited capabilities, in many cases they are limited to reducing generation to match load but cannot increase generation on demand when load increases. Some generation types have no ability to vary with demand.

Variable renewable generation sources like large wind and solar farms are examples of dispatch limited options. These options are dependent on factors like weather conditions and time of day. Because of that, they're not able to efficiently respond at all times to the consumption needs of New Brunswickers. These resources generate when they can and don't generate when they can't, regardless of the needs of the system. Some intermittent generation like wind and solar now come with options to reduce output from the natural levels. This can offer some controllability by curtailing the energy (i.e. forgoing generation). The costs of curtailment are included in NB Power's models for these resources.

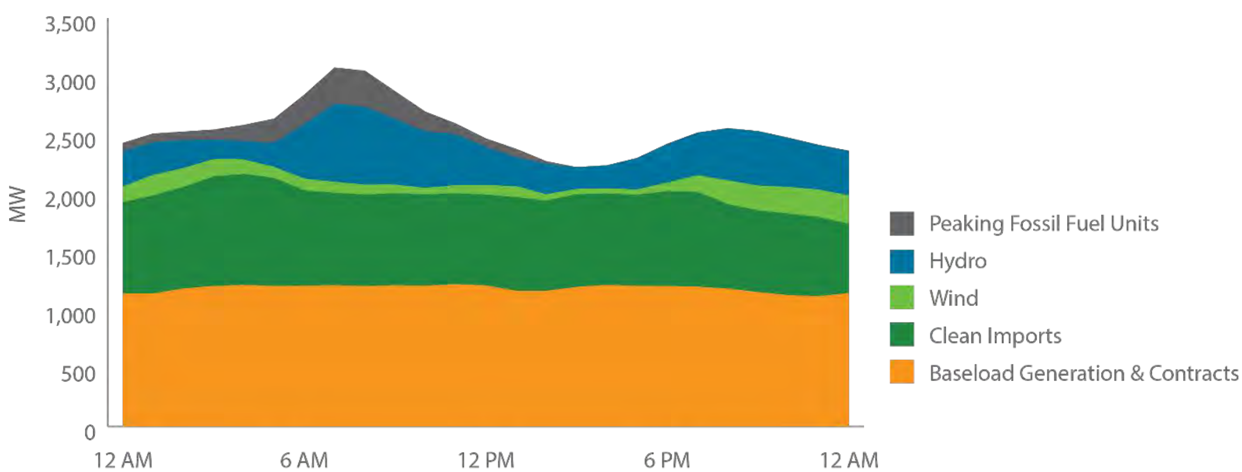
Battery storage is another example of a dispatch limited resource, as their ability to dispatch is dependent on their current state of charge. For example, if a battery was discharged during peak time or for economics at one period of the day, it may be depleted for a generation shortage later in the day. Similarly, a battery that is held for reserve in case of generation outages cannot provide reserve once the battery is discharged until it has been charged again. These limitations reduce the ability of batteries to provide dispatchability at all times.

To make variable renewable generation sources more viable, they are best paired with dispatchable sources, demand side management programs or energy storage to meet demand. The total amounts of this type of generation needs to be studied regularly to ensure system stability and reliability.

On the coldest days of winter New Brunswick experiences periods of peak demand as New Brunswickers turn to electric heating systems to keep their homes and businesses comfortable. During periods of high load, there is a need for dispatchable generation sources that can inject energy onto the grid for relatively long periods of time (i.e. multiple days). This can become a significant challenge after 2035 when meeting the obligations under net-zero energy regulations. In addition, the system needs ancillary services that balance the system and allow intermittent supply sources to be integrated. NB Power requires some amount of dispatchable generation sources to be online to provide synchronous reserves such as load following and regulation services at all times. This requires units with flexible output that can balance load changes or variable renewable resources.

The graph in Figure 10.1 shows a typical peak winter day and how daily energy demand is met with different generation sources.

Figure 10.1: Winter Dispatch Example



In this example, as electricity demand increases in the morning, when New Brunswickers wake up and get ready for work or school, energy output from intermittent wind resources decreased due to changing weather patterns. Fully dispatchable resources (thermal generation and hydro) are then increased to offset the decrease in intermittent resource output and provide the additional generation required to meet the morning peak. Throughout the day, hydro generation is used to meet most of the load following requirements. Baseload generation is met primarily by Point Lepreau, Bayside and Belledune generating stations and energy imports. A second, typically lower, peak occurs in the evening as New Brunswickers return to their homes, have dinner and prepare for the next day. As the evening peak progresses, energy output from intermittent resources increases and energy imports are reduced. During the overnight hours as New Brunswickers sleep, load naturally falls and NB Power lowers output from hydro generation to build up water levels in anticipation of the following days' peak energy requirements.

The clean electricity regulations proposed for 2035 by the Federal Government will significantly impact NB Power system operations. Base load units like Bayside Generating Station will have to limit operations to meet the new requirements. Belledune Generating Station will have to cease burning coal by 2030. Should the Station switch to biomass, fuel cost and availability will likely mean a seasonal operation, prioritizing the high load months in the winter.

In the case of Bayside Generating Station, after 2035, it will be limited to a back-up generator role. In the case of wind and solar, additional technologies will need to be deployed with these units to allow them to operate at less than their natural output. The volume of limited dispatch generation will dictate the needs of the system to curtail this excess generation. NB Power's models evaluate the lost value due to generation curtailment against the cost of storage to determine the least cost dispatch.

The CER is expected to allow the construction and maintenance of low-usage fossil fuel generators to provide back-up power to the grid to integrate renewables and maintain current reliability levels. Combustion turbines are a low-cost capacity source to back up the grid as long as usage levels are below the allowable operating limits. They provide needed reliability with limited capital investment and the technology is mature and predictable. Batteries can also provide capacity and reliability but typically are limited to short periods of generation (less than 4 hours) before requiring charging. Batteries are better at providing ancillary services such as load following and load smoothing than combustion turbines.

10.2 Capital and Operating Cost Assumptions

Cost is a critical piece of the supply-side analysis. It has a significant impact on recommendations made through the IRP process. NB Power engaged a consultant, Energy and Environmental Economics (E3), to provide project and operating cost parameters for potential supply options in New Brunswick. A summary of project cost and operating parameters for each option is provided in Appendix C (Project and Operating Cost Parameters).

In order to support the IRP's principle of risk management, many of the supply options considered in the IRP are types that are in wide-spread commercial operation. However, given the pace of technological change, some supply options that are not currently in wide-spread commercial operation were also considered. The IRP scenarios look at two different technological progress possibilities. In the fast-paced technology development scenarios, E3's projected cost declines for several newer technologies as they either become cheaper or more efficient. In the moderate-paced technology development scenarios it is assumed that costs will increase at the pace of inflation from the current period forward and that any efficiency gains will be offset by cost increases resulting in no real price changes over time.

E3 provided NB Power with capital cost projections for different generation technologies that could be constructed in New Brunswick. The evaluations are based on NB Power's consultant's in-house data from recent similar projects and on publicly available industry data from conferences, reports, professional papers and other publications. Historical project costs were adjusted for inflation to 2022 Canadian dollars as needed. Using all available information E3 created separate cost trajectories for each technology, incorporating expected increased efficiency and reduced cost due to advances in technologies. The cost estimates reasonably reflect the cost of building the generator in New Brunswick. Specific sites were not selected for the alternatives except in cases involving modifications to NB Power's existing generation assets.

Carbon costs are included in the levelized cost of energy estimates and detailed production cost modelling.

Capital costs provided by NB Power's consultant were expressed as overnight costs[56]. Interest rate during construction rates were set at 4.99 per cent, consistent with the interest rate in Table 5.1. Escalation was also applied to capital projects that reflected E3's projected construction escalation rate and projected efficiency improvements. All other costs, including operating, maintenance and administration costs, were projected to increase by 2 per cent per year in 2026 and beyond with higher rates in the short term, based on the consumer price index forecast. Capital cost estimates include system interconnections costs. For more details, refer to Section 5 (Economic Assumptions).

Typical plant operations and operating modes are described in support of the operating maintenance and administration cost estimates. Costs include operators of the facility, maintenance, labour and materials as well as administrative costs to provide the facility service. Operating costs do not include fuel costs. However, information is provided on typical heat rates for each thermal power technology. NB Power estimates the appropriate fuel costs for each alternative using the thermal characteristics of the source and long-term fuel price forecasts provided by NB Power's fuel price forecast consultants.

10.3 Demand Side Resources

In addition to supply options, NB Power also considers demand side resources. Demand side resources include demand response programs, energy shifting programs and modernized rate design.

Demand response programs are programs that can be called on to reduce load on-demand at times of high usage or to respond to sudden losses or generation or high prices. Energy shifting programs are programs that can be scheduled in advance to move energy demand from peak times or times of high prices to periods where the economics are better. Generally, these types of programs are planned days in advance and are not available as emergency response. Alternately, rates can be designed in such a way as to encourage users to alter behaviours moving energy demand from peak periods to off-peak periods. Critical peak pricing and on and off-peak rates are two examples of pricing programs.

NB Power has assumed the availability of 90 MWs of effective capacity demand side resources during the IRP assessment period. The IRP also assumes the demand response programs will take up to 7 years to ramp up to the full 90 MWs, this makes 2030 the earliest the full 90 MWs could be available.

In all demand side programs there is a limit to the total potential load that can be signed up, as the load curve flattens the benefits achieved by shifting or reducing demand diminish. NB Power plans to continue studying these types of programs to develop effective load capacity curves and to identify the total potential volumes of energy for each program. As new and current technologies develop, these numbers will change and NB Power will review the amount of demand response in subsequent IRPs.

[56] *Overnight costs exclude interest during construction and escalation.*

10.4 Small Modular Reactors

Since 2018, New Brunswick has been making progress towards the development and deployment of advanced small modular reactors (SMRs) – the next generation of nuclear technology. This includes forming partnerships with two industry-leading SMR development companies.

The interest in advanced SMRs came from their potential to generate low-carbon electricity safely, reliably and inexpensively. Advanced SMRs are smaller in both size and output compared to conventional nuclear reactors and will leverage factory manufacturing of modules for transportation to sites. This equates to lower capital costs as well as ease of installation and operation. Advanced SMRs boast additional features, such as inherent safety characteristics, integration with renewables and the potential to reduce the amount of existing used nuclear fuel by converting it to clean energy.

NB Power, along with the Government of New Brunswick, have been working collaboratively to progress advanced SMR designs for commercial demonstration in New Brunswick.

Successful completion of the vendor design review process, along with demonstrated technical and financial viability, could result in first-of-a-kind commercial demonstration projects in New Brunswick, consistent with Action 7 of the Government of New Brunswick's Climate Change Action Plan 2022-2027 (refer to Section 4 for more detail).

The development of advanced SMR technology can lead to future fleet deployment opportunities provincially, nationally and internationally; New Brunswick is well positioned to become a hub for supply chain and technical support as technology is deployed. Over the 2020-2035 timeframe, the development of advanced small modular reactors in New Brunswick is projected to create approximately (direct and indirect)[57]

- 730 jobs per year over 15 years
- $1 billion in Gross Domestic Product
- $120 million in provincial government revenue

As there are many changes in the energy sector as well as pressures related to climate change and reducing our carbon footprint, it is imperative that NB Power shows leadership and innovation in finding new sources of energy for our future needs. SMRs are a critical piece of New Brunswick's pathways to net-zero.

The New Brunswick Climate Change Action Plan identifies the construction of two first-of-a-kind small modular reactors (SMRs) in New Brunswick. Aligning with the Climate Action Plan, the IRP builds a minimum of 450 MWs of SMRs in each base scenario. In the high electrification scenarios increased demand requires more generation so up to 750 MWs of SMRs are included. The IRP also examines the effects of different construction dates on system requirements by changing the on-line date of the first SMR from 2030 to 2035[58]. A sensitivity analysis showing the system configuration without SMRs is contained in Section 12.2.

10.5 Distributed Energy Resources

In addition to traditional supply options, NB Power also considers the expanding roles that customers will play in the future. Distributed energy resources are small electrical generators (typically renewable) or energy storage devices. They are connected to the distribution system and are close to the loads they serve. NB Power currently has programs in place that fall into this category. As NB Power continues to modernize the grid there will be more opportunity to integrate distributed energy resource technologies into the distribution system.

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[57] *Small Reactors Big Opportunity, (2021). Retrieved from SMRNB website https://smrnb.ca/wp-content/uploads/2021/02/small-reactors.pdf*

[58] *The IRP does not include any cost estimates for SMRs and they are therefore not treated as an economic supply option in the expansion plan optimization*

NB Power understands some New Brunswickers have a growing interest in producing and storing their own energy but also want reliable backup energy from the grid. To facilitate these interests, NB Power will continue to modernize the New Brunswick electrical system. The utility continues to study viable business models for customer owned generation to support these goals. For the purposes of the IRP, two different levels of distributed energy volumes were integrated into the four scenarios based on the technology development rate. In the rapid technology scenarios, a high level of penetration is assumed. In the moderate technology development, a smaller level of penetration is expected.

10.6 Results of Supply Analysis

The following sections provide detailed analysis for each of the supply options included in the IRP. Each supply option is evaluated using levelized cost analysis. Levelized cost analysis is a methodology used to evaluate the relative economics of generation projects with different sizes, fuel types, capacity factors and useful lives. This analysis acts as a screening tool to decide which technologies should be included as potential options for detailed capacity planning and production cost modelling.

The analysis includes all costs for each project over its lifetime. Specifically,

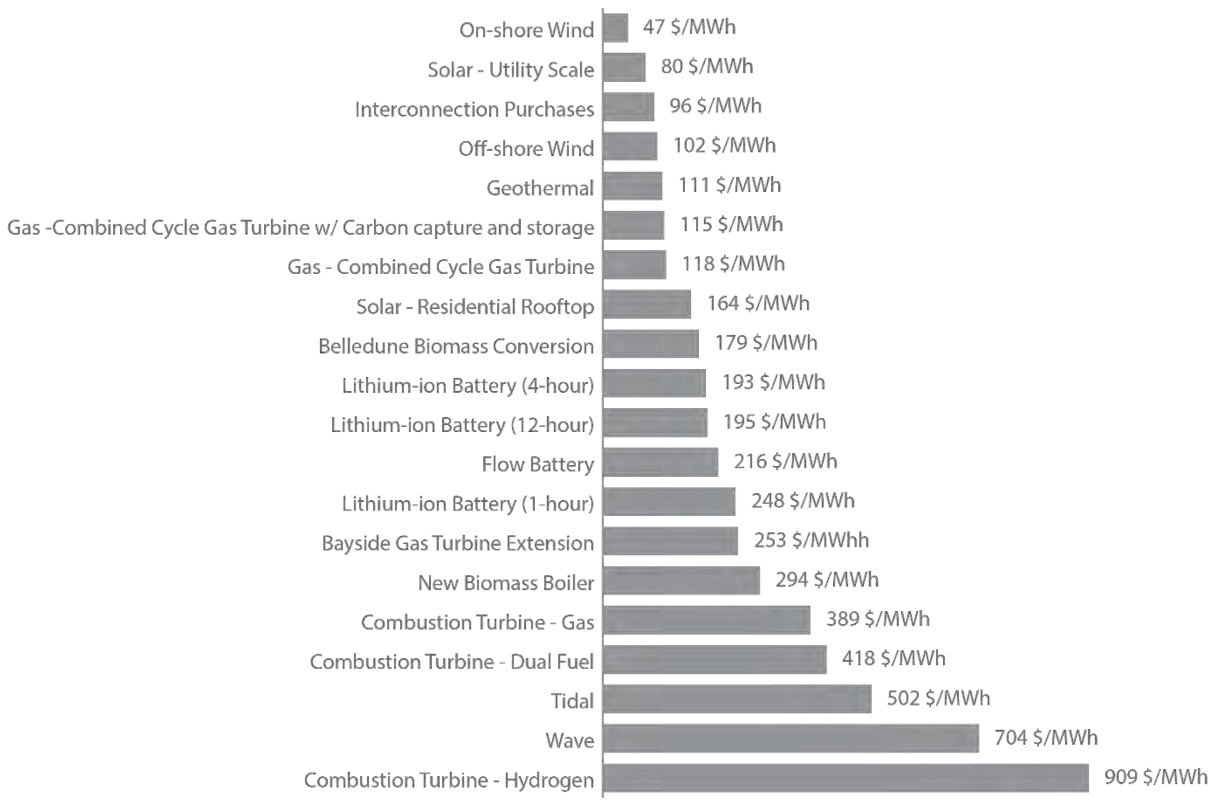
- initial investment costs
- operating, maintenance and administrative costs
- fuel costs (if applicable)
- financing costs
- environmental costs including carbon emissions costs (if applicable)
- balancing/load following adders for intermittent options

Three types of levelized cost analyses are useful in evaluating potential energy sources and capacity against system requirements.

10.6.1 Levelized Cost of Energy

Levelized cost of energy is the average revenue per unit of energy production (expressed as dollars per megawatt-hour (MWh)) required by a project owner to recover all investment and operating costs inclusive of fuel and carbon costs[59]. Levelized costs range from a low of $47 per MWh for on-shore wind options to a high of $909 per MWh for hydrogen-fuelled combustion turbines. The levelized cost of energy analysis identifies the cost at which technologies provide energy to the grid. It does not consider dispatch characteristics, reliability, energy security, load following potential or contribution to capacity requirements.

Figure 10.2: Levelized Cost of Energy ($2022)

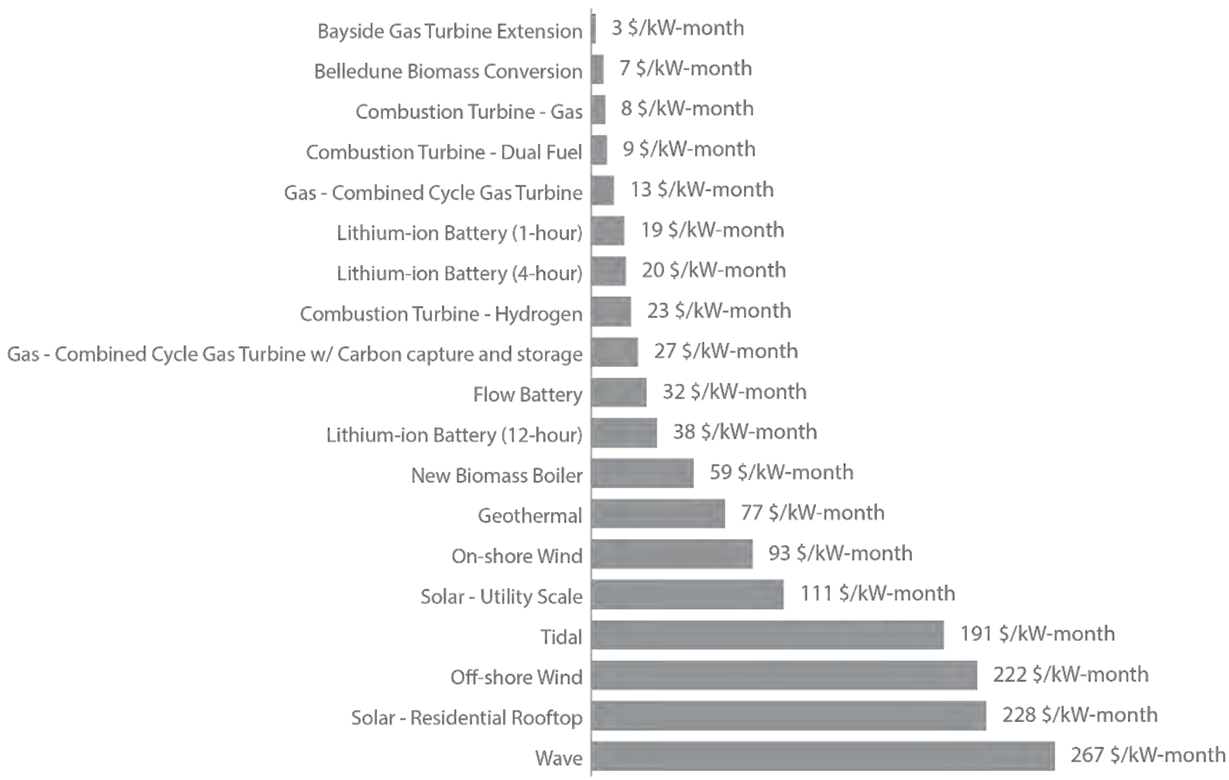


[59] *"Levelized Cost of Electricity and Levelized Avoided Cost of Electricity Methodology Supplement," U.S. Energy Information Administration, July 2013, https://www.eia.gov/renewable/workshop/gencosts/pdf/methodology_supplement.pdf.*

10.6.2 Levelized Cost of Capacity

The levelized cost of capacity is the revenue per unit of capacity (expressed as dollars per kilowatt-month (kW-month)) adjusted for the respective capacity credit for each option that is required to recover all investment and fixed operating costs. NB Power must maintain a level of reserve generation equal to 20 per cent of its firm load. For traditional dispatchable generating technologies, the installed capacity and capacity credit are equal. For intermittent or non-dispatchable technologies, the capacity credit is less than the installed capacity (refer to Section 9.2). This results in a relatively high levelized cost of capacity when compared to dispatchable non-intermittent generation resources. Levelized costs range from a low of $3 per kW-month for the Bayside Generating Station's gas turbine extension to $267 per kW-month for Wave Power. While capacity can theoretically be purchased from neighbouring jurisdictions in the long-term, such purchases are not considered practical or consistent with energy security requirement due to all of NB Power's neighbouring jurisdictions are expecting significant load growth especially in the winter, the time when NB needs capacity the most.

Figure 10.3: Levelized Cost of Capacity ($2022)



10.6.3 Levelized Cost of Energy and Levelized Cost of Capacity of Storage

The cost of storage must evaluate the round-trip efficiency of the system as well as discounting of the installed capacity to account for the system's contribution to load carrying capability. Battery systems do not generate electricity but store previously generated energy then returning it to the grid when needed. This process has losses and different batteries have difference round-trip efficiencies.

To calculate the LCOE for batteries NB Power calculates the average cost of energy during charging, adds the cost of losses during charging, storage and discharge to get an LCOE value for energy discharged to the grid. To calculate the LCOC of storage NB Power takes the expected cost of construction of the storage system divided by the load carrying capability of the battery.

When compared to combustion turbines, one of the lowest cost capacity options, storage options are not cost competitive for low energy capacity usage in the short term but look to become competitive under some scenarios at the end of the IRP review period. The cost and efficiency of storage solutions continues to progress; assuming this, storage solutions begin to be selected at the end of the IRP review period.

10.6.4 Cost of Private Financing

The cost of capital for private power projects is estimated by reviewing recent actual experience of major independent power producers in Canada. With this information, the IRP assumes private projects after-tax weighted cost of capital is 7.78 per cent compared to 5.99 per cent for public projects (Section 5 - Economic Assumptions). On average, the higher cost of private financing increases the levelized costs of energy and capacity for generation supply options by approximately 20 per cent.

There are other factors that can help close the gap between private and public financing. Some renewable energy projects are eligible for grants or certain tax incentives that could help lower the overall cost to rate payers for these projects. Different incentives are available for NB Power-owned versus investor-owned projects, which are often eligible for tax incentives for renewable investment. Private entities can also bring efficiencies and scale to projects.

The ownership structure of the projects has a major impact to NB Power's overall finances, particularly the balance sheet, but it doesn't have a significant impact on the overall revenue requirement for any specific technology. Because of this, NB Power has assumed an NB Power ownership model for all new supply resources except wind and solar projects. NB Power has a history of contracting in-province renewable supply through power purchase agreements and the IRP assumes a similar arrangement.

10.6.5 Levelized Cost Summary

Based on the levelized cost analysis and the load and resource assessment, it is possible to develop alternative system plans that can be evaluated in detail through production cost and financial modelling. System plans need to address renewable portfolio standards, greenhouse gas emission constraints and long-term capital stock turnover.

Supply options show a significant variation in both energy and capacity cost. Screening was based on emission profiles, dispatch characteristics and economics. Emission profiles of each option were reviewed to ensure a sufficient level of carbon-free generation options were made available in the analysis to meet current and future renewable portfolio standard and net-zero targets. Dispatch characteristics of each option were reviewed to ensure the various system and reserve requirements would be met. Finally, levelized costs were reviewed and unique generating technologies with the lowest costs were included in in the initial screening.

Generation technologies with high costs or low costs that are not technically feasible in New Brunswick were screened out. For similar options, only one technology was screened in. For example, the off-shore wind was not selected for further analysis as it is very similar to the on-shore wind option, but with a much higher LCOE.

Based on the results of the levelized cost analysis, system requirements, environmental and dispatch characteristics of each supply option, the following mix of conventional and alternative options were selected for further evaluation using the PLEXOS detailed capacity expansion model

- Grand Falls Additional Power
- interconnection purchase energy only
- Bayside extension– simple cycle gas turbine
- simple cycle gas turbine dual fuel
- gas – combined cycle gas turbine (CCGT)
- Belledune biomass conversion
- gas combined cycle gas turbine with carbon capture and storage
- gas combustion turbine using hydrogen
- onshore wind
- solar – utility tracking
- small modular reactor
- lithium-ion battery (4-hour)

11 Analysis & Results

11.1 Methodology

Consistent with the *Electricity Act* and the 2020 IRP, this IRP uses the least cost-of-service and greenhouse gas emission impacts as key metrics. Least cost-of-service is measured by taking the present value of the estimated annual partial revenue requirements[60] over 20 years for each expansion plan. Emission impact is determined by calculating the total emission output for each plan over the 20-year planning horizon. All plans are developed in a way that meets renewable generation requirements and adheres to regulations on managing greenhouse gas emissions.

NB Power uses a software application called PLEXOS to determine the least-cost expansion plan. PLEXOS is a production simulation model used by utility companies to optimize near-term planned operations and long-term expansion planning.

To develop the least-cost plan, all reasonable and feasible supply-side and demand-side alternatives are provided as inputs and run through PLEXOS LT model. This allows the utility to find the least-cost plan that meets forecasted electricity requirements within New Brunswick while meeting all policy objectives. The results are then run through PLEXOS MT/ST to determine the operational feasibility of the plan. The MT/ST module is a chronological, hourly simulation that accounts for energy security through the provision of ancillary services, unit commitments and ramping constraints among other items (e.g. state of charge for battery objects). This ensures that the least-cost plan reliably meets future load requirements, environmental constraints and generation reliability requirements.

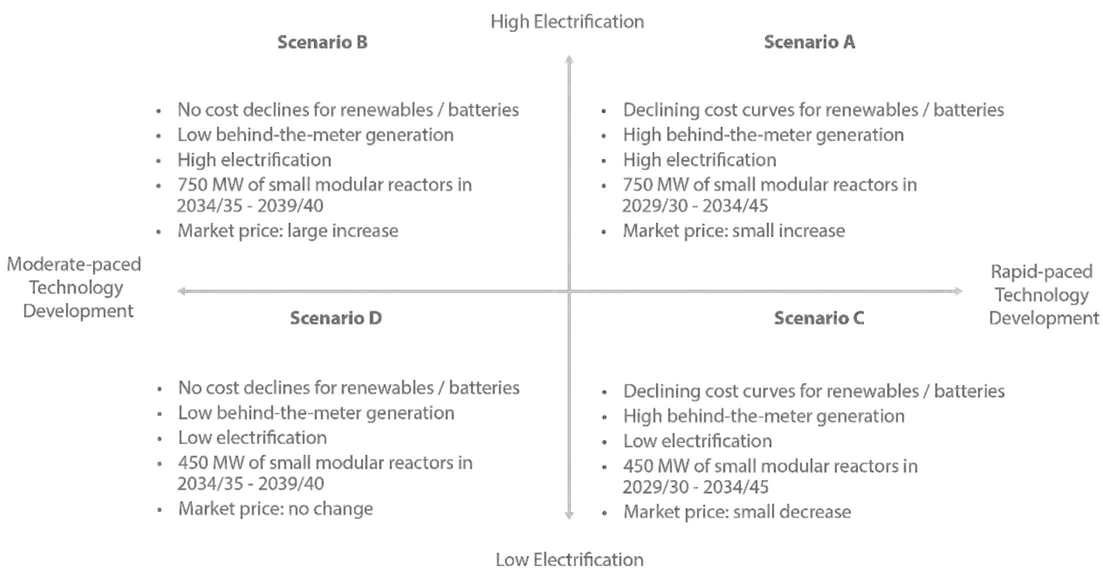
Operational feasibility checks are completed for capacity based ancillary services including automatic generator control, load following, spinning and supplemental operating reserves[61]. To the extent possible, transmission related constraints and costs are included in the analysis. However, fulsome transmission system operations and integration studies are not within scope and upgrades to the transmission system may be required to maintain reliability and power quality.

[60] *Partial revenue requirement is defined as the total revenue to be recovered from in-province electricity customers. This differs from traditional revenue requirement in that it is reduced by miscellaneous and export revenues.*
[61] *For additional details on reserves, refer to the NB Open Access Transmission Tariff, Schedules 3, 5 and 6. https://tso.nbpower.com/Public/en/docs-EN/tariff/TransmissionTariff_20230101_EN.pdf*

11.2 Scenario-Based Approach

The electricity industry is changing and the future is highly uncertain. In an effort to evaluate many possible futures, NB Power used a scenario approach for the IRP. Four different scenarios were created that create a range of assumptions where most likely futures reside. The table below provides a summary of the scenarios with more detail for each in the following sections.

Figure 11.1: Scenario Summary



11.2.1 Generation Technology Capital Costs

Two scenarios were developed for generation technology capital costs to represent the uncertainty in costs as these technologies continue to mature. In the rapid technology development scenarios (A and C), the cost curves showing the dashed lines were used[62]. These curves decline until the early 2030s and then rise modestly through the balance of the period. In the moderate technology development scenarios (B and D), the 2022 cost estimates were escalated at CPI, as shown by the solid lines below. These curves are meant to represent a future where raw material costs or supply bottlenecks push overall costs up as demand for renewables accelerates globally. The two scenarios should serve as upper and lower bookends to help determine the overall sensitivity to capital cost of the projects.

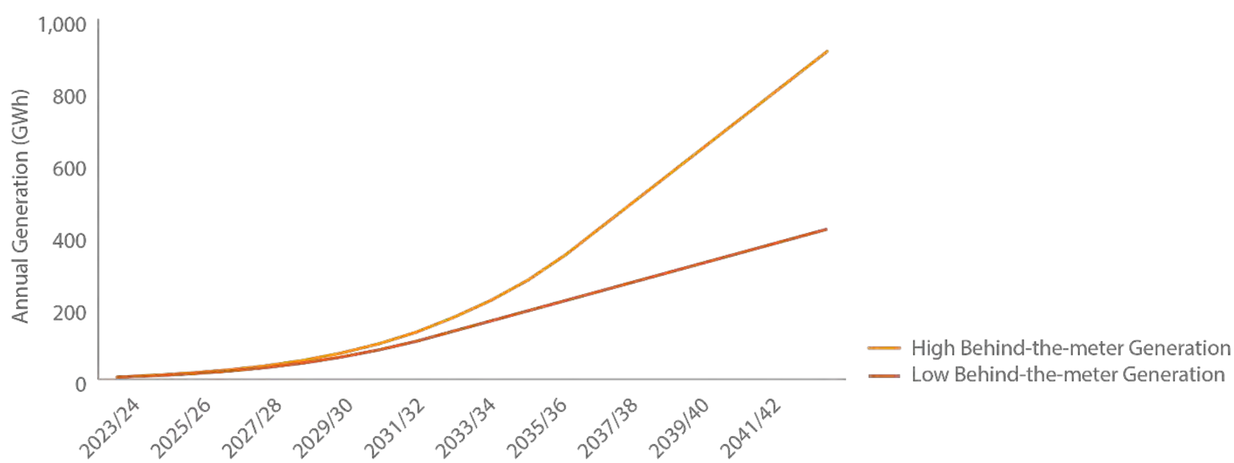
[62] *Projected cost curves based on external consultant (E3) report. Refer to Sections 10.2 for more detail.*

Figure 11.2: In-Service Capital Cost for 100 MW Project

11.2.2 Behind-the-meter (BTM) Generation

The rapid technology development scenarios (A and C) include increased penetration of BTM generation by customers through rooftop solar or other means. The projections for the low and high BTM generation are presented in Figure 11.3.

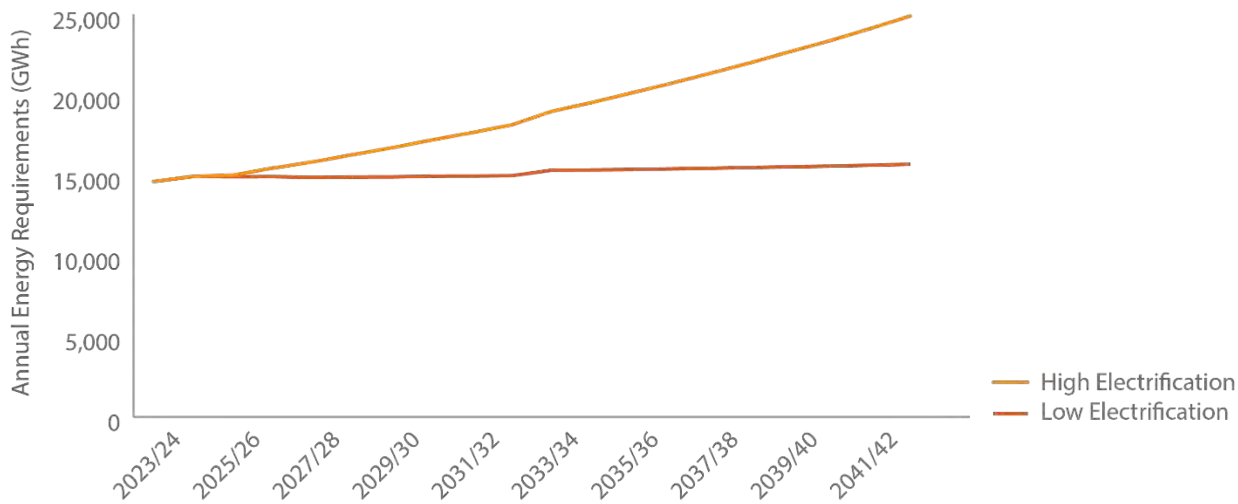
Figure 11.3: Behind-The-Meter (BTM) Generation Scenarios



11.2.3 High and Low Electrification Impacts on Load Forecast

The pace and scale of electrification in New Brunswick could lead to very different energy requirements. The combination of growing energy efficiency targets mandated by the province as well as natural efficiencies driven by new building codes and standards or appliance improvements could significantly limit growth over the planning period. On the other side, growth in electricity use for transportation or industrial processes could drive large increases. The details of the high and low electrification forecasts are provided in Section 7.10 with overall energy requirements for New Brunswick shown below.

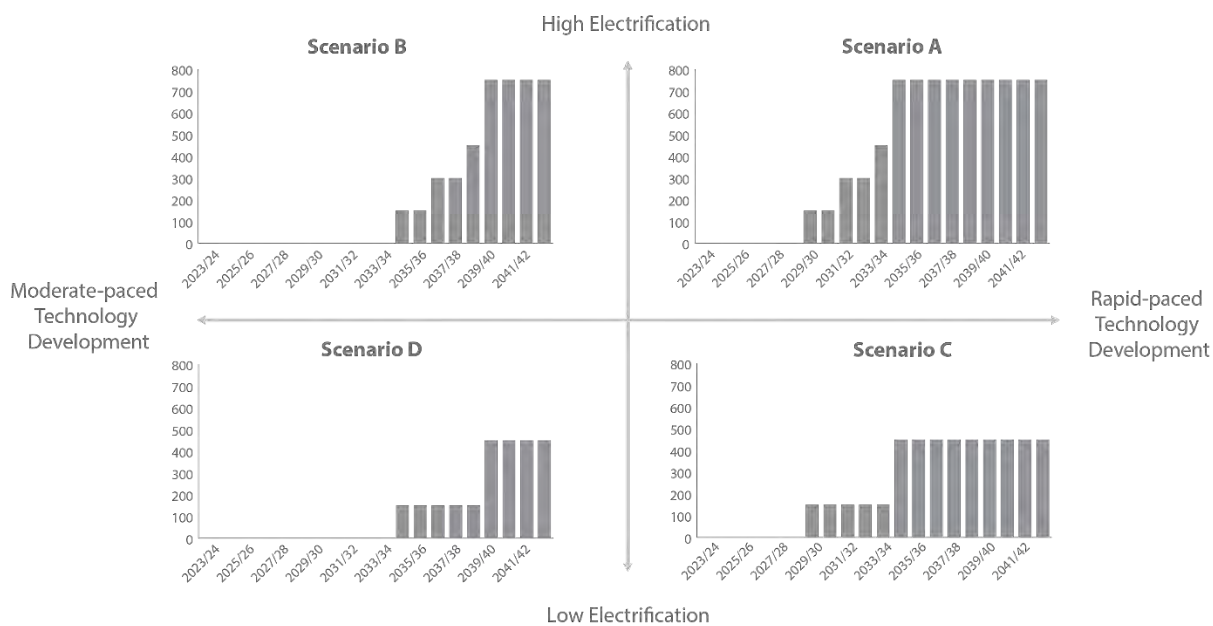
Figure 11.4: Total In-Province Energy Requirements



11.2.4 Small Modular Reactor (SMR) Rollout

Advanced nuclear or small modular reactors (SMRs) represent a burgeoning industry with a high potential to lower global emissions by providing stable and reliable baseload, non-emitting electricity generation. The Climate Change Action Plan 2022-2027 action 7 (see Section 4.3) looks to develop a clean electricity strategy, inclusive of two first-of-a-kind SMRs to help decarbonize New Brunswick's electricity sector. This IRP has integrated the uncertainty associated with SMRs into the scenarios by varying the timing and total quantity. In the rapid technology development scenarios (A and C), the SMRs become operational in the 2029/30-2034/35 horizon. In the moderate-paced technology development scenarios (B and D), it is assumed that the rollout occurs in 2034/35-2039/40. The quantity of SMRs, among other factors, depends on the pace and scale of decarbonization. In the high electrification scenarios (A and B), 750 MW of SMRs are installed through the planning horizon, with only 450 MW installed in the low electrification scenarios (C and D).

Figure 11.5: SMR Rollout by Scenario



Section 12.2 also explores a sensitivity without SMRs in order to determine what generation sources are offset by SMRs and to identify what additional issues could arise.

11.2.5 Market Price Adjustments

Wholesale market electricity prices are subject to considerable fluctuations and variations. It is assumed that these prices will be influenced by increased electrification in New Brunswick by putting additional pressure on wholesale electricity prices in the region. The availability of low-cost renewables should help push in the opposite direction, reducing the pressure on wholesale electricity prices. These factors are assumed to push market prices up or down throughout the period, depending on the scenario, as shown in Table 11.1.

Table 11.1: Electricity Market Price Adjustments by Scenario

Scenario	Pace of Technology	Electrification	Electricity Market Price Adjustment
A	Rapid	High	+10%
B	Moderate	High	+20%
C	Rapid	Low	-10%
D	Moderate	Low	No adjustment

11.3 Results – Base Scenarios

The future of electricity in New Brunswick is driven by the Clean Electricity Regulation (CER) outlined in Section 4.3. It creates the conditions where two types of generation resources thrive: non-emitting technologies to provide energy to the grid and peaking resources to ensure reliability. All scenarios include new wind resources of at least 300 MW by 2027/28.

In Scenarios A and B, where total electricity requirements see considerable growth, large volumes of wind are required by the end of the planning period (1,900 MW and 1,800 MW respectively). While this generation helps provide energy to the grid, its ability to contribute toward reliability is limited (see Section 9.2).
Solar is also present in Scenarios A and B, playing a similar role to wind generation.

With large volumes of wind integrated into the system, the reliability challenges NB Power faces come during periods of low wind generation. During these times, NB Power relies on increasing market imports and increasing generation from dispatchable sources such as hydro units, battery storage, or peaking thermal plants.

After 2035, peaking thermal plants such as Millbank, Bayside extension or new dual-fuel combustion turbines (CTs) have a limited number of hours that they can be online in any given year, creating a significant challenge to meet energy requirements through prolonged periods of low wind and high load.

SMRs and the Belledune biomass conversion option help manage this issue as they provide predictable and reliable electricity to the grid regardless of the weather and without the volume constraints that emitting plants face under the CER.

11.3.1 Expansion Plans

The expansion plan required to meet the peak requirements is summarized in the following series of charts. Figure 11.6 shows the effective (firm) capacity of each resource to show that each scenario meets its reliability criteria.

Appendix D includes tables with detailed expansion plans for each scenario.

In each case we see significant capacity contributions from SMRs, dual-fuel combustion turbines (CTs) and the Bayside Generating Station extension option. Belledune biomass conversion is present in scenarios A, B and D. Demand response programs occur by the end of the period in each scenario.

The contribution of wind, solar and battery storage toward effective capacity is reduced from the installed capacity in accordance with the effective load carry capability (ELCC) analysis discussed in Section 9.2. The actual installed capacity of each unit is shown in Figure 11.7. This provides a view of the significance of these technologies, particularly onshore wind.

Figure 11.6: Effective (Firm) Capacity by Scenario

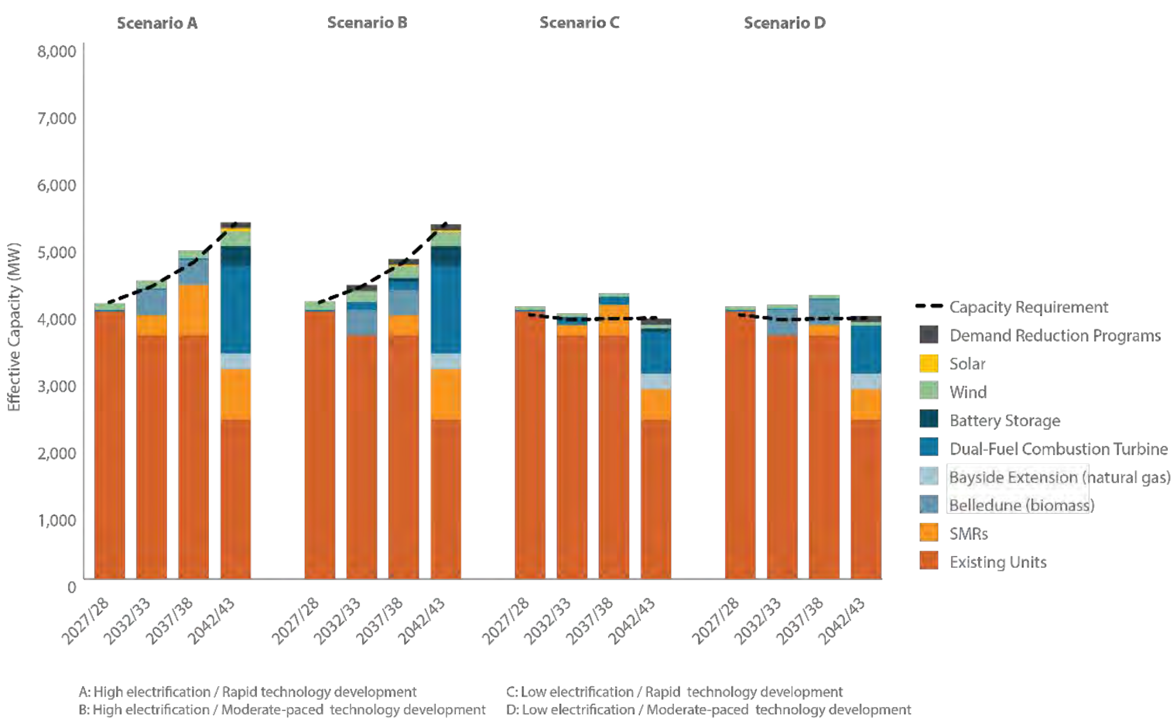
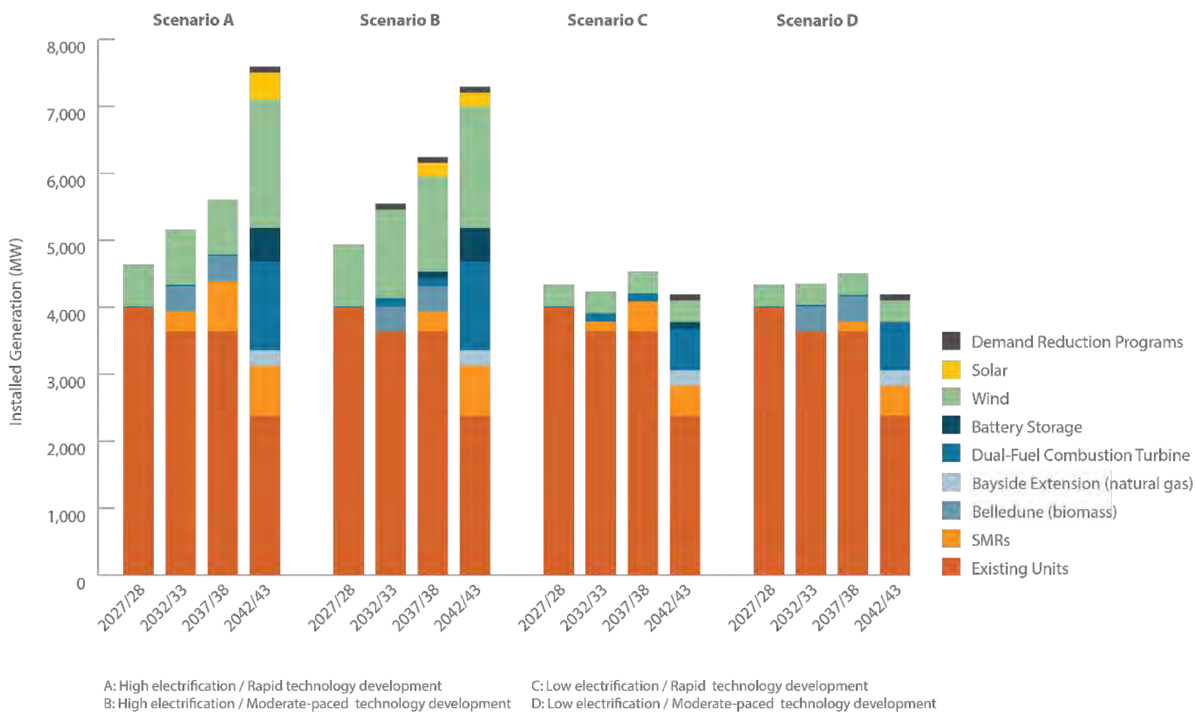


Figure 11.7: Installed (Nameplate) Generation by Scenario



At least 300 MW of wind is installed in each scenario in the early years. This is a reflection of the reduced cost for wind relative to the variable cost of fuel prices on market imports.
In the scenarios with increased electrification (A and B), there are additional wind builds, ramping up through the study period to serve the growing energy need. These two scenarios also see solar as part of the energy mix.

The wind build between the Rapid Technology development scenarios (A and C), which have lower overall wind capital costs and the moderate-paced technology development scenarios (B and D), is very low, suggesting that the rollout of new renewable resources is less sensitive to capital costs than other factors such as load requirements and meeting policy targets.

Table 11.2 contains a summary of projects that are needed in all base scenarios. These projects provide value to the system and are not sensitive to the key uncertainties identified (electrification and pace of technology development).

Table 11.2: Summary of Common Actions

Year	Installed Generation	Technology
2026/27	300 MW	Wind
2027/28 to 2032/33	668 MW	Mactaquac Life Achievement Project
2034/35	150 MW	SMRs
2038/39	230 MW	Bayside Gas Turbine Extension
2039/40	450 MW	SMRs
2040/41	600 MW	Dual Fuel Combustion Turbines
2040/41	90 MW	Demand Response

Adding 300 MW of wind provides a benefit to NB Power customers in 2026/27 across all base scenarios by reducing fuel and purchased power costs. In February 2023, NB Power issued a Request for Expressions of Interest for renewable energy projects to advance its efforts to increase its installed renewable capacity.

The Mactaquac Life Achievement project is included in all base scenarios. It provides significant value to customers, as explored in detail in Section 12.1.

The timing and volume of SMRs changes across the base scenarios, but at least 150 MW is installed by 2034/35 and 450 MW by 2039/40 across all scenarios. The role of SMRs in reaching net-zero is explored in detail in Section 12.2.

The Bayside gas turbine extension, 600 MW of dual-fuel combustion turbines and 90 MW of demand response all serve the role of providing the required capacity to replace the retiring Bayside and Coleson Cove generating stations. The ability to generate from both gaseous and liquid fuels will also keep options open for integration of renewable fuels in the future (e.g. biodiesel, renewable natural gas, hydrogen).

There are a number of other new resources that are required in some scenarios, but are not common across all. The Belledune biomass conversion is included in three of four base scenarios. It is recommended that NB Power continue to investigate the role of Belledune beyond 2030, which includes exploring additional fuel options and taking a risk-based approach on the potential conditions expected in the 2030s.

The volume of wind, solar and battery projects are sensitive to the pace of electrification with higher requirements in the high electrification scenarios. Future load forecasts will provide key signposts for the volume of electrification potential, which will in turn inform the need for additional wind, solar and battery resources.

11.3.2 Energy Balance and Emissions

The energy balance in Figure 11.8 shows the declining contribution of emitting generation over time. Particularly after 2035, the role of emitting generation is strictly limited to reliability and integrating renewables. This causes a marked decline in greenhouse gas emissions, with all scenarios hitting a 98 per cent reduction from 2005 levels. While the specifics of the CER have not been finalized at the time of drafting, this reduction in emissions is consistent with or exceeding net zero analyses completed by industry experts in recent years (e.g. Clean Power Roadmap for Atlantic Canada[63]).

[63] *Natural Resources Canada, Clean Power Standing Committee. (2022) Final Report a Clean Power Roadmap for Atlantic Canada. Retrieved from the Natural Resources Canada website, https://natural-resources.canada.ca/sites/nrcan/files/energy/images/publications/2022/A%20CLEAN%20POWER%20ROADMAP%20FOR%20ATLANTIC%20CANADA-ACC.pdf*

Figure 11.8: Energy Balance by Scenario

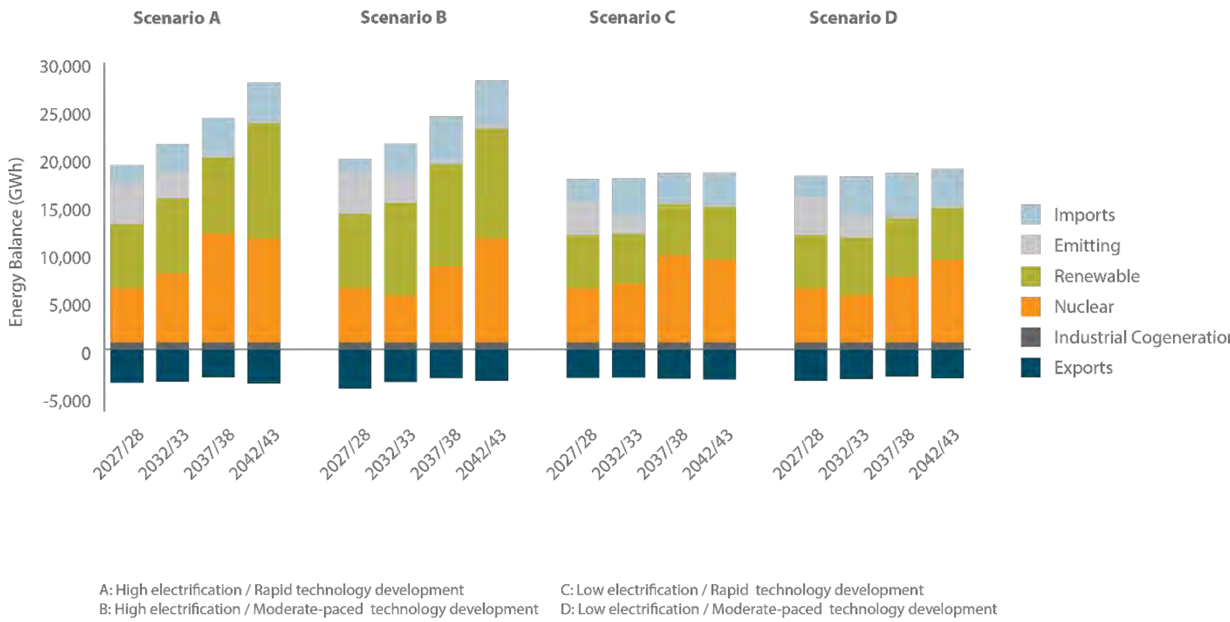
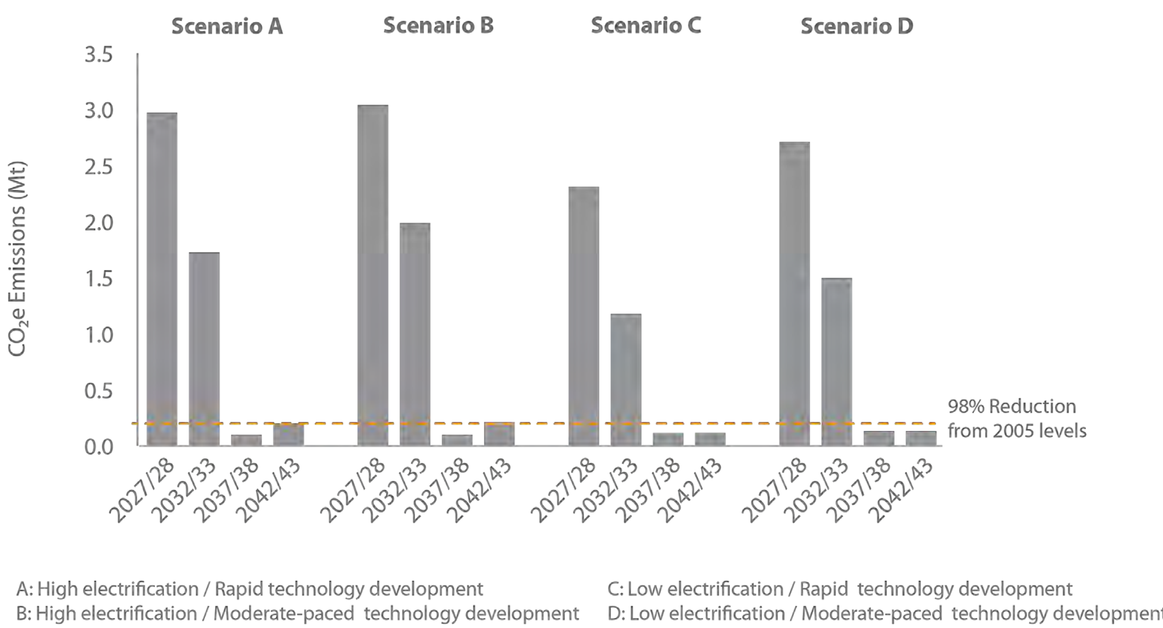


Figure 11.9: Greenhouse Gas Emissions by Scenario (CO_2e)



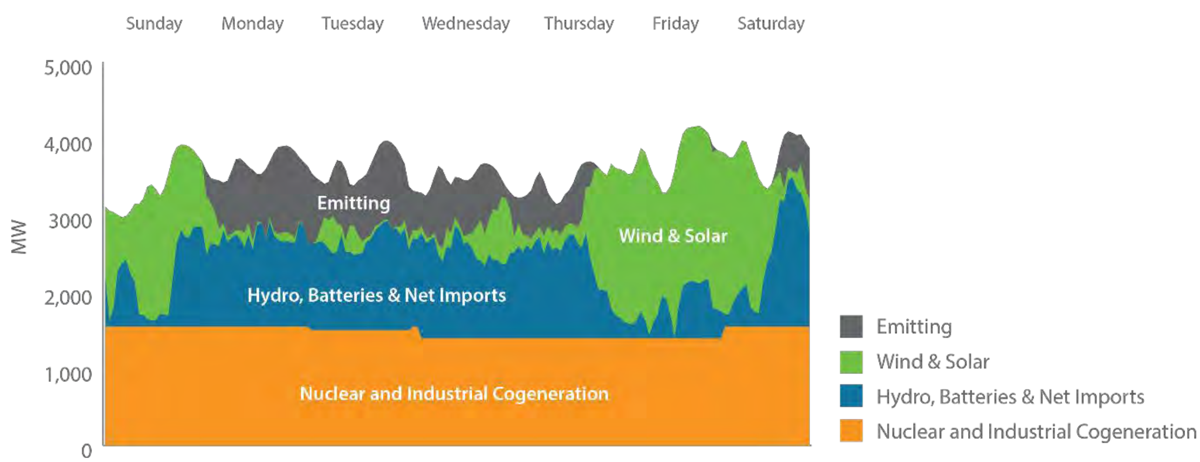
After 2035, less than 175,000 tonnes of greenhouse gas emissions remain on the grid. The remaining volume is equivalent to removing oil heat from 1,000 homes, taking 3,500 gasoline-fuelled vehicles off the road or planting 350,000 trees each year[64].

[64] *Lifetime GHG emission savings assumed at 175 tonnes per oil-heated home, 50 tonnes per gasoline vehicle and 0.5 tonnes per tree.*

11.3.3 Operational Characteristics - Hourly

A view of the hourly dispatch can also provide additional understanding of how the energy needs are being met at a finer resolution. Figure 11.10 below shows the hourly dispatch for Scenario A in a week in January 2043 of relatively low wind. Note that without the thermal generation provided, 20 to 30 per cent of customers would be without electricity for four days. The system would need an unreasonable volume of battery storage to maintain generation adequacy through this challenging period without the availability of thermal resources[65]. The role of thermal generation that can inject energy into the grid for prolonged periods to maintain reliability is paramount as society becomes increasingly dependent on electricity.

Figure 11.10: Scenario A - Hourly Energy Balance for a Week in Jan 2043



The low load periods provide a different type of challenge, with over-generation becoming an issue. Figure 11.11 shows a week in October 2042 from Scenario A, where excess generation is first exported into neighbouring jurisdictions up to its limit[66] and then required to curtail to maintain reliability. As the penetration of renewables grows, the ability to reduce output to respond to curtailment needs becomes increasingly important.

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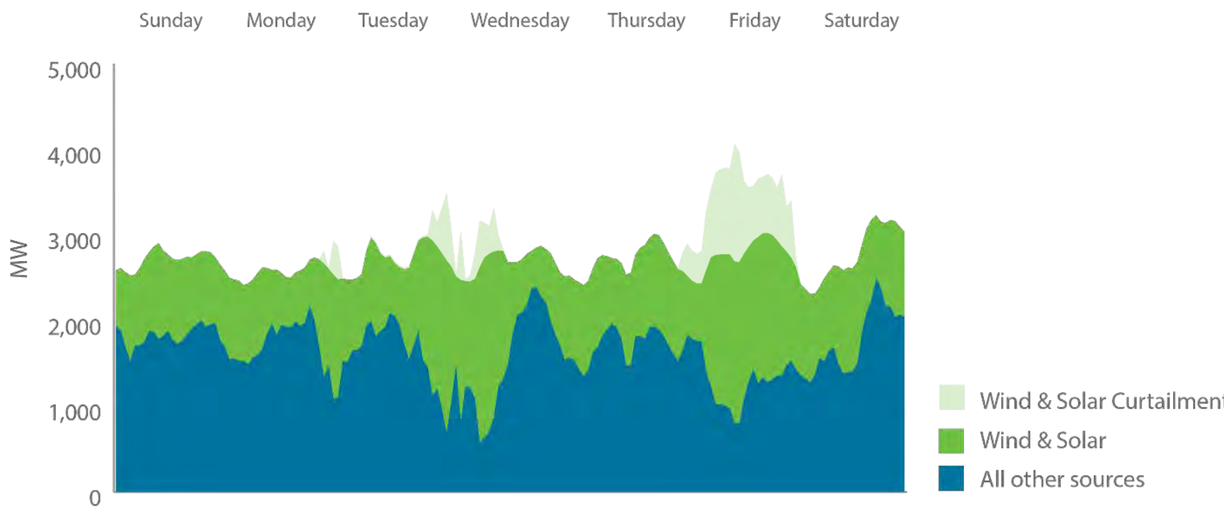
[65] *For illustrative purposes, an additional 16,000 MW of 4-hr battery storage, or over 5,000 MW of longer duration (12-hr) battery storage would be required. This would come at an approximate cost in 2042/43 of $24 billion or $20 billion respectively.*

[66] *Exports depend on neighbours' needs, current system constraints and market value. Additional variable renewable generation could limit export opportunities further than the constraints seen in today's market.*

Figure 11.11: Scenario A - Hourly Energy Balance for a Week in Oct 2042



11.3.4 Financial Impacts

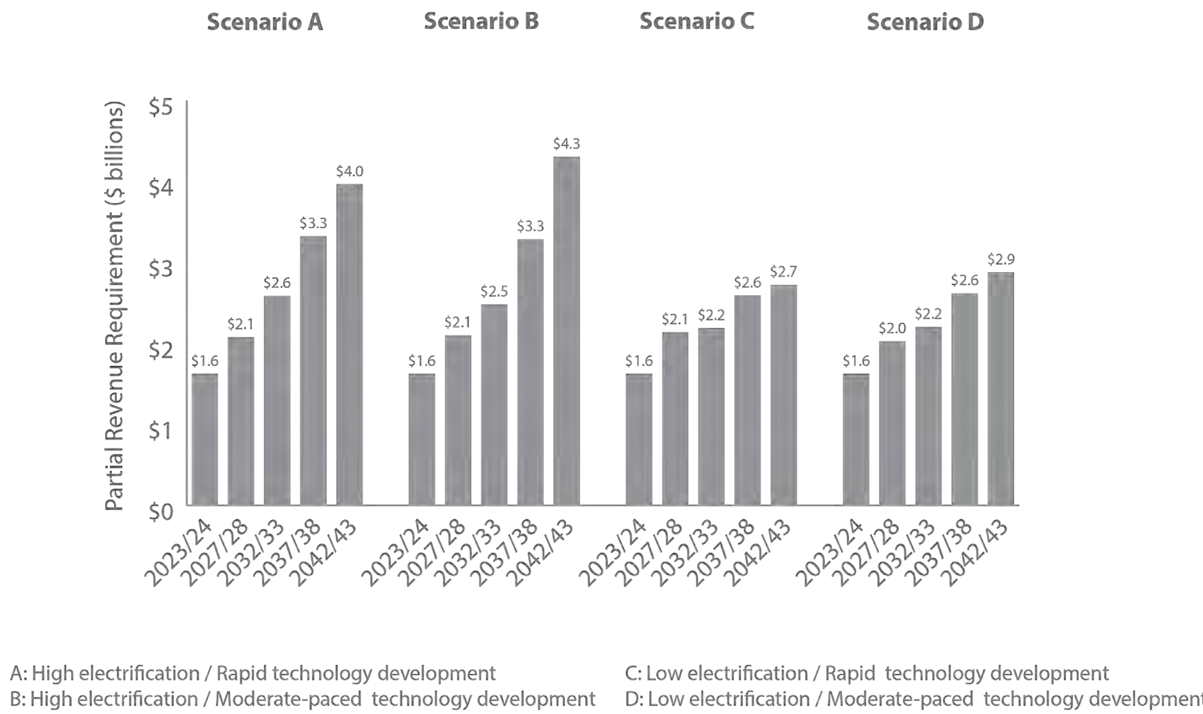
The financial standing of each base scenario is independent and not readily comparable to each other due to the differing input cost assumptions and overall energy requirements. Comparisons between scenarios are better left to the sensitivity section where the value or cost of projects can be more appropriately compared. The costs presented should instead be considered as the range of possible outcomes to be expected, dependent on how conditions unfold in future years.

Two views on costs have been prepared to help understand the impact of the scenarios and the expected policy changes that drive changes in the overall expansion plan: the annual partial revenue requirement and the annual partial revenue requirement normalized for in-province energy volumes which provides a view of the average cost to serve customers.

Partial revenue requirement (PRR) is calculated as the total revenues to be collected through rates from in-province customers[67]. This is also net of any miscellaneous or export revenues that help to offset the cost to New Brunswick customers. It is worth noting that this is different from the total revenue requirement presented in NB Power's General Rate Application to the New Brunswick Energy and Utilities Board. The PRR for each scenario is shown in Figure 11.12 below.

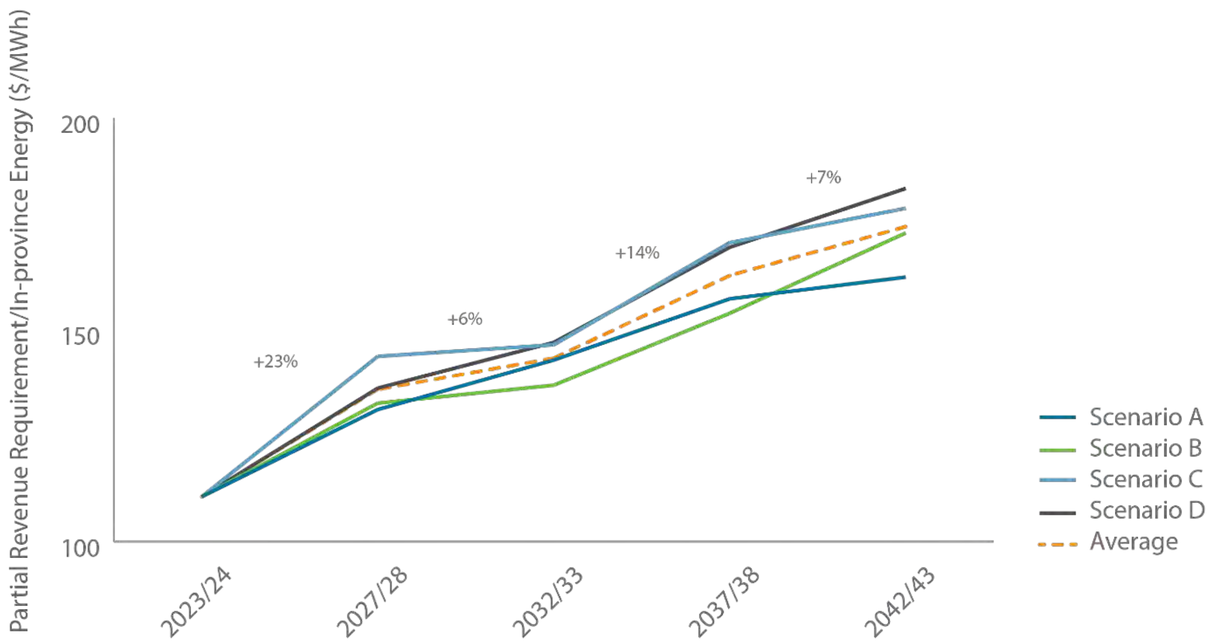
[67] *Note that significant transmission upgrades within New Brunswick will be required in some scenarios. These costs require further study and have not been included in this IRP.*

Figure 11.12: Partial Revenue Requirement by Scenario



The partial revenue requirement (PRR) is highest in Scenarios A and B, driven primarily by the higher loads to be served. The largest increases occur from 2023/24 to 2027/28 (driven by the NB Power's targeted debt to equity ratio) and 2032/33 to 2037/38 driven by the Clean Electricity Regulation. Figure 11.13 normalizes the PRR for in-province energy sales volume, showing the average cost to serve in each year.

Figure 11.13: Average Cost to Serve (PRR /In-Prov Energy Requirements) by Scenario[68]



Between 2023/24 and 2027/28, the average cost to serve (PRR/In-province energy) increases significantly across all scenarios, on average by 23 per cent in just four years. This is driven by NB Power's target to reduce debt and achieve a capital structure of at least 20 per cent equity. This puts considerable near-term upward pressure on rates. Over the next five years, the average cost to serve increases at a more modest pace. The next period sees large increases again (+14 per cent on average for the five-year period), driven by the onset of the Clean Electricity Regulation in 2035. The average cost to serve stabilizes again between 2037/38 and 2042/43, with modest increases.

Another takeaway from the analysis is that the higher electrification scenarios (A and B) overall have lower average costs to serve than their low electrification counterparts (C and D), suggesting that there are economies of scale to be gained in increasing in-province load.

12 Sensitivities

The objective of the sensitivity analysis of the IRP is to provide a view of what NB Power's pathways to a net-zero electricity system may look like and highlight the role that major projects may play in achieving that vision as well as identify key risks. Three major projects have been chosen for sensitivity analysis: the Mactaquac Life Achievement Project (MLAP), SMRs and the Atlantic Loop. The MLAP and rollout of SMRs exist in the base scenarios, so the sensitivity analysis explores the counterfactual where these projects are not pursued (Mactaquac retirement and no SMRs). The Atlantic Loop is not present in the base scenarios, so the sensitivity analysis looks at the impact of including the Atlantic Loop.

[68] *Percentage increases are shown for the average of the four scenarios and fully span the period between years. For example, the 23 per cent increase between 2023/24 and 2027/28 is equivalent to a 5.3 per cent annual average increase.*

Cost comparisons relative to the base scenarios will provide guidance toward the overall cost sensitivity of a project within the planning horizon (2023/24-2042/43), but a complete analysis of each major project is not included in Mactaquac Retirement or No SMR sensitivities. The Atlantic Loop sensitivity includes capital and operating cost estimates, though there is considerable uncertainty on the impacts of federal support or preferred financing from the Canadian Infrastructure Bank. A business case for any of these projects would need to properly account for these costs, as well as other factors (e.g. differing lifetimes of the projects), but doing so is outside of the scope of this IRP, which is more directly focused on the decarbonization story and overall pathways to net-zero.

12.1 Mactaquac Retirement Sensitivity

The Mactaquac Generating Station is a run of the river hydro facility with an installed generation capacity of 668 MW, supplying about 12 per cent of New Brunswick homes and businesses with clean, low-cost power. NB Power is proposing a project to ensure the station can operate to its intended 100-year lifespan with a modified approach to maintenance and adjusting and replacing equipment over time. This recommendation follows years of expert research, including input from scientists, engineers, the public and Indigenous communities.

The Mactaquac Life Achievement Project (MLAP) would see the station continue to operate beyond 2030, extending the life to 2068. Mactaquac is a critical piece of New Brunswick's generating infrastructure and it is important to understand the alternatives to the MLAP. This is not a recommendation to proceed with the project, rather the Mactaquac Retirement sensitivity explores the pathways to a net-zero electricity system if the MLAP were not pursued.

12.1.1 Approach and Assumptions

Mactaquac has the capacity to generate 668 MW of electricity from six turbine generator units. The facility is used for both peaking and load-following generation as well as providing ancillary services, such as automatic generation control (AGC) and synchronous condensing. Mactaquac serves a crucial role in the New Brunswick electricity system by providing spinning and non-spinning reserves for various failure scenarios required by the North American Electric Reliability Council (NERC), including fast start and black start capability. Currently, Mactaquac provides 75 per cent of NB Power's hydro generating capacity; 20 per cent of New Brunswick's peak energy needs; as well as 30 per cent of the province's renewable energy requirements. The facility provides real-time reliability and balances supply with demand hour-to-hour.

The analysis in this sensitivity relates strictly to the changes in overall balance of system for generation. It does not include the capital costs of the MLAP nor does it include any transmission related costs that would be required if the station were retired. Capacity based ancillary services such as AGC, load following and operating reserve are accounted for in the analysis while other services such as frequency response, voltage control and system black start are not considered in this IRP.

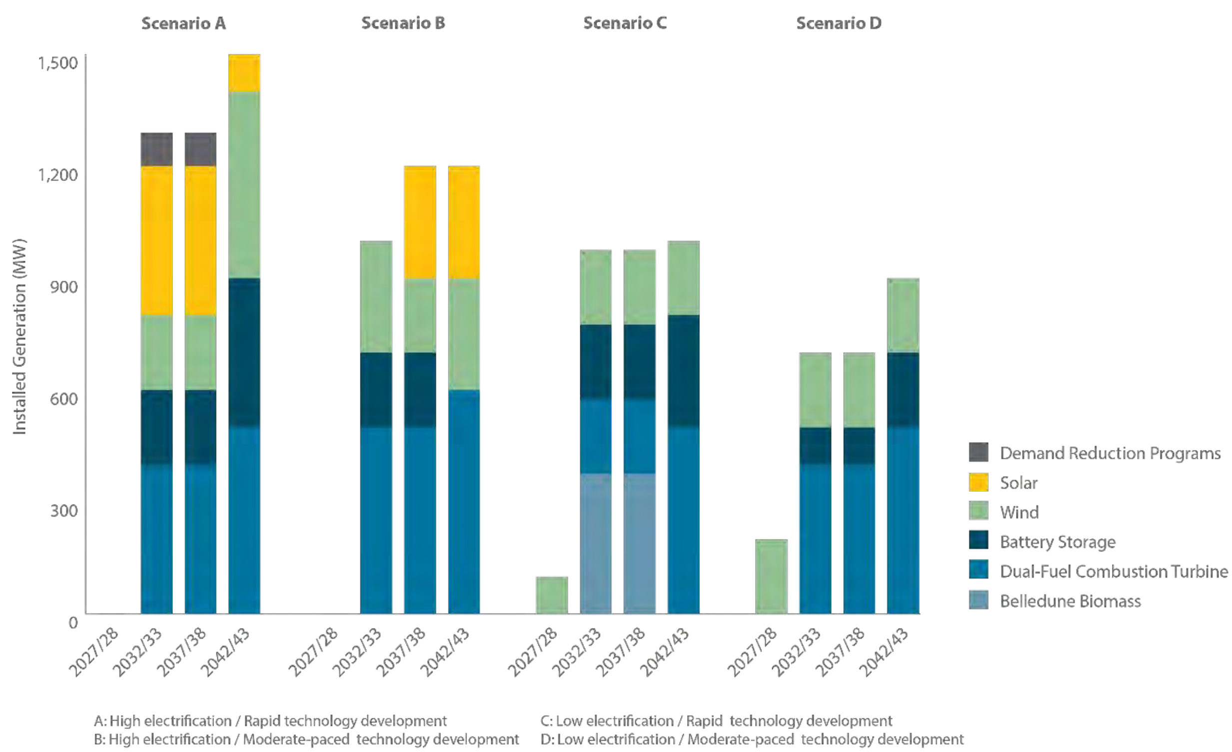
12.1.2 Results and Discussion

The replacement of Mactaquac requires three main services

- renewable energy to maintain environmental constraints such as the forthcoming Clean Electricity Regulation[69]
- capacity to meet generation adequacy minimums prescribed by the Northeast Power Coordinating Council (NPCC)
- ancillary service capability for balancing energy in real-time and maintaining required operating reserves

Figure 12.1 shows the additional resources required to replace the services of Mactaquac. Total installed capacity for the sensitivity would be the sum of the values in Figure 12.1 with those in Figure 11.7. This total is included in Appendix D.

Figure 12.1: Mactaquac Replacement Generation Capacity

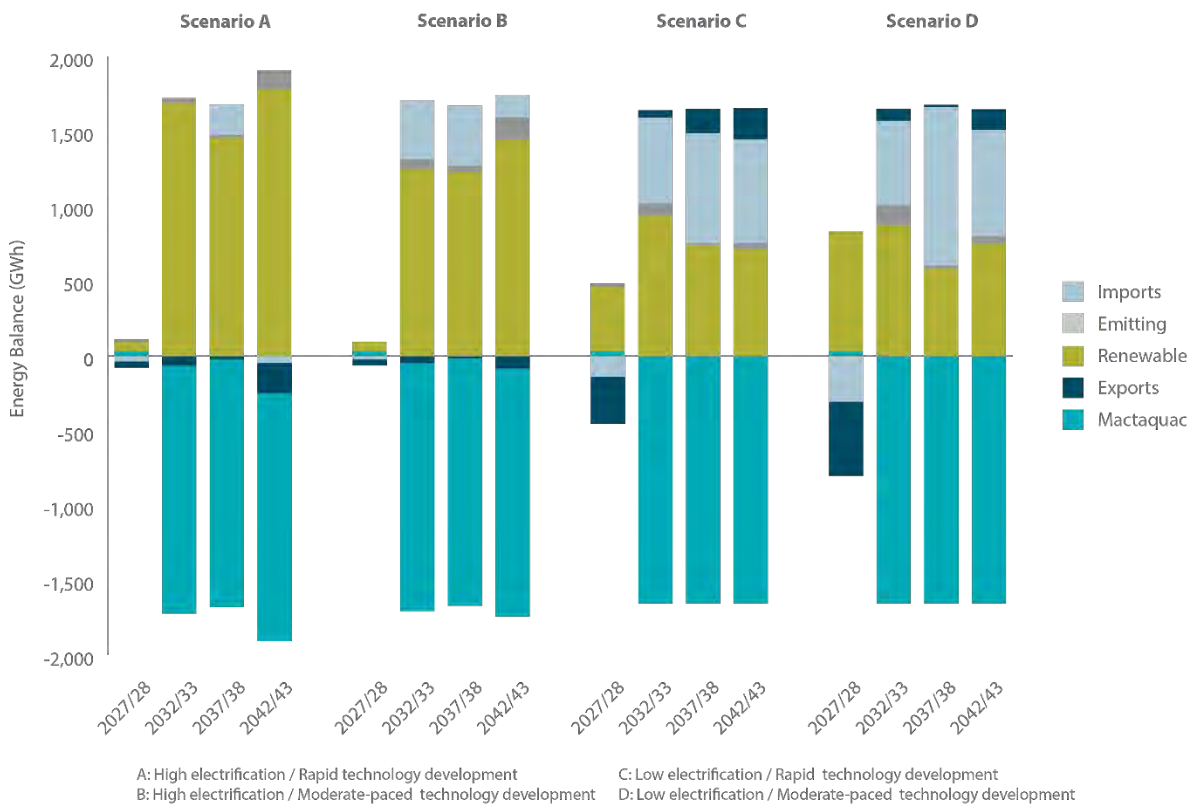


In Scenario A, the replacement capacity comes from a mix of dual-fuel CTs, battery storage and accelerating the 90 MW DR program. The replacement energy is coming from a mix of additional wind and solar. Additional batteries will help balance the variable renewable resources as well as provide ancillary services. Scenario B follows similar trends.

[69] *The expansion plans for the Mactaquac Retirement scenarios are predicated on the assumption that the Clean Electricity Regulation will be in place in 2035. If only currently active policies were considered, thermal generation would be a much larger part of the replacement energy and ancillary service provision. Greenhouse gas emissions under those scenarios would be approximately a megatonne higher than the scenarios including the Mactaquac Life Achievement Project.*

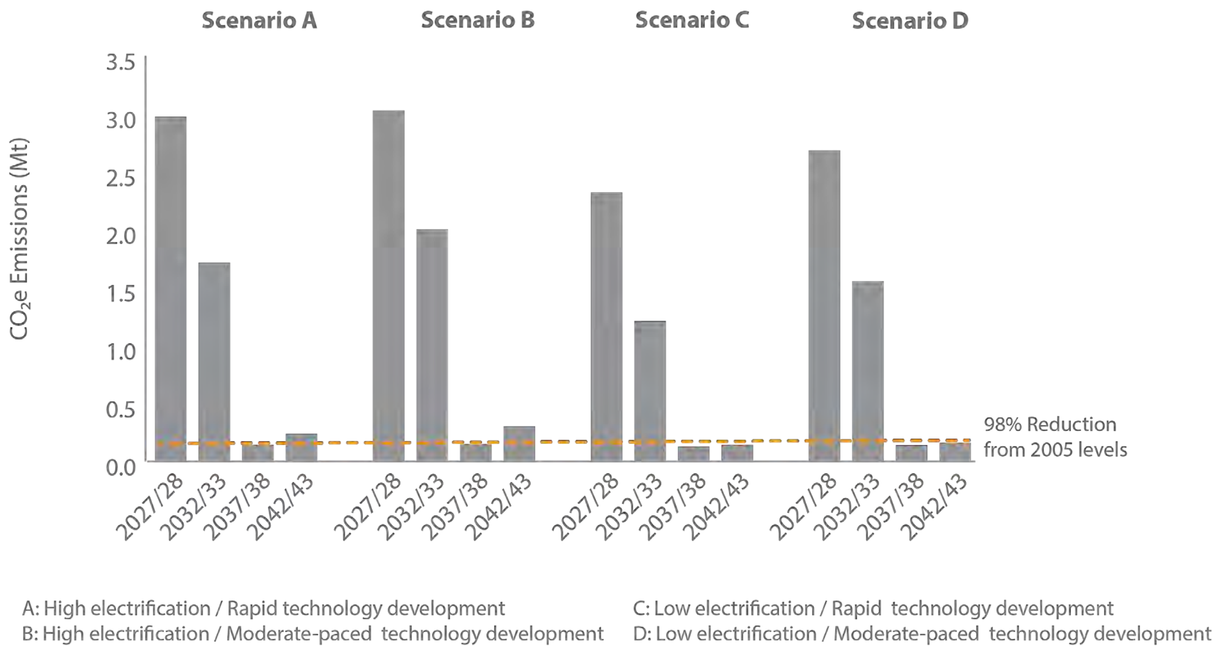
In Scenario C, in the 2030s, some of the energy and capacity is replaced by the Belledune biomass conversion[70]. At the end of the period, the capacity is provided by CTs and battery storage, with the energy replacement coming from a mix of wind generation and market purchases. Scenarios C and D build fewer in-province renewables because there is still remaining import capability due to the relatively low loads, whereas in Scenarios A and B, the import capability is at capacity more often due to the increased load from high electrification.

Figure 12.2: Mactaquac Replacement Energy



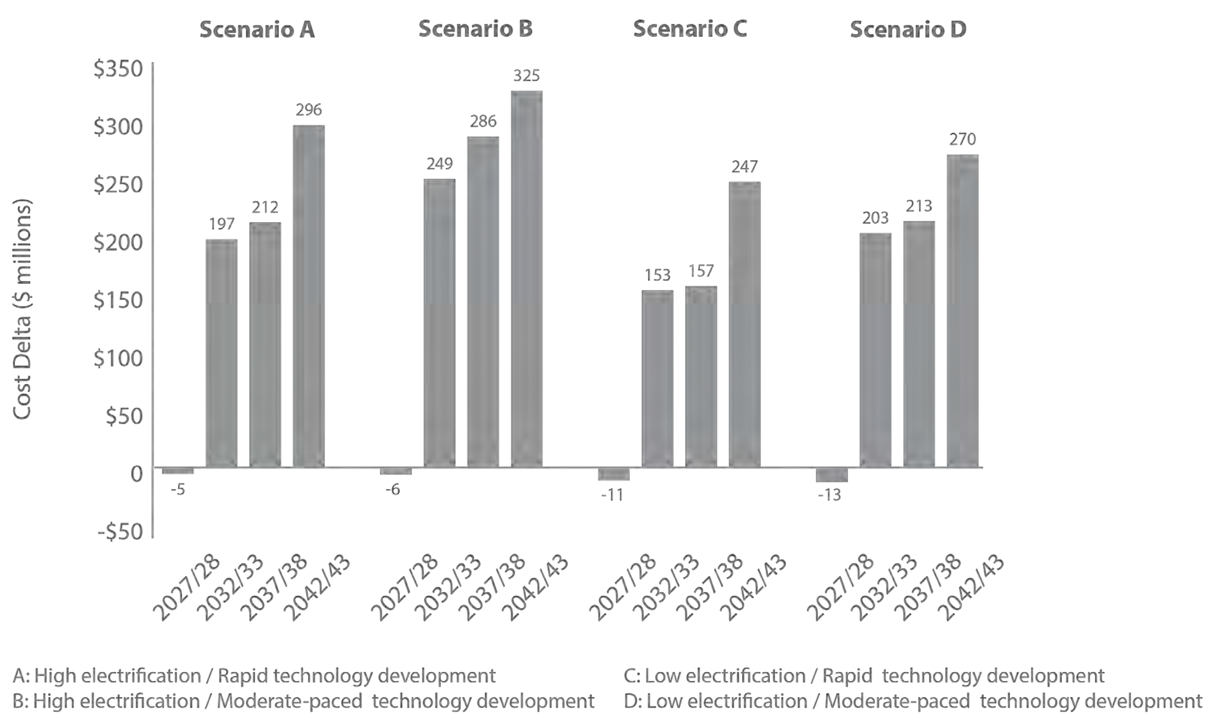
[70] *The Belledune biomass conversion option is included in the base scenarios for A, B and D. This means that it cannot be a 'replacement' for Mactaquac in those scenarios as it is already present. The Belledune Biomass conversion is selected in all Mactaquac Retirement Scenarios.*

Figure 12.3: GHG Emissions - Mactaquac Retirement Scenarios



The emissions presented in Figure 12.3 show on average, slight increases over the base scenarios but still in the range of a 98 per cent reduction from 2005 levels after 2035. The Clean Electricity Regulation (CER) necessitates drastic decreases in overall emissions, so this outcome is not unexpected.

Figure 12.4: Change in Generation Costs from the Base Scenarios (excluding MLAP costs)



The change in generation costs shown in Figure 12.4 is a measure of the value that the MLAP brings to the system by offsetting the need for additional generation resources and replacement energy. It excludes all direct MLAP costs.

A small negative is present in 2027/28 as MLAP has begun in the base scenarios, but Mactaquac Generating Station is operating at full capacity in the Mactaquac retirement scenarios. The value of MLAP increases in the other years, as new resources are required to be built in the Mactaquac retirement scenarios. The value is lowest in Scenario C due to the availability of the Belledune biomass conversion as a low-cost alternative. In 2042/43, the value for the scenarios with the Mactaquac Life Achievement Project range from $247-$325 million[71] annually. Over the period 2030-2068, the total value, including offsetting capital investments and replacement energy range, from a high of approximately $3.8 billion in scenario B to a low of $2.8 billion in scenario C ($2022 NPV). These estimates do not include transmission system upgrade costs associated with losing Mactaquac, nor some ancillary services such as black start, frequency response and voltage control.

Mactaquac Generating Station is a key pillar in the transition to a net-zero electricity system. In its absence, more variable renewables are built and without the balancing services and operating reserves provided by Mactaquac Generating Station, the costs quickly balloon. Mactaquac plays a valuable role of enabling the low-cost integration of renewables which becomes increasingly important in the future. Without Mactaquac the system would consist of large volumes of intermittent renewables, balanced by batteries, imports and low capacity-factor CTs. This type of system design is a significant departure from current operations necessitating additional studies to determine what additional transmission and distribution upgrades would be required. These studies are outside of the scope of this IRP.

12.2 No SMR Sensitivity

Advanced nuclear or small modular reactors (SMRs) represent a burgeoning industry with a high potential to lower global emissions by providing stable and reliable base-load, non-emitting electricity generation. NB Power, along with the Government of New Brunswick, have been working collaboratively to progress advanced SMR designs for commercial demonstration in New Brunswick. The *Climate Change Action Plan 2022-2027* action 7 (see Section 4.3) looks to develop a clean electricity strategy, inclusive of two first-of-a-kind SMRs to help decarbonize New Brunswick's electricity sector. It is important to understand the viability of alternatives to SMRs, so a No SMR sensitivity is included to explore this topic. This is not a recommendation to proceed with the project, rather the sensitivity explores alternative pathways to a net-zero electricity system that don't include advanced SMRs.

12.2.1 Approach and Assumptions

The No SMR sensitivity explores the pathways to a net-zero electricity system if advanced SMRs were not pursued in New Brunswick. The SMR rollouts are detailed in Section 11.2.4. The scope of this sensitivity is simply to remove these units from the plan and allow the capacity expansion model to economically choose, with consideration for all policy objectives, the replacement for these units. There is no change to the assumptions regarding Point Lepreau Nuclear Generating Station's continued operation through the period.

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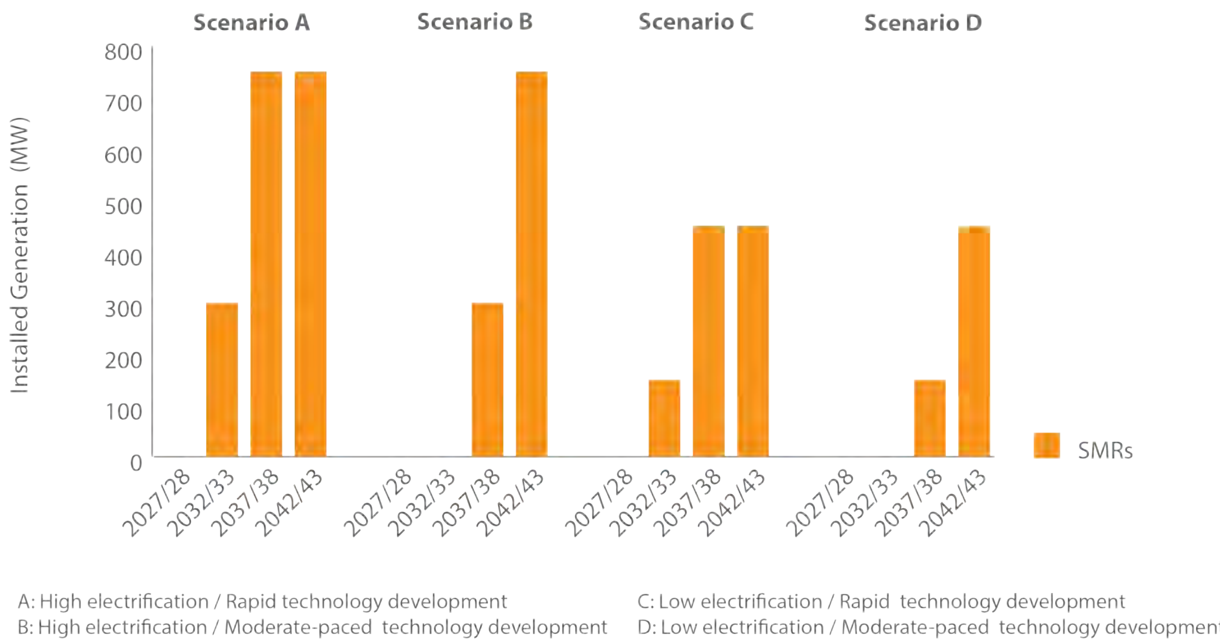
[71] Mactaquac's forecasted output is 1,657 GWh annually. Leveling this cost for energy generated results in an equivalent savings of $150-$200/MWh.

Figure 12.5: SMR Installed Generation Capacity included in Base Scenarios

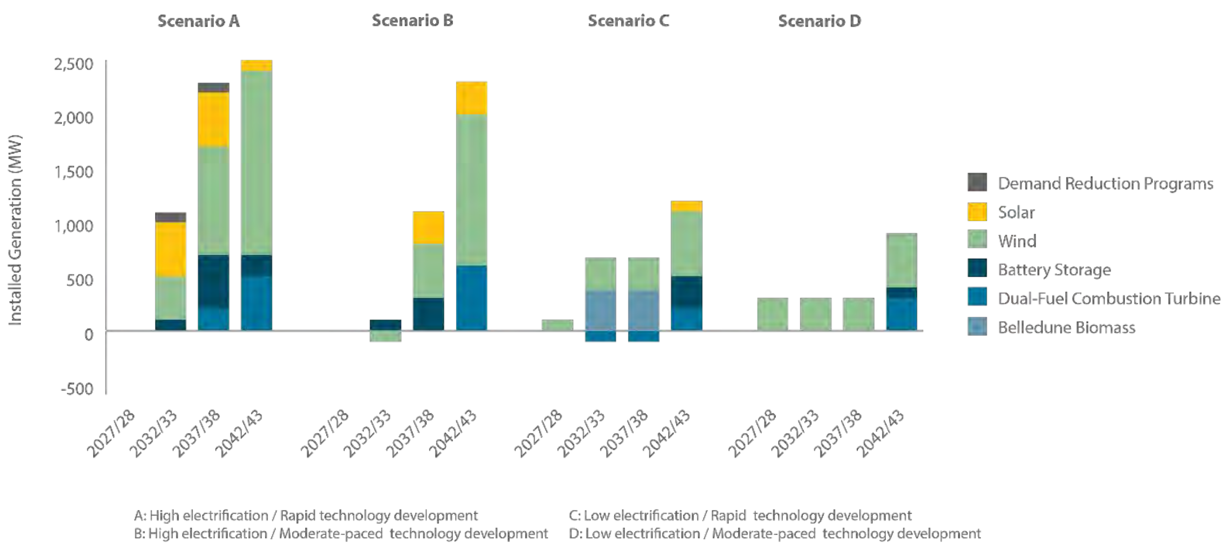


The analysis in this sensitivity relates strictly to the changes in overall balance of system costs for generation. It does not include the capital or ongoing operations costs for SMRs, nor does it include any transmission related costs that would be required. Capacity based ancillary services such as AGC, load following and operating reserve are accounted for in the analysis.

12.2.2 Results and Discussion

The role of SMRs on the electricity system is to provide baseload, carbon-free energy to the grid as well as capacity to maintain reliability. Figure 12.6 shows the additional generation sources that would be required if SMRs were not present. Total installed generation capacity for the sensitivity would be the sum of the values in Figure 12.6 with those in Figure 11.7. This total is included in Appendix D.

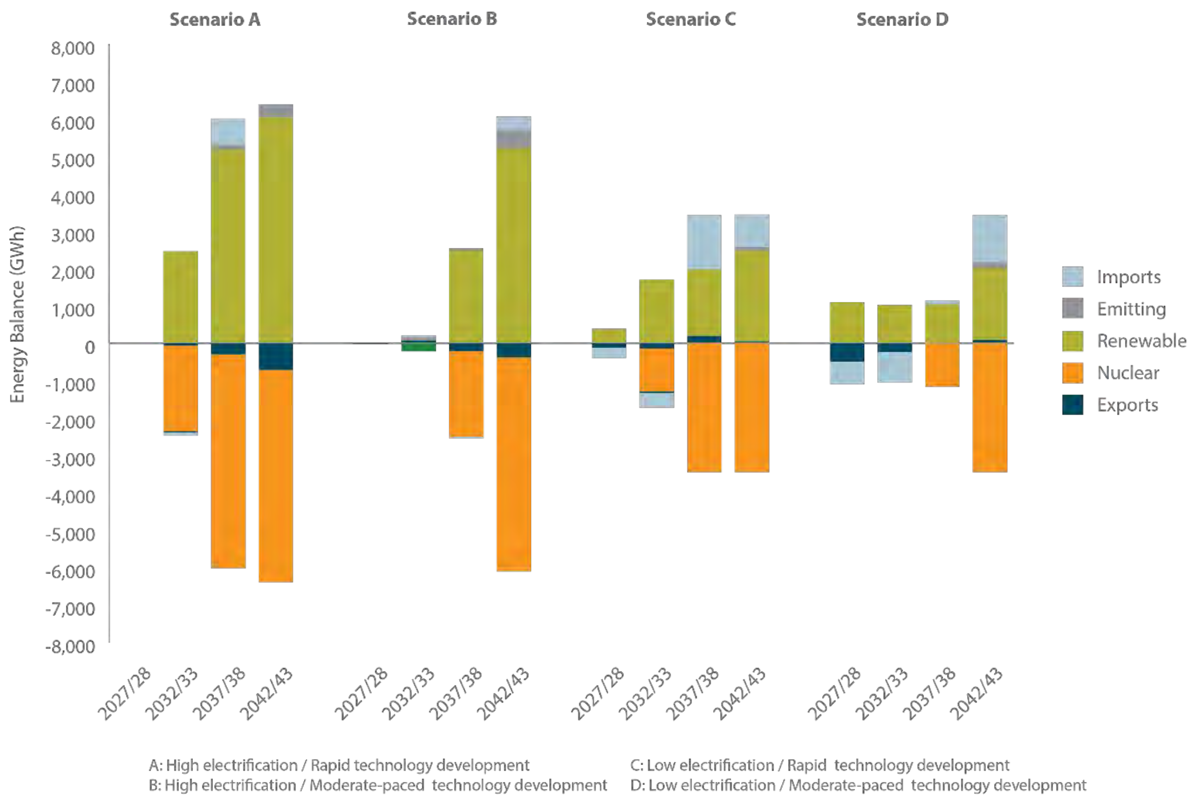
Figure 12.6: Change in Installed Capacity – No SMR Scenarios Compared to Base Scenarios



The capacity to replace SMRs is coming from a mix of dual-fuel CTs as well as new battery storage. In Scenario C, in the 2030s, the capacity needs are met by the Belledune biomass conversion[72]. Wind and solar builds help to fill in the energy gap.

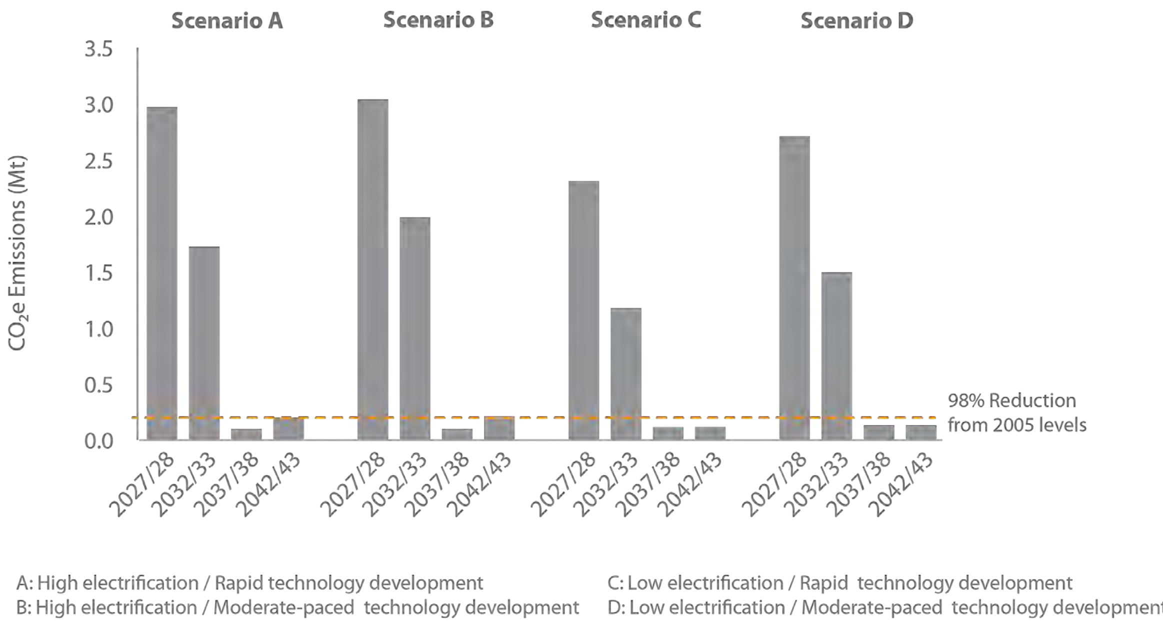
[72] *The Belledune biomass conversion option is included in the base scenarios for A, B and D. This means that it cannot be a 'replacement' for SMRs in those scenarios as it is already present. The Belledune biomass conversion is selected in all No SMR Scenarios.*

Figure 12.7: SMR Replacement Energy



The replacement energy in Scenarios C and D comes from a mix of renewables (mostly wind) and imports. In Scenarios A and B, the vast majority of the energy is sourced from renewables (mostly wind). Across all scenarios there is a small increase in emitting generation and corresponding small increase in total emissions. The majority of the years after 2035 still hit the 98 per cent reduction from 2005 level target, but a few are slightly higher.

Figure 12.8: GHG Emissions – No SMR Scenarios

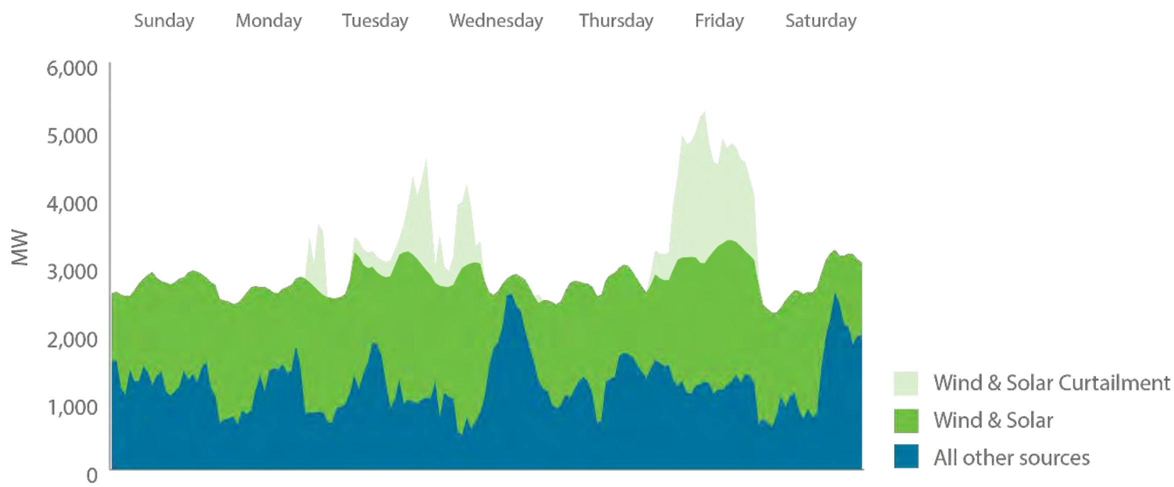


The total wind and solar build in 2042/43 to replace the energy from the 750 MW of SMRs in Scenario A is 1,900 MW of wind with 100 MW of solar and in Scenario B is 1,800 MW of wind with 300 MW of solar. This is on top of the base scenario expansion plans and current installed capacities. Overall, these two scenarios end up totaling over 3,000 MW of wind and over 500 MW of solar, a more than 10-fold increase from today's penetrations of variable renewables in New Brunswick.

This scale and scope of variable renewable penetration has not been studied in New Brunswick before. The complexities of transmission constraints, voltage and frequency control require operational studies to determine how the variability and forecast error may impact operations and reliability. This is further complicated by the reduction in other in-province generation in the no SMR sensitivity. Figure 12.9 shows the forecasted variability of wind and solar over a week in October 2042 for Scenario A with no SMRs. Contrasting this with Figure 11.11, two items stand out. First, the variability of the 'other resources' has increased significantly while the overall volume of energy from these sources has declined. This means that the balance of the system will require more flexibility while operating at lower generation levels.

Second, the volume of curtailments has increased up to 2,200 MW in some hours. This highlights the need for control and the curtailability to be built into future wind and solar power purchase agreements.

Figure 12.9: Hourly Generation for a Week in October 2042 – Scenario A, No SMR Sensitivity



In the absence of SMRs, additional variable renewables are integrated into the system. The scale and scope of variable renewables built in Scenarios A and B is unlike any system plan ever put forward by NB Power[73]. At these high penetrations curtailment becomes the norm, completely altering the dynamics of daily operations, creating significant risk until more detailed operational studies can be completed.

The costs of SMRs are another significant unknown. Until more certainty on all of these issues is obtained, a full cost-benefit analysis cannot be completed and therefore is not in this analysis. Despite this, SMRs play a critical role in New Brunswick's pathways to net-zero. Particularly, with increased load from electrification, SMRs provide a stable, predictable generation source in a future where that is becoming increasingly less common. It is recommended that NB Power and the Government of New Brunswick continue to work together to progress SMR development including pursuing the required system studies needed to fully understand the costs and benefits to New Brunswickers.

12.3 Atlantic Loop Sensitivity

The Atlantic Loop is a transmission infrastructure project that would increase the import capability for renewable electricity from Québec into the Maritimes. The project would consist of a 1,150 MW of high voltage, direct current (HVDC) transmission line from Manicougan, Québec to a HVDC terminal in Salisbury, NB. Additional alternating current (AC) transmission lines would be constructed to carry the energy through New Brunswick into Nova Scotia.

[73] *For comparison, the penetration of variable renewables contemplated in the 2020 IRP was an additional 278 MW of wind.*

Figure 12.10: The Proposed Atlantic Loop Project would Increases Electricity Import Capability into the Maritimes[74]

The Atlantic Loop has garnered national attention for its potential to enable the phase-out of coal-fired electricity in Nova Scotia and New Brunswick. The new transmission infrastructure would reinforce currently limited pathways and alleviate bottlenecks in existing infrastructure, notably in the southeast of New Brunswick.

While the benefits of the project are numerous, the capital investment alone is estimated at approximately $6 billion, creating a significant hurdle to overcome to provide value to New Brunswickers. The project is predicated on the availability of renewable energy in Québec over-and-above existing import volumes.

12.3.1 Approach and Assumptions

The Atlantic Loop sensitivity explores the pathways to a net-zero electricity system that are enabled by additional transmission projects to import renewable energy from outside the province. This is not a decision document on this topic nor a recommendation to proceed with any projects, simply an exploration into the pathways to net zero with the Atlantic Loop in their future.

The Atlantic Loop brings an additional 1,150 MW of transmission capacity between Québec and New Brunswick into service in 2030 as well as strengthens the interface with Nova Scotia. For this sensitivity, it was assumed that half of the transmission capacity was prioritized for each of New Brunswick and Nova Scotia. Any flows or transactions over the Nova Scotia portion are assumed to continue through New Brunswick into Nova Scotia and are outside the scope of this analysis.

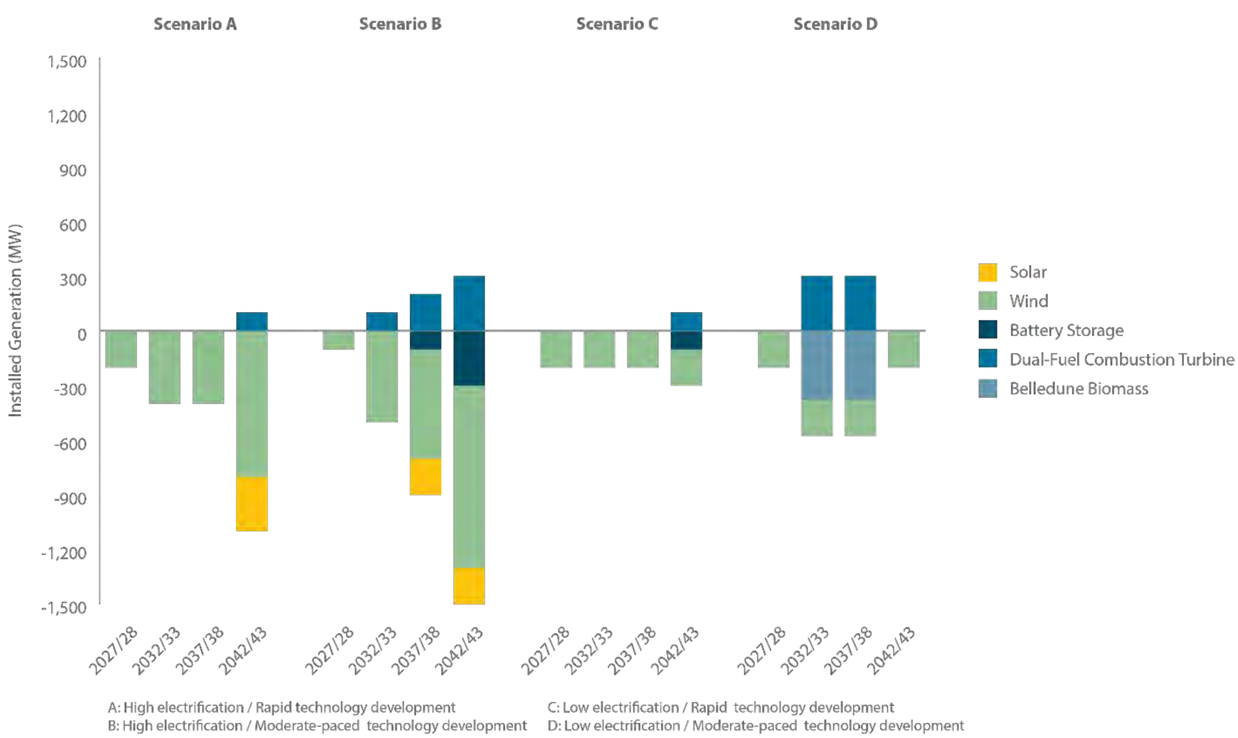
[74] *Natural Resources Canada, Clean Power Standing Committee. (2022) Final Report a Clean Power Roadmap for Atlantic Canada. Retrieved from the Natural Resources Canada website, https://natural-resources.canada.ca/sites/nrcan/files/energy/images/publications/2022/A%20CLEAN%20POWER%20ROADMAP%20FOR%20ATLANTIC%20CANADA-ACC.pdf*

The New Brunswick portion was assumed at 575 MW and modelled as a purchased power agreement with a minimum utilization factor of 50 per cent in each year. The price for energy purchased was aligned to a comparable import price from the New England electricity market. While energy has been assumed to be available from Québec, firm capacity has not been included in the assumed power purchase agreement structure. This is consistent with assumptions around the long-term procurement of capacity from other jurisdictions which are not considered practical or consistent with energy security requirement due to all of NB Power's neighbours expecting significant load growth especially in the winter, the time when NB also needs capacity the most.

12.3.2 Results and Discussion

The increased import capability is shown in Figure 12.11, but because the imports are assumed to be non-firm[75], there is no corresponding reduction in firm capacity resources needed in New Brunswick. There are declines in renewable energy builds, as the Atlantic Loop helps fill in the energy requirements. Batteries, which were helping balance the large volumes of variable renewables are also dropped in favour of dual-fuel CTs. CTs pair well with the Atlantic Loop, as the imports are scheduled hourly and therefore don't require batteries for balancing and the CTs provide energy security in the case of a forced outage on the transmission system that would limit the import capability. In Scenario D, the Belledune biomass conversion is replaced by a combination of the Atlantic Loop and CTs in the 2030s.

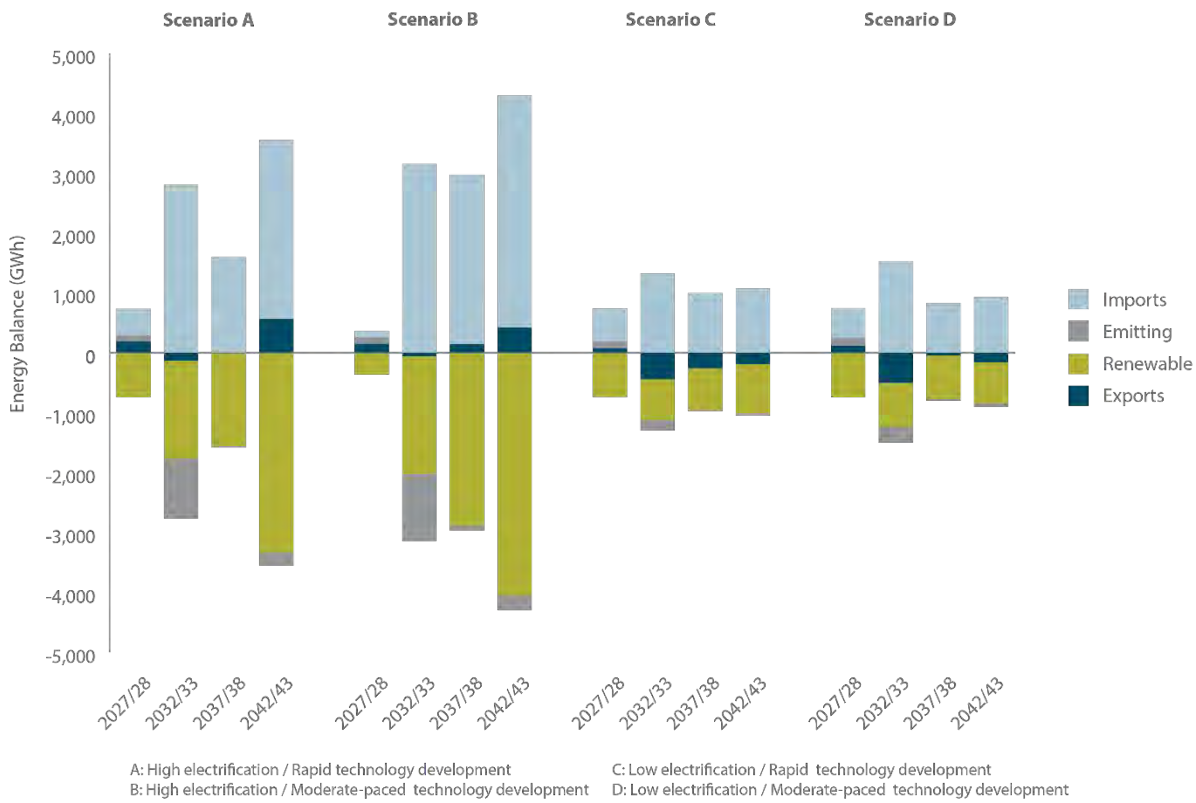
Figure 12.11: Change in Installed Capacity – Atlantic loop Scenarios Compared to Base Scenarios



The energy balance shows that in Scenario C and D, the Atlantic Loop cannibalizes imports across existing infrastructure leading to only a small net increase in imports of approximately 1,000 GWh. Therefore, only a small volume of other renewable energy is offset by the increase in imports. Increases to exports mean that in some hours, the minimum volume from the Atlantic Loop is being exported rather than consumed in-province.

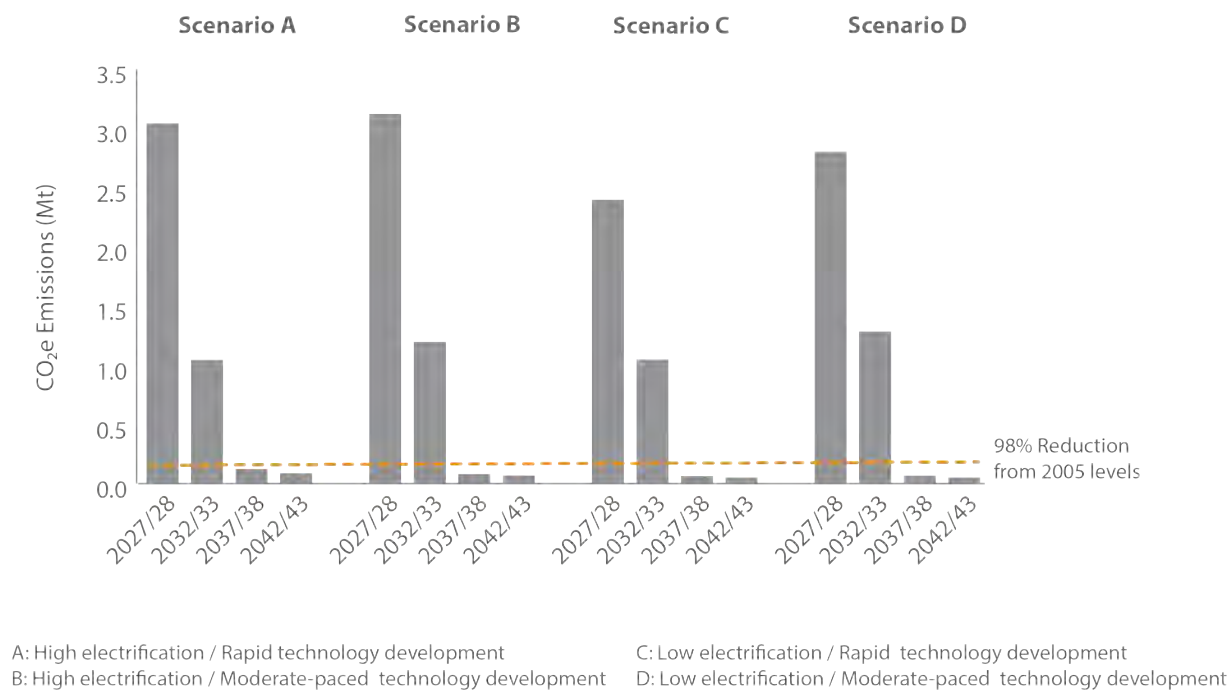
[75] *Non-firm imports are not backed by firm capacity resources in their jurisdiction of origination, meaning that they are subject to curtailment during periods of high loads. Therefore they do not contribute toward effective (firm) capacity.*

Figure 12.12: Energy Balance - Atlantic loop Scenarios Compared to Base Scenarios



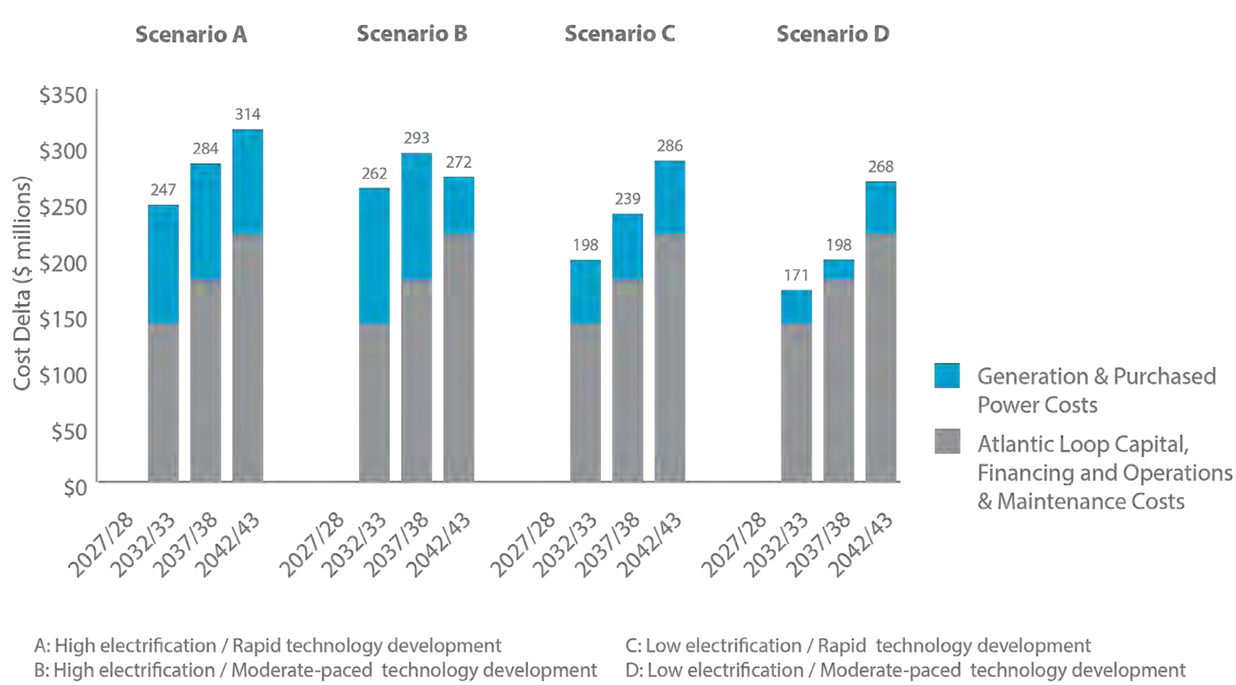
In Scenarios A and B, increases to imports are higher, especially in the 2042/43 year. The increase in imports corresponds to decreases in renewable generation (wind and solar in this instance). There is also a reduction in emitting generation after 2035 in this scenario, as the amount of CT generation required to provide energy security to the Atlantic Loop is considerably less than what is needed to integrate variable renewables while maintaining reliability.

Figure 12.13: GHG Emissions – Atlantic Loop Scenarios



All Atlantic Loop scenarios more than achieve the 98 per cent reduction from 2005 levels target after 2035. The Atlantic Loop scenarios have lower emissions than the base scenarios in the early 2030s. The energy in that period helps offset generation from Coleson Cove and Bayside generating stations, leading to GHG reductions.

Figure 12.14: Increased Costs in Atlantic Loop Scenarios from Base Scenarios (excludes Utility Tax Impacts)



Generation costs (inclusive of import costs) increase in the scenarios with the Atlantic Loop. This is driven by two factors: the price of the energy (assumed at competitive market prices) and the minimum volume (2,500 GWh per year). This results in many hours when there is a lower cost alternative available, but the minimum volume requirement forces the system to import from the Atlantic Loop despite the higher cost.

This highlights one of the key challenges or barriers to the Atlantic Loop project. The hours when the Atlantic Loop can provide value to New Brunswick are limited. This challenge relates to the existing import capability in New Brunswick of over 1,200 MW. A 575 MW increase to import capability has a diminishing value as the Atlantic Loop is only providing value in hours when the existing infrastructure is being fully utilized.

The capital, financing and operations and maintenance costs of the Atlantic Loop are large, exceeding $100 million in each year after the project comes into service. This creates a significant barrier to overcome in order to make the project a least-cost solution for New Brunswickers. There would need to be a larger savings on the side of generation and purchased power costs to make the project viable, but we see the opposite happening, with increases to these costs under the Atlantic Loop scenarios. These factors combine to put the project at a $220-$270 million per year disadvantage in the early 2040s relative to the base scenarios that instead build new carbon-free resources in New Brunswick.

The Atlantic Loop could aid in New Brunswick's path to net-zero, but it faces significant cost barriers. A 2,500 GWh per year power purchase agreement with Québec alone results in an increased cost over the alternative and excludes the billions of dollars of investment required for the project to come to fruition. The current view is that the least cost alternative for New Brunswick is to build carbon-free resources in the province. NB Power continues to explore the opportunity to better understand the costs and advantages of the Atlantic Loop. The value is very dependent on the structure of any power purchase agreements, which remains an area of considerable uncertainty.

13 Conclusion

The IRP provides strategic insight and analysis to guide NB Power when planning its future resource needs.

A summary follows of the conclusions taken from the analysis.

- Public Engagement findings indicate
    - the top two priorities for customers and stakeholders are limiting price increases and focusing on reliability
    - environmental concerns and carbon emission reductions are very important to Indigenous people and New Brunswickers
    - the desire of Indigenous communities to be involved in owning and partnering on future projects presents NB Power with an opportunity to build on reconciliation and develop positive relationships with Indigenous communities in New Brunswick. Partnerships on future generation projects can have positive financial benefits for all parties.

- NB Power's goals of achieving and maintaining a capital structure of 20 per cent equity will be challenged by the need to invest in clean electricity. Partnerships will be critical to future investment in the province.

- Provincial GHG emissions are on a downward trend due to the combination of carbon pricing, coal-phase-out and the Clean Electricity Regulation (CER)
    - The NB OBPS (carbon pricing) puts continuous pressure on emissions through to 2035, creating consistent reductions through time in all scenarios.
    - The phase-out of coal at Belledune Generating Station creates a step change reduction in provincial emissions. Converting the plant to biomass or retiring it both result in significant reductions to GHG emissions.
    - After 2035, emissions achieve a 98 per cent reduction from 2005 levels across all base scenarios. Adding the Atlantic Loop will further reduce emissions, but the gains are nominal. Removing Mactaquac or SMRs will increase emissions, but again the impacts are small as the CER is effective in limiting emissions.

- The CER's impact on emissions comes at a cost. In the base scenarios, costs increase an average of 14 per cent from 2032/33 to 2037/38 (before transmission and distribution investments).

- Emitting thermal units continue to operate at low volumes after 2035. Provisions in the CER for the continued operation of these facilities is critical to maintaining reliability and managing the cost of the clean transition.
    - The ability to generate from both gaseous and liquid fuels will also keep options open for integration of renewable fuels in the future (e.g. biodiesel, renewable natural gas, hydrogen).

- As the penetration on renewables such as wind and solar grows, the ability to dispatch these resources becomes increasingly important to maintaining reliability.

Table 13.1: Summary of Common Actions

Year	Installed Generation	Technology
2026/27	300 MW	Wind
2027/28 to 2032/33	668 MW	Mactaquac Life Achievement Project
2034/35	150 MW	SMRs
2038/39	230 MW	Bayside Gas Turbine Extension
2039/40	450 MW[76]	SMRs
2040/41	600 MW	Dual Fuel Combustion Turbines
2040/41	90 MW	Demand Response

- Wind generation provides value across all base scenarios with at least 300 MW of installed capacity added by 2027/28.

- The Bayside Gas Turbine (GT) Extension is an excellent alternative to retirement. It is selected across all plans and is the lowest cost of capacity of all options examined.

- The Mactaquac Life Achievement Project has tremendous value in the NB electricity system by providing clean electricity, capacity and low-cost, carbon-free generation that can provide ancillary services. Mactaquac's flexibility also enables the low-cost integration of renewables, which becomes increasingly important in the future.
    - A sensitivity analysis that retired Mactaquac in 2030 identified much higher generation and purchased power costs totalling $2.8-$3.8 billion ($2022 NPV) over the life of the project[77].

[76] *Includes the 150 MW of SMRs built in earlier years.*
[77] *Excluding the capital and other operation costs for the Mactaquac Life Achievement Project.*

- SMRs are a critical part of the future of electricity in New Brunswick. They provide a unique opportunity for New Brunswick to offer stable and predictable carbon-free generation.
    - A sensitivity analysis that removed SMRs identified extreme volumes of wind and solar builds (over 4,000 MW) for some scenarios, which are orders of magnitude higher than any wind integration study completed to-date.

- The Belledune biomass conversion is selected in many scenarios. It is sensitive to the amount of electrification in the province as well as the presence of other major projects. In all 'High Electrification' scenarios as well as all scenarios where MLAP or SMRs are not present, the project provides value to customers.
    - The future of Belledune Generating Station is subject to the key areas of uncertainty identified in the IRP. It is recommended that NB Power continue to investigate the role of the Station beyond 2030, including exploring additional fuel options and take a risk-based approach on the potential conditions expected in the 2030s.

- A sensitivity that included increased transmission import capacity via the Atlantic Loop identified that it can help enable decarbonization, but its economic value is challenged.
    - The combination of infrastructure cost plus increased generation and purchased power costs would raise costs to New Brunswick electricity customers by $270-$310 million per year in the 2040s, an approximate seven to nine per cent increase in costs in those years over the scenarios without the Atlantic Loop.
    - A lower cost solution is to build carbon-free resources in New Brunswick.

- The build-out of new wind and other renewables requires more system integration, operational and transmission studies. In some scenarios, installed capacities approach 10 times the current installed capacity in New Brunswick, highlighting the issues of system reliability and energy security that will require further study should changes in the landscape suggest we are moving in the direction of one scenario over another. The addition of this much new wind and other renewables will require significant investment in transmission and distribution infrastructure, for which costs have not been quantified in the IRP as it is uncertain where these potential resources would ultimately choose to interconnect.

The plan provides a view of numerous pathways toward a net-zero electricity system. The general take-away is that there is no one solution. Achieving net-zero will require new carbon-free generation projects such as MLAP, SMRs, Belledune biomass conversion, new wind, new solar and new battery storage projects.

Appendix A – Key Assumptions

<table>
<tr><th>Category</th><th>2023 Integrated Resource Plan Assumption</th></tr>
<tr><td>Belledune</td><td>Coal as a fuel does not continue beyond December 31, 2029.
Biomass fuel available in 2030, operation limited to November to March due to fuel volume limitations and fuel costs.</td></tr>
<tr><td>Mactaquac</td><td>Life Achievement project goes from 2027 – 2032.
Capacity losses during MLAP are replaced through contract purchases from neighbouring utilities.</td></tr>
<tr><td>SMRs</td><td>Two first of kind SMRs added in all scenarios as part of NB Climate Change Action Plan.
Roll out varied by timing and volume based on scenario
High Electrification / Rapid Tech – 750 MW 2029/30-2034/35
High Electrification / Moderate Tech – 750 MW 2034/35-2040/41
Low Electrification / Rapid Tech – 450 MW 2029/30-2034/35
Low Electrification / Moderate Tech – 450 MW 2034/35-2040/41</td></tr>
<tr><td>Greenhouse Gas Regulations</td><td>Based on the New Brunswick Output-Based Pricing System for large emitters until 2035.
Price ramping from $65/tonne in 2024 to $170/tonne in 2030 and beyond.
Based on Clean Electricity Regulations discussion paper
All emissions taxed beginning 2035.
Fossil fuel generators allowed for renewable integration and reliability. Generation limited to 5 per cent capacity factor per year.
Responsibly sourced Biomass considered non-emitting.</td></tr>
<tr><td>Mandated Capital Structure</td><td>A capital structure of at least 20 per cent equity is achieved by 2026/27.</td></tr>
<tr><td>Economic Assumptions</td><td>CPI for fiscal year 2022/23 is 7 per cent dropping to 2.9 per cent in 2023/24 and gradually dropping to 2.0 per cent per year starting in fiscal 2026/27. Forecast sourced from the Conference Board of Canada (CBOC) data published on October 31, 2022.
Long term foreign exchange rate of $1.30 (USD/CAN) based on Conference Board of Canada Quarterly Rates Data/Forecast Published October 2022.
Long term debt financing rate of 4.99 per cent based on an analysis of public financing rates (3.37 per cent long term bond rate, 97 basis point spread and provincial guarantee fee of 0.65 per cent).
Return on Equity for public owned projects assumed to be 10.00 per cent. Privately financed assumed 11 per cent.
Weighted average cost of capital of 5.99 per cent based on the long-term capital structure target, long term debt financing rate and return on equity assumptions.</td></tr>
<tr><td>Fuel and Electricity Market Price Forecast</td><td>Short term fuel and electricity market prices based on the 2023/24 NB Power Budget.
Long term fuel and electricity market price forecasts provided by Energy Ventures Analysis Inc.</td></tr>
</table>

Category	2023 Integrated Resource Plan Assumption
In Province Load Forecast	• Low electrification scenario based on the NB Power Load Forecast 2022-2032 completed in 2022. • High electrification scenario includes accelerated EV rollout and 1,000 MW of additional industrial load by 2042/43.
Export Load	• Firm export contracts are assumed to be maintained. • Other opportunity exports are modelled or estimated based upon margins currently generated from existing export load and changes in plant availability in the future.
Capacity Planning Reserve Criteria	• Minimum reserve of 20 per cent as per the 2022 Maritimes Area Comprehensive Review of Resource Adequacy published by the Northeast Power Coordinating Council.
Generation Resources	• Existing generating stations operate until their planned retirement dates. • Hydro generating stations are assumed to be refurbished or replaced in-kind upon retirement. • Point Lepreau Nuclear Generating Station's retirement date is extended outside the period covered by the IRP based on projected operating hours. • Renewable PPAs are assumed to be extended, at market value if the underlying resources are technically capable of reliably generating electricity.
Supply Side Resources	• Supply side options and costs provided by Energy and Environmental Economics and NB Power data. • Screening analysis based on emission profiles, dispatch characteristics and cost effectiveness.
Demand Response	• 90 MWs of effective capacity taking 7 years to ramp up to full value assumed available starting in 2030. • 90 MWs is made up of rate programs, water heater load shifting and commercial and industrial demand response programs.
Energy Efficiency	• In all scenarios, efficiency programs achieve legislated annual energy savings targets. o Targets ramp from 0.5 per cent of sales in 2023/24 to 0.75 per cent of sales in 2028/29 and all years thereafter.

Appendix B – Load Forecast Tables

Forecasted Energy after Demand Side Management Savings (GWh)

Year	Scenario A	Scenario B	Scenario C	Scenario D
2023/24	14,622	14,622	14,622	14,622
2024/25	14,934	14,935	14,934	14,935
2025/26	15,019	15,021	14,914	14,917
2026/27	15,454	15,457	14,922	14,926
2027/28	15,834	15,839	14,872	14,877
2028/29	16,279	16,286	14,892	14,900
2029/30	16,712	16,723	14,896	14,908
2030/31	17,187	17,204	14,937	14,954
2031/32	17,635	17,661	14,931	14,957
2032/33	18,103	18,141	14,945	14,983
2033/34	18,923	18,980	15,269	15,326
2034/35	19,439	19,524	15,256	15,342
2035/36	19,994	20,121	15,239	15,366
2036/37	20,543	20,722	15,226	15,406
2037/38	21,121	21,353	15,214	15,446
2038/39	21,722	22,006	15,208	15,492
2039/40	22,363	22,699	15,198	15,535
2040/41	22,989	23,378	15,190	15,579
2041/42	23,681	24,122	15,192	15,633
2042/43	24,402	24,896	15,196	15,690

Forecasted Demand Side Management Savings (GWh)

Year	Scenario A	Scenario B	Scenario C	Scenario D
2023/24	63	63	63	63
2024/25	151	151	151	151
2025/26	248	248	248	248
2026/27	355	355	355	355
2027/28	496	496	496	496
2028/29	613	613	602	602
2029/30	732	732	708	708
2030/31	855	855	814	814
2031/32	981	981	920	920
2032/33	1,110	1,111	1,026	1,026
2033/34	1,245	1,246	1,135	1,136
2034/35	1,384	1,386	1,244	1,245
2035/36	1,527	1,529	1,353	1,355
2036/37	1,674	1,677	1,462	1,465
2037/38	1,824	1,830	1,571	1,576
2038/39	1,980	1,987	1,679	1,686
2039/40	2,139	2,149	1,788	1,797
2040/41	2,304	2,316	1,896	1,908
2041/42	2,473	2,489	2,005	2,020
2042/43	2,647	2,666	2,113	2,132

Forecasted Demand after Demand Side Management Savings (MW)

Year	Scenario A	Scenario B	Scenario C	Scenario D
2023/24	3,094	3,094	3,094	3,094
2024/25	3,110	3,110	3,110	3,110
2025/26	3,147	3,147	3,099	3,099
2026/27	3,184	3,184	3,087	3,087
2027/28	3,230	3,230	3,076	3,076
2028/29	3,267	3,268	3,061	3,062
2029/30	3,300	3,301	3,046	3,051
2030/31	3,330	3,330	3,038	3,038
2031/32	3,398	3,399	3,025	3,026
2032/33	3,425	3,425	3,013	3,013
2033/34	3,495	3,503	3,024	3,035
2034/35	3,569	3,569	3,024	3,032
2035/36	3,633	3,635	3,021	3,028
2036/37	3,672	3,694	3,026	3,028
2037/38	3,726	3,726	3,026	3,029
2038/39	3,849	3,849	3,030	3,030
2039/40	3,890	3,899	3,018	3,030
2040/41	3,963	3,963	3,024	3,031
2041/42	4,124	4,124	3,032	3,033
2042/43	4,208	4,208	3,032	3,037

Forecasted Demand Side Management Savings (MW)

Year	Scenario A	Scenario B	Scenario C	Scenario D
2023/24	18	18	18	18
2024/25	36	36	36	36
2025/26	56	56	56	56
2026/27	78	78	78	78
2027/28	100	100	100	100
2028/29	126	126	123	123
2029/30	154	154	147	147
2030/31	182	182	171	171
2031/32	210	211	195	195
2032/33	240	240	218	218
2033/34	271	271	243	243
2034/35	303	303	268	268
2035/36	335	336	293	293
2036/37	369	370	318	318
2037/38	403	404	342	344
2038/39	439	440	367	369
2039/40	475	477	392	394
2040/41	513	515	417	420
2041/42	551	555	442	445
2042/43	591	595	466	471

Appendix C – Project and Operating Cost Parameters

Technology	Installed Capacity (MW)	Capacity Factor (%)	In-Service Cost ($/kW)	Expected Life (Years)	Heat Rate (MMBtu/MWh)	CO2 Intensity (t/GWh)	LCOE - Capital ($/MWh)	LCOE - Fuel ($/MWh)	LCOE - VO&M ($/MWh)	LCOE - FO&M ($/MWh)	LCOE - CO2 Cost ($/MWh)	LCOE - Total ($/MWh)	LCOC - Total ($/kW-month)
Solar - Utility Scale	50	19	1,969	30	0	0	65	0	0	15	0	80	111
Solar - Residential Rooftop	0.004	19	4,059	25	0	0	149	0	0	15	0	164	228
On-shore Wind	30	41	2,089	30	0	0	32	0	0	15	0	47	93
Off-shore Wind	400	45	5,399	30	0	0	75	0	0	26	0	102	222
Wave	1	26	18,599	30	0	0	450	0	0	254	0	704	267
Tidal	10	26	14,267	30	0	0	345	0	0	157	0	502	191
New Biomass Boiler	60	90	6,556	20	13,500	0	58	203	7	26	0	294	59
Geothermal	1	90	11,437	25	0	0	89	0	0	23	0	111	77
Gas – Combined Cycle Gas Turbine	500	75	2,101	25	6,410	340	20	51	2	4	42	118	13
Combustion Turbine – Dual Fuel	150	5	1,472	25	9,460	502	205	114	2	37	61	418	9
Combustion Turbine - Gas	150	5	1,267	25	9,460	502	176	114	1	36	61	389	8
Gas – Combined Cycle Gas Turbine with Carbon Capture Sequestration	500	75	4,366	25	7,124	19	41	57	9	6	2	115	27
Combustion turbine – Hydrogen	150	5	3,732	25	9,730	0	520	304	14	72	0	909	23
Lithium-ion Battery (1-hour)	1	4	646	20	1,000	0	123	96	0	29	0	248	19
Lithium-ion Battery (4-hour)	1	17	1,861	20	1,000	0	89	96	0	7	0	193	20
Lithium-ion Battery (12-hour)	1	43	5,100	20	1,000	0	96	96	0	3	0	195	38
Flow Battery	1	35	4,058	20	1,000	0	93	117	0	6	0	216	32
Belledune Biomass Conversion	375	33	67	11	10,000	0	3	151	0	26	0	179	7
Bayside Gas Turbine Extension	230	5	0	15	10,370	550	0	120	0	70	63	253	3

Appendix D – Expansion Plan Tables

Base Case Scenario A: High Electrification / Rapid-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	600	-	-
2028/29	-	-	-	-	-	700	-	-
2029/30	150	375	-	-	-	800	-	-
2030/31	150	375	-	-	-	800	-	-
2031/32	300	375	-	-	-	800	-	-
2032/33	300	375	-	-	-	800	-	-
2033/34	450	375	-	-	-	800	-	-
2034/35	750	375	-	-	-	800	-	-
2035/36	750	375	-	-	-	800	-	-
2036/37	750	375	-	-	-	800	-	-
2037/38	750	375	-	-	-	800	-	-
2038/39	750	375	230	-	-	900	100	-
2039/40	750	375	230	-	100	1,000	100	-
2040/41	750	-	230	1,000	500	1,500	400	90
2041/42	750	-	230	1,200	500	1,700	400	90
2042/43	750	-	230	1,300	500	1,900	400	90

Base Case Scenario B: High Electrification / Moderate-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	900	-	-
2028/29	-	-	-	-	-	1,000	-	-
2029/30	-	375	-	100	-	1,100	-	-
2030/31	-	375	-	100	-	1,200	-	-
2031/32	-	375	-	100	-	1,200	-	90
2032/33	-	375	-	100	-	1,300	-	90
2033/34	-	375	-	100	100	1,300	100	90
2034/35	150	375	-	100	100	1,400	200	90
2035/36	150	375	-	100	100	1,400	200	90
2036/37	300	375	-	100	100	1,400	200	90
2037/38	300	375	-	100	100	1,400	200	90
2038/39	450	375	230	100	100	1,400	200	90
2039/40	750	375	230	100	100	1,400	200	90
2040/41	750	-	230	1,100	400	1,700	200	90
2041/42	750	-	230	1,200	400	1,700	200	90
2042/43	750	-	230	1,300	500	1,800	200	90

Base Case Scenario C: Low Electrification / Rapid-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	300	-	-
2027/28	-	-	-	-	-	300	-	-
2028/29	-	-	-	-	-	300	-	-
2029/30	150	-	-	100	-	300	-	-
2030/31	150	-	-	100	-	300	-	-
2031/32	150	-	-	100	-	300	-	
2032/33	150	-	-	100	-	300	-	
2033/34	150	-	-	100	-	300	-	
2034/35	450	-	-	100	-	300	-	
2035/36	450	-	-	100	-	300	-	
2036/37	450	-	-	100	-	300	-	
2037/38	450	-	-	100	-	300	-	
2038/39	450	-	230	100	-	300	-	
2039/40	450	-	230	100	-	300	-	
2040/41	450	-	230	600	100	300	-	90
2041/42	450	-	230	600	100	300	-	90
2042/43	450	-	230	600	100	300	-	90

Base Case Scenario D: Low Electrification / Moderate-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	300	-	-
2027/28	-	-	-	-	-	300	-	-
2028/29	-	-	-	-	-	300	-	-
2029/30	-	375	-	-	-	300	-	-
2030/31	-	375	-	-	-	300	-	-
2031/32	-	375	-	-	-	300	-	-
2032/33	-	375	-	-	-	300	-	-
2033/34	-	375	-	-	-	300	-	-
2034/35	150	375	-	-	-	300	-	-
2035/36	150	375	-	-	-	300	-	-
2036/37	150	375	-	-	-	300	-	-
2037/38	150	375	-	-	-	300	-	-
2038/39	150	375	230	-	-	300	-	-
2039/40	450	375	230	-	-	300	-	-
2040/41	450	-	230	700	-	300	-	90
2041/42	450	-	230	700	-	300	-	90
2042/43	450	-	230	700	-	300	-	90

Mactaquac Retirement Scenario A: High Electrification / Rapid-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	600	-	-
2028/29	-	-	-	-	-	600	-	-
2029/30	150	375	-	400	200	1,000	400	-
2030/31	150	375	-	400	200	1,000	400	90
2031/32	300	375	-	400	200	1,000	400	90
2032/33	300	375	-	400	200	1,000	400	90
2033/34	450	375	-	400	200	1,000	400	90
2034/35	750	375	-	400	200	1,000	400	90
2035/36	750	375	-	400	200	1,000	400	90
2036/37	750	375	-	400	200	1,000	400	90
2037/38	750	375	-	400	200	1,000	400	90
2038/39	750	375	230	400	400	1,200	400	90
2039/40	750	375	230	400	500	1,200	400	90
2040/41	750	-	230	1,600	800	2,000	500	90
2041/42	750	-	230	1,800	900	2,000	500	90
2042/43	750	-	230	1,800	900	2,400	500	90

Mactaquac Retirement Scenario B: High Electrification / Moderate-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	900	-	-
2028/29	-	-	-	-	-	1,000	-	-
2029/30	-	375	-	600	200	1,200	-	-
2030/31	-	375	-	600	200	1,400	-	-
2031/32	-	375	-	600	200	1,500	-	90
2032/33	-	375	-	600	200	1,600	-	90
2033/34	-	375	-	600	300	1,600	400	90
2034/35	150	375	-	600	300	1,600	400	90
2035/36	150	375	-	600	300	1,600	500	90
2036/37	300	375	-	600	300	1,600	500	90
2037/38	300	375	-	600	300	1,600	500	90
2038/39	450	375	230	600	300	1,600	500	90
2039/40	750	375	230	600	300	1,600	500	90
2040/41	750	-	230	1,600	500	1,900	500	90
2041/42	750	-	230	1,800	500	1,900	500	90
2042/43	750	-	230	1,900	500	2,100	500	90

Mactaquac Retirement Scenario C: Low Electrification / Rapid-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	400	-	-
2027/28	-	-	-	-	-	400	-	-
2028/29	-	-	-	-	-	400	-	-
2029/30	150	375	-	300	200	500	-	-
2030/31	150	375	-	300	200	500	-	-
2031/32	150	375	-	300	200	500	-	-
2032/33	150	375	-	300	200	500	-	-
2033/34	150	375	-	300	200	500	-	-
2034/35	450	375	-	300	200	500	-	-
2035/36	450	375	-	300	200	500	-	-
2036/37	450	375	-	300	200	500	-	-
2037/38	450	375	-	300	200	500	-	-
2038/39	450	375	230	300	200	500	-	-
2039/40	450	375	230	300	200	500	-	-
2040/41	450	-	230	1,100	400	500	-	90
2041/42	450	-	230	1,100	400	500	-	90
2042/43	450	-	230	1,100	400	500	-	90

Mactaquac Retirement Scenario D: Low Electrification/ Moderate-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	500	-	-
2028/29	-	-	-	-	-	500	-	-
2029/30	-	375	-	400	100	500	-	-
2030/31	-	375	-	400	100	500	-	-
2031/32	-	375	-	400	100	500	-	-
2032/33	-	375	-	400	100	500	-	-
2033/34	-	375	-	400	100	500	-	-
2034/35	150	375	-	400	100	500	-	-
2035/36	150	375	-	400	100	500	-	-
2036/37	150	375	-	400	100	500	-	-
2037/38	150	375	-	400	100	500	-	-
2038/39	150	375	230	400	100	500	-	-
2039/40	450	375	230	400	100	500	-	-
2040/41	450	-	230	1,200	200	500	-	90
2041/42	450	-	230	1,200	200	500	-	90
2042/43	450	-	230	1,200	200	500	-	90

Atlantic Loop Scenario A: High Electrification / Rapid-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	400	-	-
2027/28	-	-	-	-	-	400	-	-
2028/29	-	-	-	-	-	400	-	-
2029/30	150	375	-	-	-	400	-	-
2030/31	150	375	-	-	-	400	-	-
2031/32	300	375	-	-	-	400	-	-
2032/33	300	375	-	-	-	400	-	-
2033/34	450	375	-	-	-	400	-	-
2034/35	750	375	-	-	-	400	-	-
2035/36	750	375	-	-	-	400	-	-
2036/37	750	375	-	-	-	400	-	-
2037/38	750	375	-	-	-	400	-	-
2038/39	750	375	230	-	-	500	-	-
2039/40	750	375	230	-	100	500	-	-
2040/41	750	-	230	1,100	500	900	100	90
2041/42	750	-	230	1,300	500	1,000	100	90
2042/43	750	-	230	1,400	500	1,100	100	90

Atlantic Loop Scenario B: High Electrification / Moderate-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	800	-	-
2028/29	-	-	-	-	-	800	-	-
2029/30	-	375	-	100	-	800	-	-
2030/31	-	375	-	100	-	800	-	90
2031/32	-	375	-	100	-	800	-	90
2032/33	-	375	-	200	-	800	-	90
2033/34	-	375	-	300	-	800	-	90
2034/35	150	375	-	300	-	800	-	90
2035/36	150	375	-	300	-	800	-	90
2036/37	300	375	-	300	-	800	-	90
2037/38	300	375	-	300	-	800	-	90
2038/39	450	375	230	300	-	800	-	90
2039/40	750	375	230	300	-	800	-	90
2040/41	750	-	230	1,400	100	800	-	90
2041/42	750	-	230	1,600	200	800	-	90
2042/43	750	-	230	1,600	200	800	-	90

Atlantic Loop Scenario C: Low Electrification / Rapid-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	100	-	-
2027/28	-	-	-	-	-	100	-	-
2028/29	-	-	-	-	-	100	-	-
2029/30	150	-	-	100	-	100	-	-
2030/31	150	-	-	100	-	100	-	-
2031/32	150	-	-	100	-	100	-	-
2032/33	150	-	-	100	-	100	-	-
2033/34	150	-	-	100	-	100	-	-
2034/35	450	-	-	100	-	100	-	-
2035/36	450	-	-	100	-	100	-	-
2036/37	450	-	-	100	-	100	-	-
2037/38	450	-	-	100	-	100	-	-
2038/39	450	-	230	100	-	100	-	-
2039/40	450	-	230	100	-	100	-	-
2040/41	450	-	230	700	-	100	-	90
2041/42	450	-	230	700	-	100	-	90
2042/43	450	-	230	700	-	100	-	90

Atlantic Loop Scenario D: Low Electrification / Moderate-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	100	-	-
2027/28	-	-	-	-	-	100	-	-
2028/29	-	-	-	-	-	100	-	-
2029/30	-	-	-	300	-	100	-	-
2030/31	-	-	-	300	-	100	-	-
2031/32	-	-	-	300	-	100	-	-
2032/33	-	-	-	300	-	100	-	-
2033/34	-	-	-	300	-	100	-	-
2034/35	150	-	-	300	-	100	-	-
2035/36	150	-	-	300	-	100	-	-
2036/37	150	-	-	300	-	100	-	-
2037/38	150	-	-	300	-	100	-	-
2038/39	150	-	230	300	-	100	-	-
2039/40	450	-	230	300	-	100	-	-
2040/41	450	-	230	700	-	100	-	90
2041/42	450	-	230	700	-	100	-	90
2042/43	450	-	230	700	-	100	-	90

No SMR Scenario A: High Electrification / Rapid-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	600	-	-
2028/29	-	-	-	-	-	700	-	-
2029/30	-	375	-	-	-	1,000	400	-
2030/31	-	375	-	-	-	1,100	500	90
2031/32	-	375	-	-	-	1,200	500	90
2032/33	-	375	-	-	100	1,200	500	90
2033/34	-	375	-	-	200	1,400	500	90
2034/35	-	375	-	-	300	1,600	600	90
2035/36	-	375	-	100	400	1,700	700	90
2036/37	-	375	-	100	500	1,700	700	90
2037/38	-	375	-	200	500	1,800	700	90
2038/39	-	375	230	300	600	2,100	800	90
2039/40	-	375	230	300	600	2,100	800	90
2040/41	-	-	230	1,600	600	3,200	800	90
2041/42	-	-	230	1,800	600	3,200	800	90
2042/43	-	-	230	1,800	700	3,600	800	90

No SMR Scenario B: High Electrification / Moderate-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	900	-	-
2028/29	-	-	-	-	-	1,000	-	-
2029/30	-	375	-	-	100	1,100	-	-
2030/31	-	375	-	-	100	1,200	-	90
2031/32	-	375	-	-	100	1,200	-	90
2032/33	-	375	-	100	100	1,200	-	90
2033/34	-	375	-	100	100	1,400	100	90
2034/35	-	375	-	100	100	1,700	500	90
2035/36	-	375	-	100	400	1,700	500	90
2036/37	-	375	-	100	400	1,900	500	90
2037/38	-	375	-	100	400	1,900	500	90
2038/39	-	375	230	200	500	2,300	500	90
2039/40	-	375	230	300	500	2,300	500	90
2040/41	-	-	230	1,600	500	3,100	500	90
2041/42	-	-	230	1,800	500	3,100	500	90
2042/43	-	-	230	1,900	500	3,200	500	90

No SMR Scenario C: Low Electrification / Rapid-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	400	-	-
2027/28	-	-	-	-	-	400	-	-
2028/29	-	-	-	-	-	400	-	-
2029/30	-	375	-	-	-	600	-	-
2030/31	-	375	-	-	-	600	-	-
2031/32	-	375	-	-	-	600	-	-
2032/33	-	375	-	-	-	600	-	-
2033/34	-	375	-	-	-	600	-	-
2034/35	-	375	-	-	-	600	-	-
2035/36	-	375	-	-	-	600	-	-
2036/37	-	375	-	-	-	600	-	-
2037/38	-	375	-	-	-	600	-	-
2038/39	-	375	230	-	-	600	-	-
2039/40	-	375	230	-	-	600	-	-
2040/41	-	-	230	800	400	900	100	90
2041/42	-	-	230	800	400	900	100	90
2042/43	-	-	230	800	400	900	100	90

No SMR Scenario D: Low Electrification / Moderate-paced Technology Development (Installed Capacity Unit: MW)

	SMRs	Belledune Biomass	Bayside Extension	Dual Fuel Combustion Turbine	Battery Storage	Wind	Solar	Demand Response Programs
2023/24	-	-	-	-	-	-	-	-
2024/25	-	-	-	-	-	-	-	-
2025/26	-	-	-	-	-	-	-	-
2026/27	-	-	-	-	-	500	-	-
2027/28	-	-	-	-	-	600	-	-
2028/29	-	-	-	-	-	600	-	-
2029/30	-	375	-	-	-	600	-	-
2030/31	-	375	-	-	-	600	-	-
2031/32	-	375	-	-	-	600	-	-
2032/33	-	375	-	-	-	600	-	-
2033/34	-	375	-	-	-	600	-	-
2034/35	-	375	-	-	-	600	-	-
2035/36	-	375	-	-	-	600	-	-
2036/37	-	375	-	-	-	600	-	-
2037/38	-	375	-	-	-	600	-	-
2038/39	-	375	230	-	-	600	-	-
2039/40	-	375	230	-	-	600	-	-
2040/41	-	-	230	1,000	100	800	-	90
2041/42	-	-	230	1,000	100	800	-	90
2042/43	-	-	230	1,000	100	800	-	90