2017

INTEGRATED RESOURCE PLAN

Énergie NB Power

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1. TO OUR CUSTOMERS

The electricity industry is changing. NB Power is part of this change and in the process of reinventing what has remained the same for the last century. While the electricity system in New Brunswick is in the initial stages of change, NB Power will be focused on making sure customers are at the forefront of receiving safe reliable service while ensuring clean energy and a strong grid for generations to come.

NB Power knows that our customers are looking for their utility to be a sustainable business and they want to have a say and a stake in how the system is planned. This Integrated Resource Plan (IRP) was developed with the consideration of customer priorities. These priorities are related to areas that are of concern to our customers: affordability; today and tomorrow, clean energy and the environment, and what part do customers play as new options and services are made available today and into the future.

Affordability

Clean Energy/
Environment

Customer Options/
Programs & Services

At the same time, NB Power has an obligation to

- deliver safe, reliable energy at low and stable rates
- achieve 40 per cent of electricity sales from renewable resources by 2020
- ensure a sustainable energy supply plan for the future

These obligations are entrenched within the *Electricity Act* and therefore become law for NB Power. These obligations are also foundational to this IRP.

This IRP is built with the consideration of customer priorities that were identified through public input. This input was gathered through three public sessions and through an online survey as well as written submissions. This input will allow NB Power to develop solutions in the future that will respond to what customers care about most.

A summary of what was said during the public sessions is provided in Section 9 – Community Dialog Sessions. A separate document was also prepared entitled “What was Said Final Report” which can be found in Appendix 1 of this IRP.

2. INTRODUCTION

Since 1920, NB Power has provided New Brunswick with a secure, reliable and competitively priced supply of electricity. Over the years, the supply mix has grown from a small, 5 MW hydroelectric generating station in Musquash to one of the most diverse systems in North America, which currently consists of 13 generating stations comprising nuclear, hydro, coal, oil and diesel, as well as power purchase agreements from various privately owned renewable and natural gas generating facilities.

NB Power has more than 6,800 km of transmission lines, and over 21,000 km of distribution lines. NB Power is committed to providing safe, reliable and efficient power to over 400,000 direct and indirect customers in New Brunswick.

NB Power's corporate mission, vision and values:

MISSION	VISION	VALUES
To Be Our Customers' Partner of Choice for Energy Solutions	Sustainable Energy for Future Generations	• Safety • Quality • Diversity • Innovation

The mission, vision and values define the long-term strategy for NB Power. The mission describes the purpose of the organization, while the vision paints a picture of what the desired future will look like. The values represent what is important to the company and how employees operate and behave while working with internal and external stakeholders to conduct business and work towards achieving the corporation's mission and vision.

NB Power's mission has been, and continues to be, customer focused. NB Power's relationships with customers and stakeholders constantly evolve to enhance this focus. By continuously demonstrating its core values of safety, quality, diversity, and innovation, NB Power will become customers' partner of choice for energy solutions. It is recognized that the electricity industry is changing, and as a result, NB Power's vision of *Sustainable Energy for Future Generations* will reflect this new priority.

The Canadian Electricity Association defines sustainable electric utilities as those "Pursuing progressive business strategies and activities that meet the needs of the present, while enhancing the environmental, social, and economic resources that will be needed in the future."[1]

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[1] https://electricity.ca/deliver/sustainability/sustainable-electricity-program/

At NB Power, sustainability is factored into every decision and every plan for the future. It's about balancing efforts to deliver competitively priced electricity while maintaining long-term corporate health. It's about harnessing the power of renewable energy sources and safeguarding the environment by moving away from fossil fuels.

Sustainability represents goals embraced by NB Power as a company—protecting low rates, reducing the carbon footprint and being responsible to the communities in which employees and customers work and live.

With this in mind, NB Power continues to focus on the three pillars of sustainability: the environment, society and the economy.

NB Power will continue to focus on identifying innovative environmental technologies that will benefit customers and further reduce its carbon footprint, by continuing to deliver electricity from a diverse mix of non-emitting resources such as wind, hydro, nuclear and other renewable resources and to ensure stable power rates and reliable supply.

This report is intended to provide a plan for NB Power to move towards sustainable electricity. This plan represents a snapshot into the future that reflects current conditions, assumptions and forecasts. It is a plan that incorporates what our customers care about most: affordability, clean energy, and new personal options and services. The plan, however, will continually evolve as conditions change and as new sustainable opportunities emerge over time. It is intended that the plan be reviewed on a triennial basis to reflect the latest industry developments and information.

While the assumptions in this IRP are based on best information available at the time of writing, analysis was performed to capture uncertainties associated with the major assumptions. This analysis can be found in the Sensitivity Analysis section of this report.

With respect to Greenhouse Gas (GHG) regulation, NB Power has included within the base analysis, compliance with current federal regulation related to the reduction of carbon dioxide emissions from coal-fired electricity. The current regulation allows existing coal facilities to operate to their normal end of life. NB Power has included in this report a sensitivity that includes carbon pricing consistent with the Pan-Canadian Framework on Clean Growth and Climate Change. This pricing was then applied to a carbon tax system and a cap and trade system. Also included was a sensitivity of early coal shut down by 2030.

The Government of New Brunswick is working with NB Power and the federal government to develop a made-in-New Brunswick GHG management strategy and to explore all options to minimize the cost to New Brunswickers. As the direction on the carbon strategy for New Brunswick becomes clearer, NB Power will review the necessity to refresh this IRP.

2.1. Background

NB Power continues to work in pursuit of three key strategies as outlined in its 30-year Strategic Plan.

1. **Become among the best at what we do**. NB Power will target being a top performer (top 25 per cent) as compared to other similar public and private utilities in North America;
2. **Reduce our debt so we can invest in the future**. Systematically reduce debt to ensure NB Power is in a financial position to invest in new generation and transmission when necessary to ensure stable rates for New Brunswick; and
3. **Reduce and shift electricity demand**. Invest in technology, educate customers and promote efficiencies that will help reduce and shift demand for electricity and ultimately defer or remove required future investment in generation.

These strategies are intended to allow NB Power to replace future generation as needed while taking advantage of future energy options and operating as efficiently as possible. They are also intended to help our customers understand how to reduce electricity consumption and shift demand patterns without affecting personal comfort.

Operating under the authority of *Electricity Act* requires NB Power to file every three years with government and with the Energy and Utilities Board (EUB) an Integrated Resource Plan that outlines projected demand requirements and planned sources of supply.

NB Power is directed by the *Electricity Act,* and regulated by the EUB to operate under the following policy objectives

- to provide low and stable rates
- to ensure a reliable system
- to meet the requirement of a Renewable Portfolio Standard (RPS)

NB Power must submit annually an application before the EUB of its electricity sales rates and a ten year strategic, financial and capital investment plan. The EUB considers the IRP as an input into their decision-making process when reviewing a rate application. The EUB also considers the IRP when reviewing NB Power’s application for approval of any capital project above $50 million.

This IRP fulfils NB Power’s renewed commitment to develop a long-term plan that considers economics, the environment, long-term societal interests, and various sensitivities of these features.

This IRP has been developed through a customer engagement process established to seek feedback from customers and to provide guidance to the plan through the following questions.

1. **Affordability:** What are your priorities related to rates and debt repayment, investing into more customer options, transitioning to a clean energy future, and purchasing renewable power from other jurisdictions versus promoting local supply?
2. **Clean energy and the environment:** What are your priorities related to moving away from fossil fuels, paying more for clean energy, NB Power being a leader in clean energy and energy efficiency, and whether it is important that electricity for New Brunswick is made in New Brunswick?
3. **Customer Options:** What are your priorities related to NB Power offering customer options to better manage their electricity use, personally investing in equipment and technology to save electricity, purchasing an electric car, generating your own electricity, participating in a time-of-use rate program, and is it NB Power's job to manage electricity use and costs?

This IRP analysis is part of a continual process that requires periodic load and resource updates as conditions change and evolve over time provincially, nationally and even globally. It reflects the evolution of NB Power's strategic planning approach as it embarks on a strategy to more closely align the IRP development activities to the business planning process. As technologies and circumstances change, so will the recommendations presented in the IRP. The IRP helps set NB Power's vision of the future.

2.2. The IRP Process

The planning process that encompasses the evaluation of supply and demand is called integrated resource planning. This IRP includes long-term strategies to ensure NB Power's obligation to supply in-province load is met, that renewable resource regulations are followed, and that resources comply with air emission standards. These long-term strategies provide long-term rate stability, reliability of supply, economic efficiency, environmental acceptability and financial viability.

The development of this IRP required in-depth analysis in three key areas:

1. Energy efficiency and demand considerations (which reduce and shift demand) as well as supply considerations.
2. Reliability and security of supply.
3. Policy and regulatory considerations.

External feedback is an integral part of the IRP process. NB Power communicated and consulted with customers and key stakeholders including First Nations, to ensure an optimum long-term supply of electricity for New Brunswick. The analysis was done to ensure an appropriate balance of the three key areas listed above while considering economic, environmental and societal implications.

Historically, the choices that were made to supply future electricity needs were based predominantly on the overall cost effectiveness of available options. These customarily encompassed a wide range of traditional generation technologies including hydro, nuclear, and fossil fuel generation such as coal, natural gas and oil. The cost effectiveness view continues to be prevalent today, but because of the uncertainty of the supply of imported hydrocarbon fuels and the volatility of corresponding fuel prices, combined with more stringent environmental requirements (including greenhouse gas (GHG) regulation and compliance with the renewable portfolio standard), a new focus of choosing environmentally preferred power generation will be required. The plan must be realistic and ensure that all supply-side options, including the environmentally preferred power generation choices, provide the appropriate level of reliability, and at reasonable costs.

In addition to supply options, consideration was also given to energy efficiency and demand management programs that will help manage the load requirements for New Brunswick. These programs were developed to deliver demand reductions and achieve the appropriate level of cost-effectiveness to New Brunswick consumers. The demand reduction programs are part of an overall approach called Energy Smart New Brunswick or Energy Smart NB. This approach focuses primarily on reducing and shifting demand and includes investments to modernize the grid. The latter will allow the introduction of new technologies to help customers manage their electricity needs more effectively. Grid modernization will enable these new technologies while ensuring grid stability. Grid modernization will also allow NB Power to operate more efficiency and to provide increased reliability and enhanced service to customers. More detail related to Energy Smart NB is provided in the sections that follow.

The IRP is NB Power's long-term plan that seeks to answer the following questions.

1. What is the current supply of electricity and what is the cost of delivering it using existing technology?
2. What impact does the current electricity supply have on the environment?
3. How do we ensure a reliable supply of power now and going forward?
4. How will changes in society and industry impact New Brunswick's future need for electricity?
5. What new technologies and techniques can NB Power use that will be the most cost-effective, reliable and sustainable?

To create the IRP, NB Power follows a well-defined process that is standard across utilities. The following diagram depicts the key elements of a step-by-step process used to answer the questions identified above.

Figure 1: IRP process

The IRP process can be broken down into a series of steps.

1. Look at the existing system and make certain assumptions about the corresponding parameters (such as fuel prices or polices/regulations going forward).
2. Look at the life expectancy of the existing power plants and expiry dates of the power purchase agreements.
3. Determine the long-term forecast of in-province electricity requirements.
4. Compare long-term supply with long-term requirements, to identify the gap.
5. Research all future supply and demand options and rank them according to cost.
6. Check that the least-cost options are reliable and that the renewable portfolio standard is met. If so, the viable supply and/or demand option feeds back to 3) and 4) to meet the gap.
7. Provide energy literacy and seek input from stakeholders through a public engagement process to determine appropriateness of all supply and demand options.

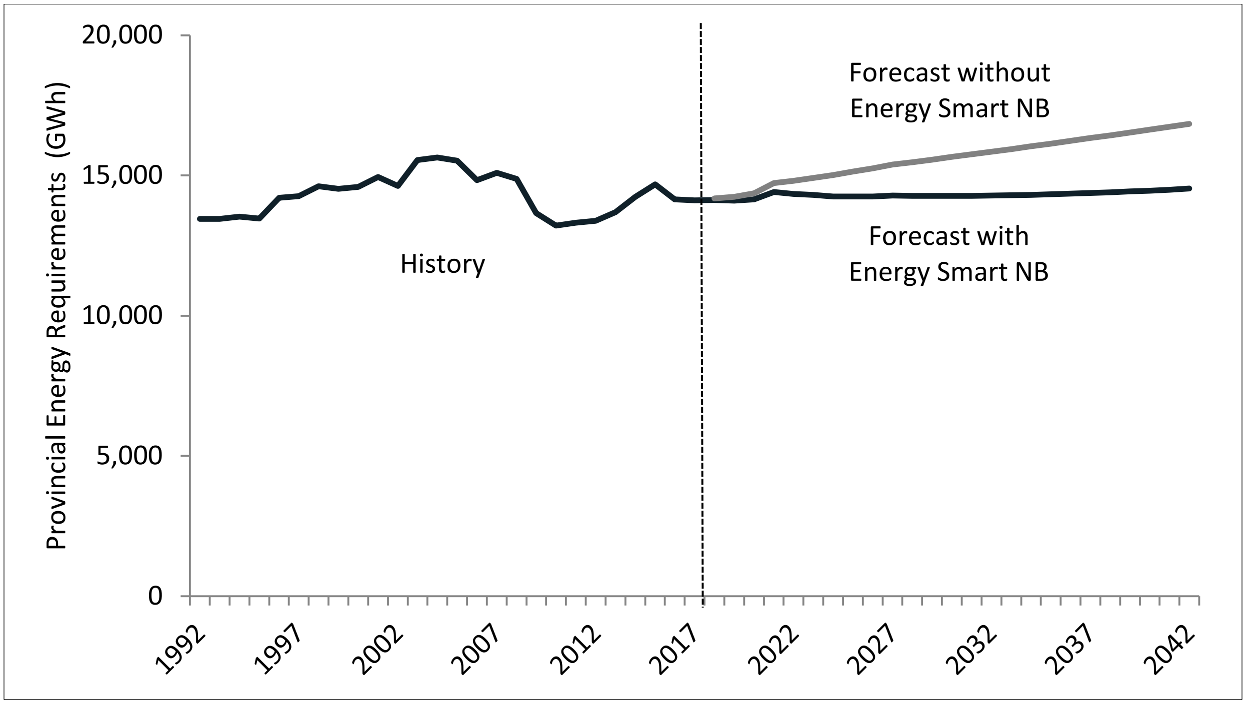
8. Give consideration to any option identified through public engagement by checking against the criterion in Step 6 and, if appropriate, then feed these back to 3) and 4) to fill the gap.

2.3. Basis of this IRP

The IRP assesses New Brunswick's future demand requirements based on population, customer expectations, electricity needs for households and businesses, and promoting economic growth in New Brunswick. The least-cost expansion plan responds to the in-province electricity needs including reserve requirements.

As New Brunswick's electricity needs have changed, particularly with changes in industry, so has NB Power's grid. The figure below shows how NB Power's electricity requirements decreased in the 2008/09 and 2009/2010 periods. NB Power subsequently responded by removing two generation assets at Grand Lake (in 2010) and Dalhousie (in 2012). It is expected that with the reduction in historical demand from previous demand reduction programs, as well as new initiatives to reduce and shift demand in the future, new utility supply resources to meet peak demand will not be required until well into the future. The program to reduce and shift demand called Energy Smart NB, is discussed and evaluated in this IRP. The potential impact of the Energy Smart NB on future electricity requirements is also shown in the figure below.

Figure 2: Historic and forecast future electricity requirements for New Brunswick



Ultimately, NB Power is responsible for ensuring that adequate electricity is available to serve New Brunswick customers today and tomorrow. In addition to this long-term load requirement, this IRP also seeks to establish a development plan that responds to the *Electricity Act* and operates under the policy objectives to provide low and stable rates, to ensure a reliable power system and to meet the requirements of the RPS.

In the near-term, to contain costs, NB Power must optimize its existing assets and utilize its interconnections to buy and sell electricity.

In the medium-term there is a requirement to meet the RPS that directs NB Power to supply 40 per cent of the electricity it sells in New Brunswick from renewable resources such as biogas, biomass, solar, hydro, wind or renewable purchases by 2020. Creating a more efficient system will also play a role to achieve the RPS through grid modernization, new customer options and reducing and shifting demand.

Over the longer-term the end of life of existing resources must be recognized and the appropriate responses made for continued reliability of supply.

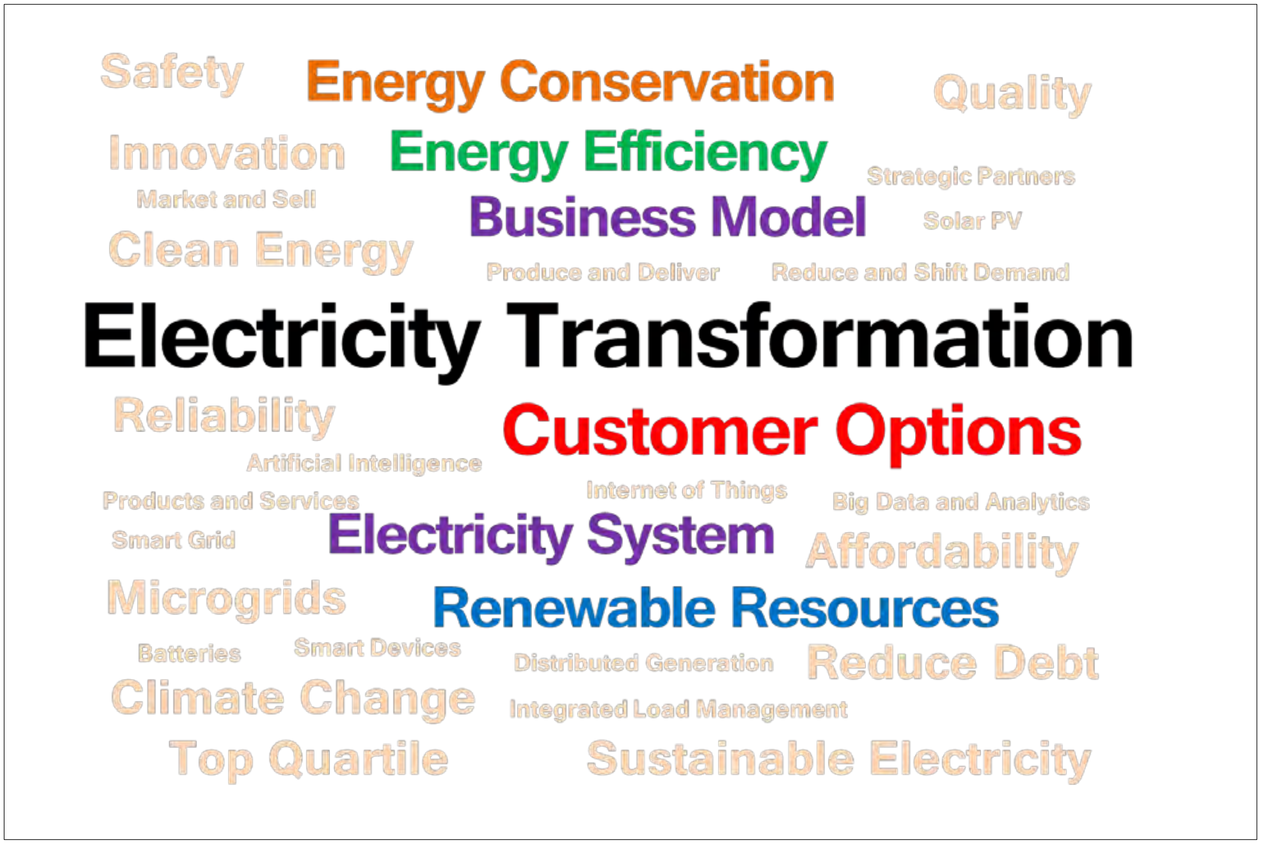
This IRP presents the least-cost plan encompassing both supply and demand options to meet the forecasted NB Power in-province electricity requirements over a 25-year horizon. To meet this requirement, viable supply, energy efficiency and demand management options were analyzed extensively and incorporated into the plan with existing supply resources to determine the least-cost integrated (supply and demand) plan. This was done with consideration of environmental regulation and fuel price volatility. The resultant long-term plan was then measured against the vision of sustainable electricity supply, maintaining long-term rate stability and ensuring reliable electricity supply for New Brunswick.

The IRP results and recommendations presented in this document are based on various assumptions and forecasts that are subject to change. Flexibility of the least-cost integrated plan is essential and that the mix of options selected in this portfolio remain robust with changes in critical assumptions. This IRP has performed sensitivity analysis to measure the impact of the variation of individual critical parameters as well as the effects of the variation of several parameters occurring at the same time. This provided greater assurance that the long term integrated plan remained the least-cost choice under the changed conditions.

2.4. Electricity Transformation

Since the last IRP in 2014, the global electricity industry has seen unprecedented change. In particular, the distribution electricity system is changing in ways that have remained the same for the last century. As shown in Figure 3, the lexicon within the electricity industry is quite extensive and the electricity systems are becoming more complex but a theme has emerged to help explain the change.

Figure 3: NB Power Transformation



The primary driver to this change is the ever increasing availability of new **customer options**. These options will be part of the choices available by customers to satisfy a combined desire to lower their electricity costs and to be more environmentally sustainable all the while ensuring reliable supply. With the ever increasing presence of new technologies and digitalization, NB Power expects that more personalized choices will be available in the marketplace for our customers. NB Power is now thinking of new ways to foster this new ecosystem and so this becomes the starting point of **electricity transformation**.

The electricity system built in New Brunswick has essentially remained the same for almost 100 years. The system began to grow for the benefit of all New Brunswick starting in 1920 and today, a solid foundation is in place that includes a reliable and diverse generation supply along with a robust and stable transmission and distribution system.

Electricity is sometimes taken for granted and often little thought is given to the source of the power that comes out of an electrical outlet. The electric power system was designed as the ultimate in plug-and-play convenience, seemingly as dependable as the sun rising and setting.

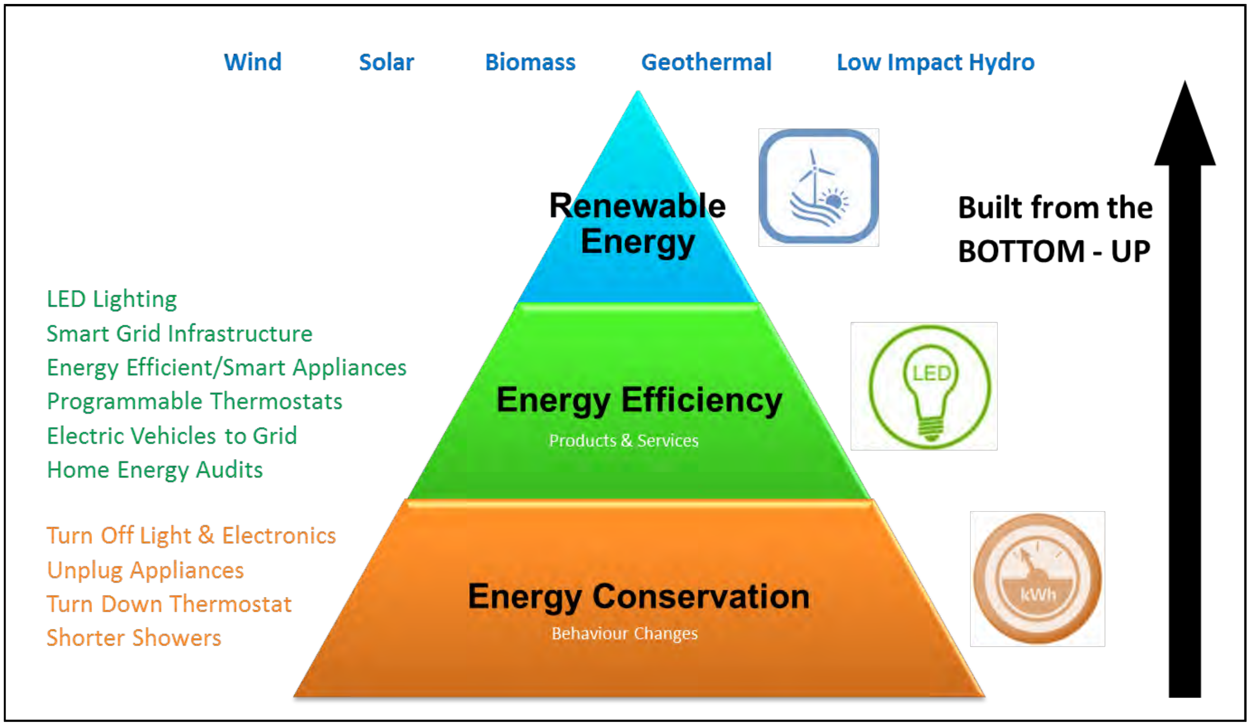
But what is not realized is that the electricity system that has been built over the last 100 years traditionally operates by flowing electricity in one direction; from the central generators through the transmission and distribution systems and delivered to homes and businesses throughout New Brunswick. However, as customers begin their journey to personalize their electricity needs, the flow of electricity begins to travel in the opposite direction. This two way flow of electricity can cause the distribution system to become less stable and has reliability implications. So NB Power needs to think about redesigning the **electricity system**.

And while the physical electricity system needs to change, so too does the business model. Today, NB Power's business of producing and delivering electricity relies heavily on the consumption of electricity from customers. As customers personalize their energy needs this can impact electricity sales and therefore revenues. This will impact NB Powers ability to recover costs as well as pay down debt. So NB Power needs to think about redesigning the **business model**.

Consideration of this transformation is essential in this IRP analysis. The response to the physical and operational changes of the system as well as the business model enhancements begins with ensuring a solid foundation that includes reliability and security of supply as well as the integration of cost effective **conservation**, **energy efficiency** and **renewable resources**. This foundation will include smart grid infrastructure and grid modernization that will allow the development of a shared platform for customers to participate and connect to as they personalize their electricity needs and for NB Power to manage the operation of the system to ensure continued reliability at the lowest cost. What NB Power is embarking on is essentially building the energy pyramid as shown on the following page.

The energy pyramid is built from the bottom up. At the base of the pyramid are foundational customer activities that ensure the most efficient electricity usage by providing educational messaging to customers to help them make simple behaviour changes. This is followed by introducing technologies to help customers and utilities to further manage demand. Smart grid or grid modernization technologies are introduced at this stage as well as related products and services that can be offered to customers. Emphasis is made on cost-effective conservation and energy efficiency measures that help to reduce the system requirement. This activity results in fuel savings and defers the need to build new capital intensive generating resources in the future. These activities also help to reduce customer's energy consumption which results in savings on their monthly bills.

Figure 4: Building the Energy Pyramid



Smart grid development, also known as grid modernization is also categorized as an energy efficiency activity because it increases the efficiency of the electricity production and delivery systems through improved utilization and lower transmission and distribution losses. This is why smart grid development is sometimes referred to as "intelligent efficiency" by the American Council for an Energy-Efficient Economy. The development of smart grid has an added and important benefit because it becomes an enabler for the consideration of increased intermittent renewable resources such as wind and solar, as well as future electricity storage. These comprise of the renewable energy activities at the top of the pyramid and are activities available to both utility and customer.

Energy Smart New Brunswick

NB Power recognizes that advancements in technology are dramatically changing the way energy gets produced, delivered, and consumed, and we must change as well to provide our customers with the best that energy can offer. NB Power is also responsible for anticipating the energy needs of our province far into the future and is taking the right steps now to provide for sustainable energy for all New Brunswickers.

NB Power is therefore implementing Energy Smart NB as a customer focused approach that will see investments made in three key areas and will lay the foundation for important long-term benefits for our customers.

Figure 5: Energy Smart NB Logo

Energy Smart NB is designed to support NB Power's direction with a special emphasis on reducing and shifting demand. Formerly referred to as the "Reduce and Shift Demand Program," this initiative was first launched in 2011. Energy Smart NB addresses a number of opportunities and challenges that require fundamental changes in the way NB Power operates and provides energy to its customers and includes three interrelated components.

1. **Smart Grid:** Investing in technologies, processes, and systems to build and operate a smarter, cleaner, more reliable and efficient power grid.
2. **Smart Habits:** Helping our customers develop habits that save energy and money.
3. **Smart Solutions:** Offering customers products and services that save time, energy, and money.

Energy Smart NB is a direct response to NB Power's mandate, to promote the efficient use of energy and conservation of energy in the Province, by developing programs and initiatives in relation to energy efficiency, energy conservation, demand-side management, as well as integrating renewable energy. Energy Smart NB in its entirety is evaluated in this IRP. Section 8 (Energy Efficiency, Demand Management and Smart Grid) of this report provides an overview of Energy Smart NB.

3. EXECUTIVE SUMMARY

The following results of this IRP provide information regarding the strategic course of action that NB Power should consider to meet future resource needs. The integrated plan shown in Figure 6 indicates:

- Energy efficiency, demand management and grid modernization through Energy Smart NB is vital to the IRP. This IRP has included an aggressive but cost-effective capacity and energy reduction schedule that assumes a savings of 621 MW and 2.3 TWh by 2041/42. This electricity reduction potential provides a net present value of approximately $1.1 billion to NB Power and to New Brunswick ratepayers over the study period.

- A significant change is occurring in the electricity industry because of new customer options and personalized choices that will change their electricity consumption. This trend will continue and a new partnership with customers will be developed in the near term. Energy Smart NB will be the catalyst to this new partnership.

- Through the Government of New Brunswick's Locally Owned Renewable Energy Projects that are Small Scale (LORESS) regulation, 80 MW of cost-effective community energy resources are targeted by 2020. In addition, 13 MW of Embedded Generation is also targeted by 2020. These programs along with Energy Smart NB will help meet the 40 per cent RPS requirement.

- GHG levels for the planning period remain below the 2005 historical levels.

- Millbank and Ste. Rose life extension is the most economic choice for continued peak load requirements in response to their retirement in 2031.

- Mactaquac Generating Station continued operation is reflected through life achievement activities that will extend the life of the facility to 2068.

- The planning period of the 2017 IRP extends to 2041/42, which includes the retirement of the Point Lepreau, Belledune and Coleson Cove generating stations. It is recognized that significant investment will be needed to replace these assets. NB Power will look for opportunities and options to separate and spread this investment over a broader period.

- NB Power will continue to monitor existing supply technology options and costing as well as emerging technologies to ensure latest information is available for subsequent IRP's and as the need for new supply requirement approaches.

Figure 6: Integrated expansion plan

FY Ending	Integrated Plan	Scheduled Retirements
2018	Energy Smart NB (621 MW)	
2019		
2020	Embedded Generation (13 MW)	
2021	LORESS (80 MW)	
…		
2025		Grandview (-95 MW)
2026		Grand Manan (-26 MW)
2027		Bayside (-277 MW)
…		
2031	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (-496 MW)
2032		
2033	Mactaquac Life Achievement	
…		
2040	Lepreau Replace-in-kind (660 MW)	Point Lepreau (-660 MW)
2041	Natural Gas Combined Cycle - NGCC (3 x 412 MW) Millbank / Ste Rose (2 x 99 MW)	Belledune (-467 MW) Coleson Cove (-972 MW)
2042		

In summary, the strategic direction recommended over the immediate term is:

- Continued development of the Locally-owned Renewable Energy Projects that are Small Scale (LORESS) and Embedded Generation programs to meet the RPS;
- Continuation of the Energy Smart NB plan with increased development in the long-term; and
- Continuation of technical work with regards to new generation options and business models that might be viable in New Brunswick, especially options from customer owned renewable resources.

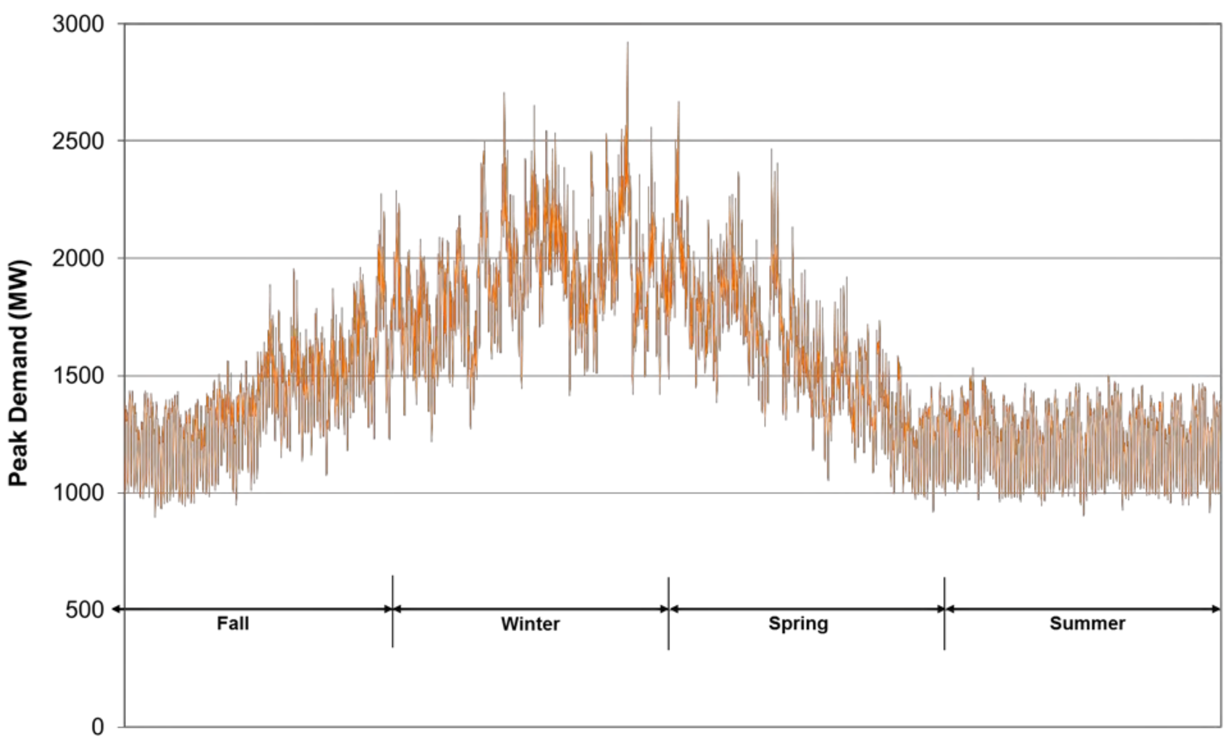
4. OUR SITUATION

New Brunswick's in-province electricity requirements, like most regions, combine the needs of residential, commercial, industrial and municipal customers. Like all electric utilities, NB Power's challenge is to match production with customers' needs on an instant-by-instant basis as those needs change. However, New Brunswick's in-province load is unique in several ways:

- High penetration of electric space heating (approximately 63 per cent of residential customers; Nova Scotia, by comparison, has approximately 37 per cent electric space heating).
- High penetration of total load (historically in excess of 25 per cent) associated with relatively small number of energy-intensive industries (such as pulp and paper, and petroleum sectors).
- High penetration of electric water heater load (over 90 per cent of residential customers have electric water heaters).

As a result, New Brunswick is very dependent on electricity with unique load characteristics that offer both challenges and opportunities. The use of electric heat in New Brunswick is largely responsible for peak load requirements on the coldest day of the year, nearly doubling the daily average peak load requirements during the summer period.

Figure 7: New Brunswick load profile showing seasonal and daily variations



And within any day the load requirements may shift by 400 to 600 megawatts, mainly caused by electric space heating and/or electric water heating requirements. This daily variation is a challenge because it means that a power plant of this size must be available for as little as one hour. This contributes to low generation utilization—averaging less than 50 percent which then can have a direct impact on electricity rates. Advances in technology provide opportunities to leverage this unused capacity, and those opportunities become even more compelling when customers become more knowledgeable and proactive energy consumers.

This load profile creates a significant opportunity to improve system efficiency for NB Power since more than 50 per cent of the utility's generation is only required for three to four months of the year. Increasing the system load factor will also improve the load factor on the transmission and distribution system with additional potential for deferral of transmission and distribution capital requirements.

Traditionally, NB Power has relied on its hydro resources (approximately 900 MW) to accommodate the majority of daily load variation. However, the availability of this hydro resource is sometimes limited because of the limited hydro storage capability. But just as important are the periods of high water flows, when hydro generation is operating at full capacity and therefore cannot be varied without spilling water. With the current capacity of about 300 MW of intermittent renewable wind resources on the New Brunswick system the limited hydro resources have become fully utilized and there are times when other more expensive generation such as oil is required to operate more often. For example, NB Power sometimes runs a 300 MW oil fired unit at Coleson Cove for system flexibility during very low or high river flow periods.

To help achieve opportunities to improve system efficiency, NB Power's Energy Smart NB plan will reduce and shift demand that will better manage the varying load profile. Energy Smart NB taken in its entirety is a foundational approach meant to transform the way NB Power designs and operates the system. Energy Smart NB is comprised of demand-side programs that will promote lower consumption through conservation and energy efficiency for customers. In addition, investments into a smart grid program will be made that will modernize the NB Power distribution grid to:

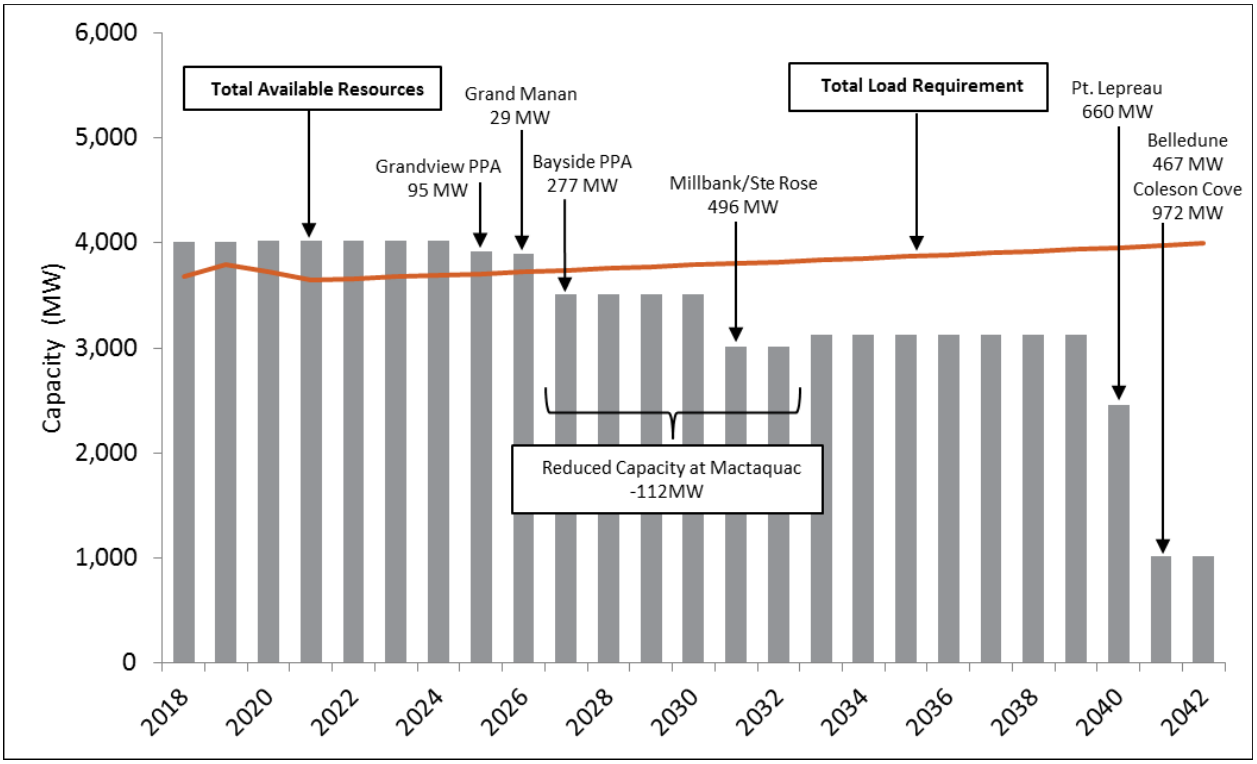
- provide customers more granularity of their electricity usage
- accommodate and manage increasing amounts of distributed energy resources on the distribution circuits
- reduce distribution and transmission line losses
- improve restoration time and automate actions in the event of faults that disrupt power delivery on the circuits

Energy Smart NB in its entirety will be evaluated in this IRP.

On the supply side, NB Power has a diverse generation mix of hydro, nuclear coal and oil – both carbon and non-carbon emitting generation. In addition, NB Power has power purchase agreements with generators that use natural gas as well as power purchase agreements with renewable generation such as wind and biomass. The capacity from the entire supply resource available to NB Power currently stands at about 4000 megawatts. However over the course of the 25-year planning horizon, these supply resources will decline as generators age and retire and power purchase agreements expire.

The following chart is useful to help understand how the current demand and supply situation will change over the planning period.

Figure 8: Total load requirement[2] versus total available resources



This situation establishes the starting point for this IRP analysis. This chart shows the need for new capacity starting in 2027 and increasing requirement over time. The remaining sections of this report will describe in greater detail the aspects of this chart as well as other critical factors used to determine the most appropriate plan that will include building new resources through an integrated approach comprised of both demand and supply options. These options will also consider those available to customers to manage their electricity consumption.

[2] NB Power's total electricity requirement includes customer demand plus losses plus reserve capacity. In the event of emergencies, NB Power must provide reserve capacity equivalent to 20 per cent of its firm load or its largest unit (whichever is larger).

5. EXISTING SYSTEM

5.1. Load Forecast

The load forecast for the IRP is based on the NB Power Load Forecast 2017-2027 completed in the summer of 2016.

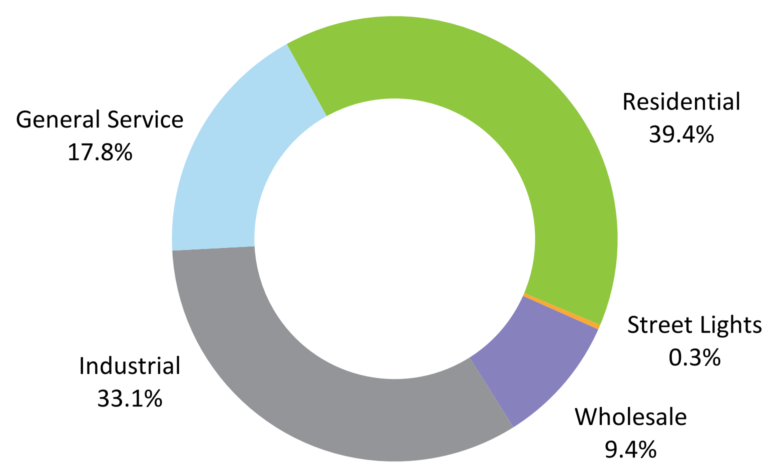
For forecasting purposes, electrical load is divided into three main groups: residential, general service and industrial. The grouping reflects similarity in end uses of electricity requirements within the group. Also, the customers within each group are to some extent homogenous. As a result, electricity requirements within each group are affected by similar factors.

The residential, general service and industrial forecasts are separated into six customer classifications

1. residential
2. general service
3. street lighting
4. industrial distribution
5. industrial transmission
6. wholesale (includes the sales to the preceding classifications by the municipal utilities in the cities of Saint John and Edmundston)

The relative proportions of NB Power's energy sales in fiscal year 2016/17 to each of the six customer classifications are shown in Figure 9.

Figure 9: NB Power energy sales in 2016/17



Residential

The residential classification is made up mostly of year-round domestic (household) customers. It also includes some non-domestic customers such as farms and churches, which account for less than 3 per cent of the total residential energy requirements. Also included in the residential classification are seasonal customers that account for approximately 1 per cent of the residential electricity requirements.

Figure 10: NB Power representative consulting with customers during a home show

Increases in the residential forecast are driven mainly by the addition of new customers and increasing annual household usage, somewhat offset by reductions associated with energy efficiency and price elasticity.

General Service

Sales to the general service classification include commercial (retail/wholesale, hotel/motel/restaurants, offices, etc.) and institutional customers (hospitals, schools, universities, etc.). As of March 2017, there were approximately 26,000 general service customers served by NB Power, and an additional approximately 5,000 served by the wholesale utilities.

Approximately 70 per cent of general service sales are commercial in nature and are therefore considered to be directly related to the level of provincial economic activity. The remaining 30 per cent of general service sales are to the institutional sector, which is indirectly related to the economic activity in the province.

Industrial

New Brunswick's industrial customers consume about 35 per cent of the total in-province electrical energy.

Industrial customers are divided into two groups:

1. Industrial transmission customers who are served at transmission voltages of 69 kV and above. There are 39 customers served at the transmission voltages. These customers constitute the majority of industrial sales.

2. Industrial distribution customers who are served at distribution voltages less than 69 kV. NB Power serves approximately 1,700 industrial customers at distribution voltages, while the wholesale utilities serve approximately 70 others. Together, they account for approximately 15 per cent of the total industrial electrical energy requirements. The major industrial distribution groups are wood industries, food and beverage, manufacturing, and other operations.

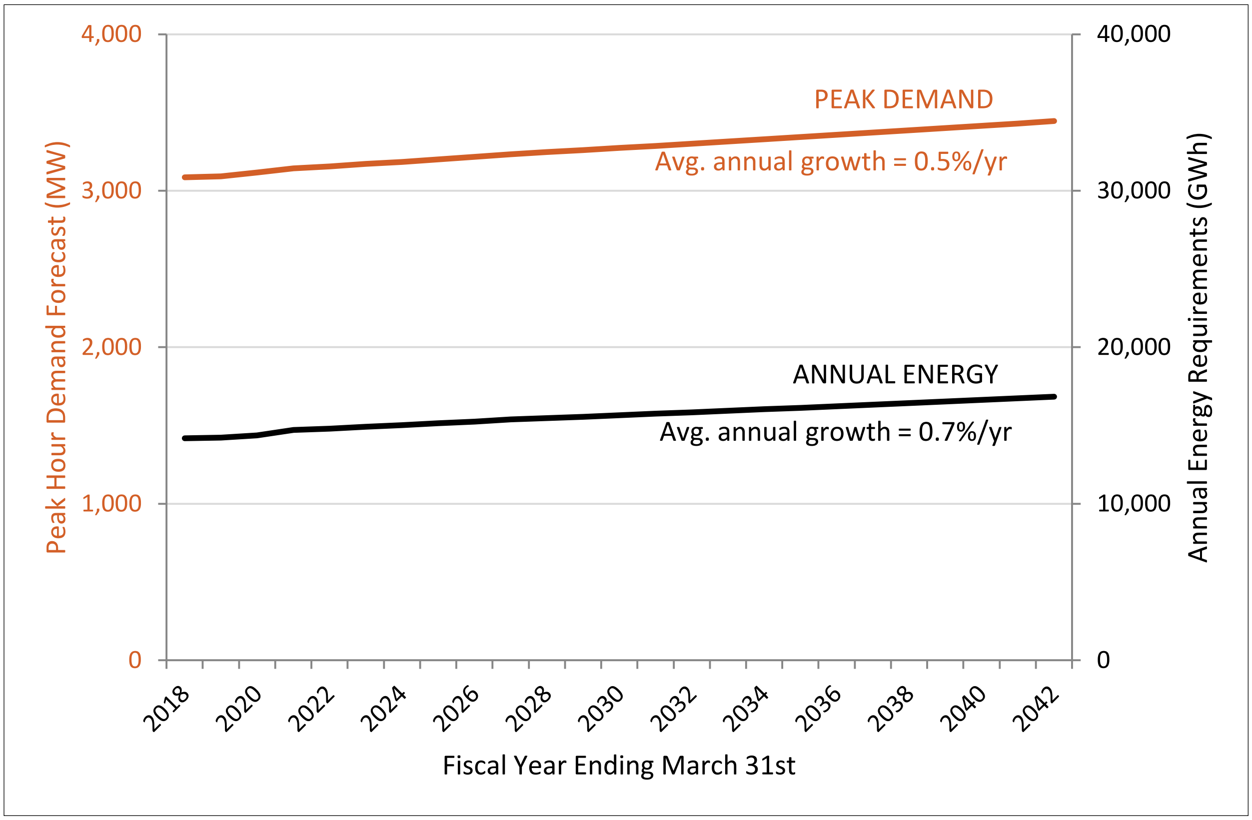
Load Forecast Results

The total customer load is the combined total of the electricity sales to the six customer classifications, plus the transmission and distribution losses related to those sales.

In addition to the total annual energy, the maximum requirement in a one-hour period is also critical for system planning. The maximum energy requirement in a one-hour period is referred to as "peak hour demand." NB Power is a winter-peaking system, driven by a combination of electric space heating and electric water heating in homes and businesses, with the peak demand normally occurring in January or February.

Using forecasts for each customer sector, the data is combined to establish the total in-province load forecast for the period 2017/18 to 2026/27. Beyond 2026/27, the forecast is escalated by class, using a technique that utilizes time-series regression models to project load growth. The forecast includes estimates of energy-efficiency measures that consumers are anticipated to naturally implement. Estimates of energy efficiency and demand reduction programs as part of the Energy Smart NB plan to reduce and shift demand have been removed from the forecast for the purpose of this IRP. This is done to establish the baseline by which the value of this strategy can be measured. The options that make up the overall program to reduce and shift demand will be evaluated and considered as part of the IRP process. The resulting forecast is shown in Figure 11.

Figure 11: Total in-province load forecast excluding demand reduction programs



Note that the loss of load in New Brunswick since its peak in 2004, particularly in the forest products manufacturing industry, leaves the current in-province load at the same level that the utility served in 1995.

The average growth rate for peak demand is 0.5 per cent per year while the average growth rate for energy is 0.7 per cent per year. These growth rates are before the impact of the Energy Smart NB plan.

5.2. Generation Resources

NB Power has a diverse portfolio of generation resources and power purchase agreements from a blend of hydro, nuclear, coal, natural gas, oil-fired thermal and combustion turbines, biomass and wind, as shown in the system map below.

Figure 12: System map

At this time, no new generation has been committed for construction with the exception of power purchase agreements associated with 13 MW of embedded generation projects and 80 MW of community energy projects, both of which are targeted for completion by 2020. The latter is part of a government program to promote locally owned renewable energy projects that are small scale. These programs in combination will help NB Power achieve its regulatory target to have 40 per cent of in-province electricity sales met by renewable energy by 2020.

Since the last IRP, NB Power has assessed options and a decision was made on the preferred option for future of the Mactaquac Generating Station. 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. NB Power will seek the necessary environmental approvals from the province and follow application and review processes for financial approvals as defined by the Energy and Utilities Board.

The current generation capacity and PPA portfolio, as well as other statistics of the NB Power system, is shown in Figure 13.

Figure 13: Existing NB Power Net Generating Capacity[3,4] and other statistics[5]

Generating Capacity Thermal	
Coleson Cove	972 MW
Belledune	467 MW
Total Thermal	1,439 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	1,439 MW
Hydro	889 MW
Nuclear	660 MW
Combustion Turbines	525 MW
Total Generating Capacity	3,513 MW

Power Purchase Agreements (PPAs)	
Kent Hills (Wind)	150 MW
Caribou Mountain (Wind)	99 MW
Lameque (Wind)	45 MW
Bayside (Natural Gas)	277 MW
Grandview (Natural Gas)	95 MW
Twin Rivers (Biomass)	39 MW
St. George (Hydro)	15 MW
Edmunston Hydro	9 MW
Other Renewable	6 MW
Total Power Purchase Agreements	735 MW

Number of Lines	
Distribution Lines	21,121 km
Transmission Lines	6,865 km

Exporting and Importing Capacity	
Export Capacity	2,385 MW
Import Capacity	2,248 MW

Number of Customers	
Direct Customers	355,918
Indirect Customers	45,248
Total Customers	401,166

[3] 30 MW from the Point Lepreau Generating Station is committed to Maritime Electric Company Limited (MECL) in PEI for the life of the unit. Total capability is 660 MW, which leaves 630 MW for in-province needs.

[4] The contribution to capacity for wind generation is calculated as 21 per cent of the installed capacity (i.e., 294 MW installed wind capacity * 0.21 = 61.7 MW). This is due to the intermittency of this resource.

[5] NB Power 2016-17 Annual Report: https://www.nbpower.com/media/739729/2016-2017-annualreport-en.pdf

This diverse mix of generation capability is expected to meet the electricity requirements of New Brunswick well into the future. In addition, NB Power is interconnected with neighbouring utilities for the purpose of importing and exporting electricity, and for increased system reliability. NB Power's electricity exports have contributed to lower rates for New Brunswick customers. The potential for interconnection imports have allowed NB Power to reduce costs by displacing higher-cost generation that would have been required to meet in-province electricity requirements. At times surplus electricity can also be sold that allows increased revenues and the associated profit margins are then used to ensure rate stability.

Each PPA commitment has a term as defined in the applicable contract. Generally, these are fixed dates. The end-of-life dates for NB Power-owned generating stations are less certain. For accounting purposes, they have a life assigned that is based on typical experience for that type of facility. In actual practice, retirements are dependent on an economic evaluation for each unit as it approaches the end of its useful life. For purposes of this IRP, retirement schedules are initially based on the corresponding accounting life, with consideration of a reasonable extension period that could allow the facility to continue to operate without significant capital expenditure. Consideration of life extension potential was made through studies conducted by NB Power plant engineering experts and through economic analysis. The generating stations and PPA's with an end of life occurring within the study period horizon of the IRP are included in the table below.

Figure 14: Retirement schedule

Resource	Fuel type	Capacity (MW)	End of life date
Grandview PPA	Natural gas	95	2024/25
Grand Manan	Diesel	26	2025/26
Bayside PPA	Natural Gas	277	2026/27
Millbank	Diesel	397	2030/31
Ste. Rose	Diesel	99	2030/31
Point Lepreau	Uranium	660	2039/40
Belledune	Coal	467	2040/41
Coleson Cove	Oil	972	2040/41

Further detail is provided in Appendix 2 – List of Assumptions for IRP

5.3. Transmission and Interconnections

The NB Power transmission system is part of the power system infrastructure that lies between the sources of power supply and the substation load centres. The NB Power transmission system has been strategically designed to provide reliable electricity to in-province customers while also providing opportunities to buy and sell electricity with neighbouring jurisdictions.

The NB Power transmission system includes all of the 345 kV, 230 kV, 138 kV and 69 kV transmission lines (6,865 kilometres in total), termination equipment and control equipment to permit the necessary operation of the interconnected transmission network. This system provides the means for delivery of electricity to meet forecast demand requirements under normal operating conditions.

New transmission requirements are driven by a number of potential factors that can include: the need to connect new generation, to meet in-province load growth, maintaining or increasing imports and exports, improvements in system reliability and meeting industry Reliability Standards.

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 20th 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 to 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.

Figure 15: NB Power 345 kV transmission tower

NB Power continuously assesses the transmission system to ensure it meets all reliability standards and provides benefits to New Brunswickers.

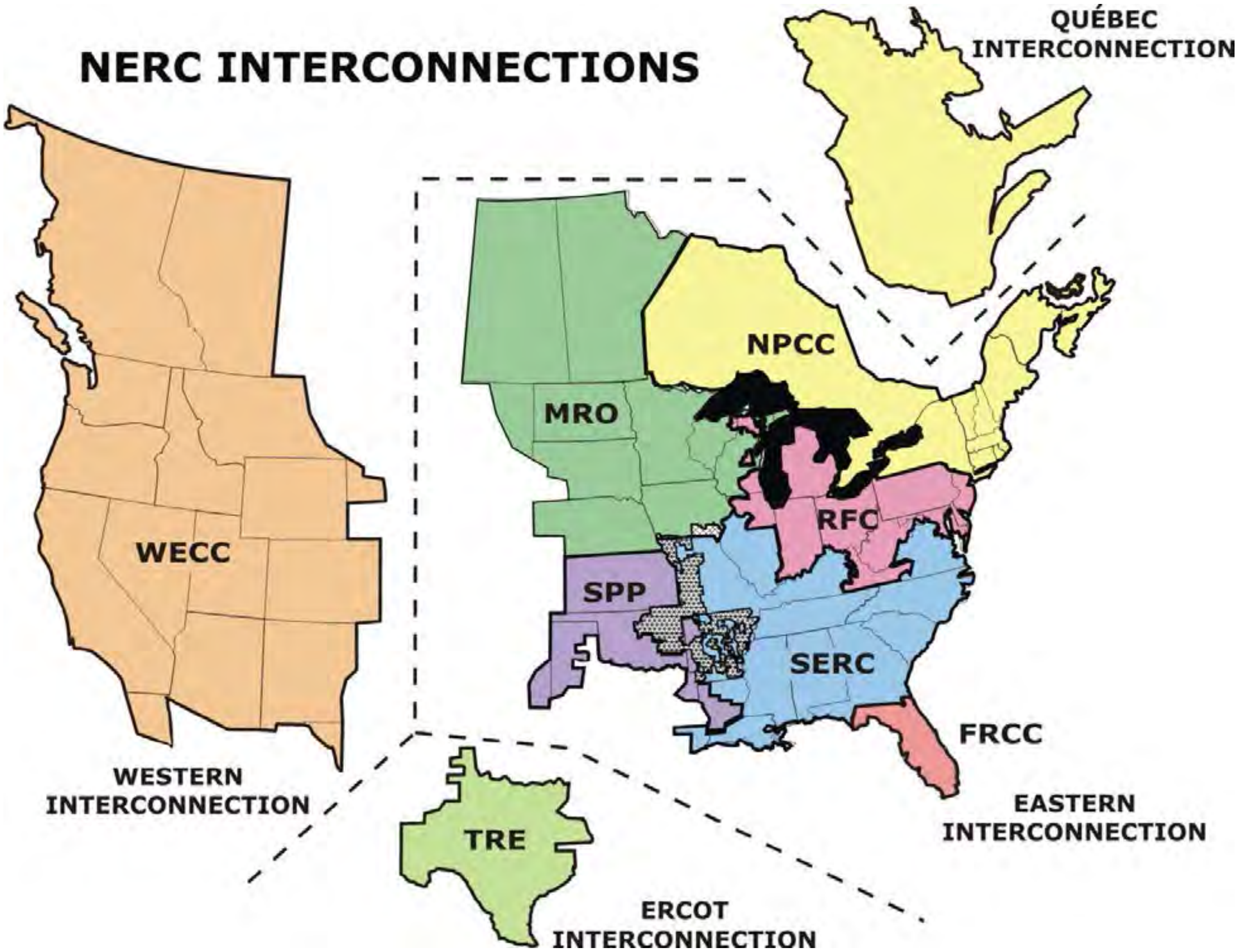
Sufficient transmission capacity is available for in-province load levels and for exports, assuming necessary generation is available in critical areas and during certain times of the year, and that special protection systems are in place in the event of loss of transmission and/or generation equipment.

The transmission system was designed to deliver the existing generation economically to all in-province customers, and to export surplus supply to neighbouring utilities. The ability to import electricity from Quebec, New England, and at times from Nova Scotia, has also been very important to NB Power's ability to lower its costs for the delivery of electricity to its customers. The next 20 years and beyond could see changes to the generation supply types and locations both within and outside New Brunswick. These potential changes in generation supply may require new transmission infrastructure to reliably and economically interconnect them with the NB Power system.

The NB Power transmission system is a small part of a much larger bulk transmission system in the Eastern Interconnection (see Figure 16). NB Power belongs to the Northeast Power

Coordinating Council Inc. (NPCC). The NPCC mission is to promote and enhance the reliable and efficient operation of the international interconnected bulk power system. The geographic area covered by NPCC includes New York, the six New England states, Ontario, Québec and the Maritime provinces.

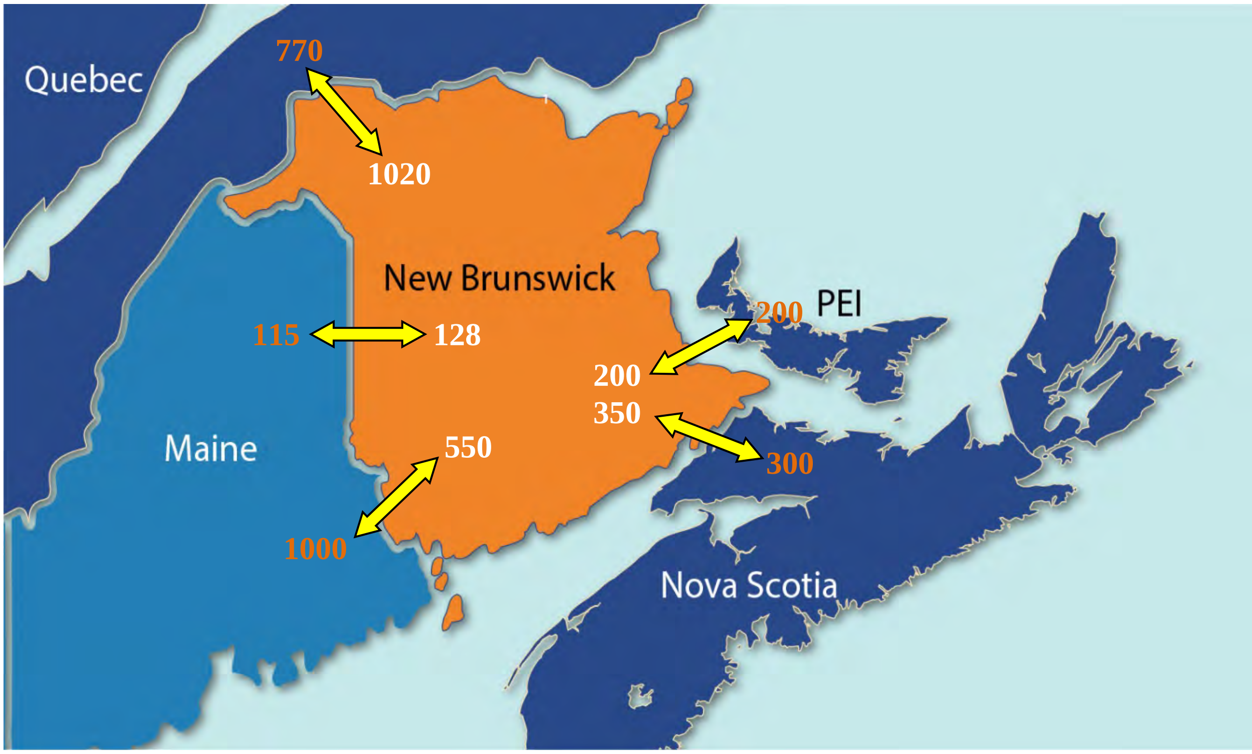
Figure 16: North American regional reliability councils and interconnections



Interconnected transmission lines can be used to transfer electricity from one jurisdiction to another under contractual arrangements, or on a spot market basis and during emergencies. NB Power has always placed major emphasis on developing strong interconnections with neighbouring systems for both economic and reliability reasons.

Out-of-province electricity purchases and/or sales are made under short-term (daily and weekly) contracts or on a spot basis. Actual interconnection capabilities with neighbouring jurisdictions are dependent on system conditions in New Brunswick and other regions at the time of transfer. In the past, the interconnection with New England has enabled NB Power to construct larger, more economical generating units to allow for the purchase and sale of surplus electricity on both a short and long-term basis. NB is also interconnected with Quebec, Nova Scotia and Prince Edward Island (PEI). The interconnections support the system with direct and indirect contributions to capacity reserves, thus reducing the requirement for additional capacity to serve in-province customers. The following chart shows the capabilities of NB Power's major interconnections.

Figure 17: NB Power's winter total transmission import/export capabilities (MW)



Depending on the in-province load and/or the generation dispatch, as well as the condition of the in-province transmission system, these limits cannot always be achieved. The limits can also vary depending on conditions within the interconnected jurisdiction.

Transfer Capability between New Brunswick and Nova Scotia/PEI

The New Brunswick to Nova Scotia and PEI transfer capabilities are a function of the transmission system's transfer capability into the southeastern region of New Brunswick, minus the southeastern region load (mainly Moncton, Dieppe, Riverview and surrounding areas). As the New Brunswick southeastern region load increases, the net electricity transfer capability available to PEI and Nova Scotia is reduced.

Transfer Capability between New Brunswick and Quebec

The NB Power to Hydro Quebec (HQ) transfer capability is the sum of the two high voltage direct current (HVDC) stations, one at Eel River (owned and operated by NB Power) and the second at Madawaska (owned and operated by HQ). The Eel River HVDC Station, shown in Figure 18, has an import/export capability of 350 MW. The total import/export transfer capabilities with HQ are as follows.

- For import from HQ:

Eel River HVDC	350 MW
Madawaska HVDC	420 MW
Radial ties at Eel River and Madawaska[6]	230 MW

- For export to HQ:

Eel River HVDC	350 MW
Madawaska HVDC	420 MW

Figure 18: NB Power's Eel River HVDC Station

Additional HVDC interconnections with HQ are a possibility in the future and will be considered with other regional transmission expansion and refurbishment options. The Eel River HVDC station underwent a life extension project in 2014 in order to maintain its 350 MW transfer capability. The Madawaska HVDC station underwent a life extension in 2016.

[6] Radial ties with HQ are interconnections that can serve a portion of New Brunswick load in isolation of the main NB Power grid.

Transfer Capability between New Brunswick and New England/Northern Maine

The maximum transfer capability from New Brunswick to New England is 1,000 MW. This is the maximum reliable transfer capability assuming all transmission facilities in Maine and New Brunswick are in service. In December 2007, a second 345 kV interconnection was put into service. This development strengthened the New England–New Brunswick interface since the additional interconnection increased transfer from 700 to 1,000 MW, and improved the reliability and reduced the likelihood of separation of the Maritimes from the interconnected New England power system.

In addition to the major interconnections into New England, NB Power can serve isolated loads located in Northern Maine. These interconnections are smaller and serve loads in Northern Maine (approximately 125 MW) and Eastern Maine (approximately 15 MW).

New Brunswick Transmission Requirements

Although the current transmission system in New Brunswick is sufficient to reliably transfer electricity of the existing generation, potential upgrades may be necessary in the future, especially in the southeast of the province as load in the Moncton area grows. Also, the addition of more wind generation in New Brunswick will likely require new transmission to be built. The wind farms currently in service in New Brunswick required minimal transmission infrastructure due to their close proximity to existing terminals and transmission lines. If wind and other intermittent generation are added to the system, the integration of these resources can become more complex due to the balancing of generation, voltage and other power quality issues.

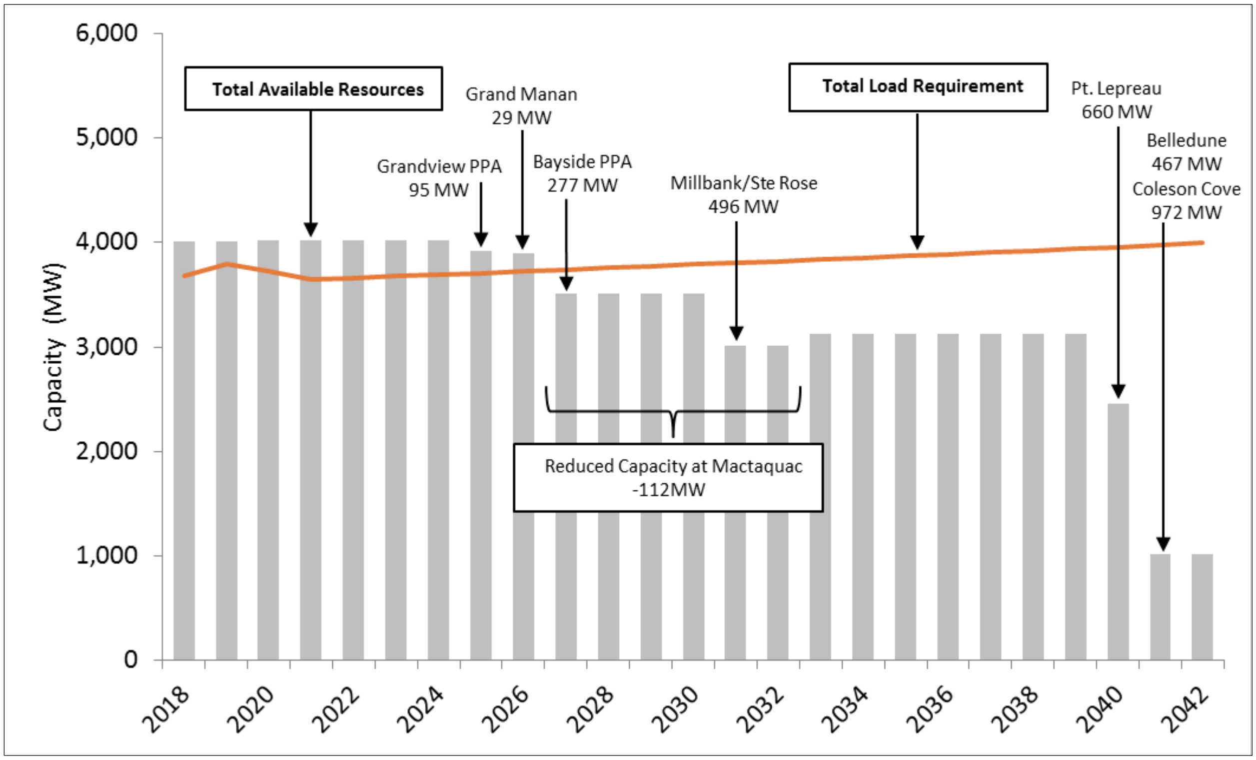
NB Power continues to investigate solutions to future transmission constraints. Obvious solutions include both adding additional transmission as well as strategically locating generation closer to the load requirement such as distributed generation. Another solution exists that could preserve and extend the existing transmission system. This solution includes targeted demand reduction through smart grid technology. This, in conjunction with conservation and energy efficiency initiatives will reduce and shift demand and are intended not only to defer the need for new generation in the future, but also to potentially defer or reduce the need for new transmission infrastructure. More information related to reducing and shifting demand is provided in the sections that follow. The final solution to transmission constraints will be evaluated in a separate study. The results of this IRP will be used to establish the baseline of this study.

5.4. Load and Resource Balance

Like other plants in North America, NB Power's fossil generating stations have normal life spans of approximately 45 years. This provides utility planners with a guide for making decisions on the timing and introduction of possible new generation. The final decision on whether a station will be refurbished or replaced cannot be made definitive until near the scheduled retirement of that station. Conditions (specific to both generation plant and external) will change over time, and this will require reassessment and adjustment of the plan. Assuming the future continuation of both the obligation as a regulated utility to provide reliable service to its customer base, as well as other known conditions such as environmental regulations and renewable standards, NB Power can provide a snapshot of the electricity requirement and assess what options may be available to meet that requirement.

The chart shown in Figure 19 provides a snapshot of the electricity need for NB Power, assuming the generation resources are as described in Section 5.2 (Generation Resources) and depicted by the grey bars in the chart. This is then compared to the current load requirement and growth, including reserve requirements[7] as depicted by the orange line.

Figure 19: Total load requirements and generation resources FY 2018-2042



[7] In the event of emergencies, NB Power must provide reserve capacity equivalent to 20 per cent of its firm load or its largest unit (whichever is larger).

In this load and resource assessment, energy efficiency and demand-side management estimates associated with NB Power's Energy Smart NB strategy have been removed from the load forecast. These estimates have been assumed in the official load forecast with the exception of naturally occurring demand-side management. The load and resource assessment provides the basis for the IRP assessment in which new cost-effective energy efficiency and demand-side management options will be considered. It provides the starting point for consideration of new generation supply as well as reaffirms the value of integrating demand management programs associated with NB Power's Energy Smart NB plan.

From this assessment, the need for capacity will outstrip the resources starting in the 2027 time frame. NB Power's major generating stations at Point Lepreau, Belledune and Coleson Cove will reach the end of their lives and be scheduled for retirement towards the end of the period. When this occurs, NB Power's existing fossil fleet including generators from power purchase agreements (PPA's), representing a total of approximately 3,000 MW of capacity or about two-thirds of NB Power's overall capacity, will be retired. The resources that remain in the very long-term will be hydro generating stations, which on average have 100-year life spans.

It has been assumed in this IRP that all of the hydro assets will be replaced by an equivalent quantity of capacity and renewable energy, with the first replacement being the Mactaquac hydro station. The Mactaquac Generating Station is a run of the river hydro facility with an installed generation capacity of 660 MW. The facility began generating electricity in 1968. Since the 1980s, concrete portions of the hydro station have been affected by a chemical reaction called alkali-aggregate reaction. This reaction causes the concrete to swell and crack and has required substantial annual maintenance and repairs. 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. It is expected that no more than one unit, approximately 112 MW will be unavailable at any one time during the replacement period. At the end of the replacement period, expected in 2033, all units will be fully available. This life achievement recommendation follows three years of expert research, including input from science, engineers, the public and First Nations. This approach will meet all safety and environmental requirements. It will allow NB Power to take into account changes in cost, technology and electricity demand while ensuring compliance with the Renewable Portfolio Standard of 40 per cent in the long term.

The RPS requirement of 40 per cent translates to 75 per cent non-emitting when consideration is made for Point Lepreau production. To ensure long term compliance of this non-emitting target, it has been assumed that Point Lepreau would be replaced in kind after its retirement date. This will also provide long term base load capacity to ensure reliable supply to meet long term in-province load requirement as well as transmission support for continued security of supply in the southern region. NB Power recognizes that other options may be revealed over the next 25 years that could meet reliable base load requirements and non-emitting targets expected in the long term. As the IRP is refreshed, these available options will be considered and evaluated.

While the load and resource assessment shows a shortfall beginning in 2027, it also identifies a surplus of capacity during the transition period from 2018 to 2026. At its peak, the surplus reaches about 500 MW in 2021 and slowly reduces as load grows on the system. During this transition period from 2018 to 2026, the contribution of assets to the system will need to be evaluated and opportunities examined to find markets for the surplus generation other than in-province load.

The generating plant that appears to present the greatest opportunity for obtaining savings during the transition period is the Coleson Cove Generating Station, which currently runs on heavy fuel oil. While this facility is designed as a baseload station, its forecast hours of operation are extremely limited. Its limited operation is a result of a fuel oil cost that makes this plant uncompetitive with other fuels, including purchases in the long term. The Coleson Cove Generating Station has a net output capacity of 972 MW, supplied by three equally sized generators. The plant was refurbished in 2004. Subsequent to that, Unit #3 was modified to co-fire petroleum coke with heavy fuel oil at up to 20 metric tons per hour. At light loads, this represents in excess of 50 per cent of the fuel requirement for that unit. When Coleson Cove is called upon to supply electricity, it will typically be Unit #3 that is dispatched. Because of Coleson Cove's size and the need for this capacity in the winter months, this facility is an important asset to meeting in-province needs.

The opportunity exists to convert two units to natural gas. Factors that will influence the final decision are the capital costs of the conversion, the projected capacity factor, natural gas infrastructure costs, the need to contract for firm natural gas supply and pricing for natural gas in the long term. NB Power continues to evaluate this opportunity. This IRP study has assumed Coleson Cove continues to operate on heavy fuel oil for the life of the facility. Because of the anticipated low operating hours, the condition of the facility will be such that it becomes a very good candidate for life extension at reasonable cost. This study, therefore, has also assumed that this facility is made available for an additional 10 years beyond its normal operating life, with the appropriate costs included for life extension.

The Belledune Generating Station is the only coal-fired facility on the NB Power system. This facility operates at a high capacity factor because of its low cost fuel. The operation of this facility and its greenhouse gas (GHG) emission intensity are now regulated under the *Canadian Environmental Protection Act*.[8] This regulation sets a stringent performance standard for new coal-fired electricity generation units and those that have reached the end of their useful life, which is defined as 50 years in the regulation. In this study, Belledune is assumed to be retired in 2041. If GHG regulations change, these will be included in the next IRP.

As mentioned, no new generation is required in the transition period 2014 to 2026. However, within the transition period, projects considered will include the addition of generation to meet the RPS. To date, wind generation has been the choice to meet this requirement. NB Power has

[8] https://www.ec.gc.ca/cc/default.asp?lang=En&n=C94FABDA-1

recently issued requests under government's Locally-Owned Renewable Energy Small Scale (LORESS) Program. This program will see an additional 80 MW of renewable energy installed by 2020. In addition, NB Power will also add approximately 13 MW under its embedded generation policy by 2020. Going forward, biomass opportunities, small hydro or photovoltaic may be developed. Section 6.1 (Traditional Utility Supply Options) and Appendix 4 (Supply Options) outlines two projects, Grand Falls and High Narrows, which may prove to be economic options during the transition period that will have an impact well beyond the transition period. The development of cost-effective renewable, locally owned community energy projects may contain a combination of renewable options that can also help meet the RPS requirement. Customers will also have new options in the future such as solar and batteries to help manage their electricity needs. These personal choices are available today and are expected to be part of the New Brunswick electricity system in the future.

5.5. Environmental and Sustainability Considerations

NB Power has diversity of supply within its existing fleet of generating assets. This diversity minimizes risks attributed to changing regulations, and helps with security of supply and sustainability for the long term.

Sustainable electricity, as defined by the Canadian Electricity Association, has three basic pillars: environment, social and economic. As set out in its corporate vision of "Sustainable Electricity," NB Power is moving towards a more sustainable source of energy supply for the future, one that focuses on these three pillars.

Each of the three pillars of sustainable energy includes specific principles.

1. Environment
    a. Environmental Impact
    b. Stewardship and Biodiversity
    c. Climate Change
2. Social
    a. First Nations Relations
    b. Communication and Engagement
    c. Health and Safety
    d. Workplace
3. Economic
    a. Economic Value
    b. Energy Efficiency
    c. Security of Supply

5.5.1. Sustainability Pillar - Environment

There are several environmental considerations for NB Power's existing system that have to be factored into the IRP in the environmental pillar of sustainability. Aside from reducing the environmental impact of any new project and adopting a philosophy of strong stewardship and biodiversity, NB Power must also take into account pending changes to environmental regulation. These include:

- further GHG regulations (Carbon Dioxide CO_2) beyond existing coal regulations,
- air pollutant regulations (Sulphur Dioxide SO_2, Nitrogen Oxide NO_x, Total Particulate Matter TPM and Mercury Hg),
- possible changes to the *Fisheries Act, and*
- possible changes to the *Species At Risk Act (SARA)*

Further GHG Regulations
In addition to the current coal regulations, further GHG regulations could be applied to other fuels such as oil and natural gas. This could have an impact on current thermal (GHG emitting) assets including the Coleson Cove Generating Station, as well as on natural gas-fuelled power purchase agreements. On December 12, 2015, Canada inscribed in the Paris Accord its 2030 target of 30 per cent reduction in greenhouse gases from 2005 levels.

To estimate the impact of GHG regulations on future plans of this IRP, NB Power has included a sensitivity that would contain some form of carbon pricing through either a carbon trading scheme or through carbon taxes that would then be used to capture the potential impact on the environment. Included in this sensitivity would be an assumption of the potential cost on the environment from the full carbon cycle of extraction and delivery of various fuels, to the utilization of these fuels to produce electricity. Also included was sensitivity of early coal shut down by 2030. The impact on GHG emissions and the associated costs of these sensitivities can be found in section 10.4 (Sensitivity Analysis) of this report.

The Government of New Brunswick is working with NB Power and the federal government to develop a made-in-New Brunswick GHG management strategy and to explore all options to minimize the cost to New Brunswickers.

Carbon Prices
Within the sensitivity analysis for potential GHG regulation, carbon prices applied were consistent with the Pan-Canadian Framework on Clean Growth and Climate Change[9] approach to pricing carbon pollution. This approach specifies the price on carbon pollution for jurisdictions with an explicit price-based system, the carbon price should start at a minimum of $10 per tonne in 2018 and rise by $10 per year to $50 per tonne in 2022.

[9] https://www.canada.ca/content/dam/themes/environment/documents/weather1/20170125-en.pdf

Pending Air Pollutant Regulations
The two major thermal plants in NB Power's fleet, the Belledune and Coleson Cove generating stations, are equipped with environmental control equipment. Since the equipment was installed, starting in the early 1990s, emissions of SO_2, NO_x and Total Particulate Matter (TPM) have been significantly reduced. The releases of SO_2, NO_x and TPM are relatively low when compared to similar plants in other jurisdictions. New regulations could have an impact on NB Power's thermal assets and some further reductions may be required. NB Power is actively participating in this process with Environment Canada.

The *Fisheries Act* and the *Species at Risk Act (SARA)*
The purpose of Canada's *Species at Risk Act* (*SARA*) is to conserve, protect and recover endangered or threatened species, and to encourage the management of species of special concern to prevent them from becoming further at risk. The Act aims to prevent indigenous species from extirpation or extinction and preserve biodiversity within Canada. Consideration of the *Fisheries Act* and *SARA* are made in current and future thermal generating stations needing further cooling water as an operational requirement to avoid fish kill.

Any changes to the *Fisheries Act* could have an impact on current and future hydro facilities with respect to fish passage. NB Power is proposing a project at Mactaquac to ensure the station can operate to its intended 100-year lifespan with a modified approach to maintenance, adjusting and replacing equipment over time. NB Power will continue to work with the Canadian Rivers Institute (CRI) and Fisheries and Oceans Canada to achieve targeted fish passage goals on the Saint John River as informed by science, ongoing studies, input from First Nations and stakeholders and future regulatory decisions.

The proposed project at Mactaquac will allow for the addition of multi-species fish passage to the existing facilities, using improved technology and taking advantage of an improved understanding of fish behavior resulting from ongoing research by CRI. Environmental flow studies being undertaken by the CRI may lead to enhanced flow regimes.

Funding has been allocated in the project budget of up to approximately $100 million to ensure installation of adequate multi-species fish passage. Under this option, environmental and social impacts during operations would be consistent with status quo, with potential for improvements.

5.5.2. Sustainability Pillar - Social

There are four principles in the social pillar of sustainability, related to

- First Nations relations,
- communication and engagement,
- health and safety, and
- workplace.

Figure 20: Elder George Paul and NB Power employees participate in a cultural awareness and sensitivity workshop

NB Power has recognized the need for renewed focus in First Nations relations, and communications and engagement with customers. These areas have been targeted for improvement as NB Power strives to become top quartile. NB Power recognizes the distinct interests, culture and significance of First Nations and work to build relationships with First Nations communities throughout New Brunswick. NB Power is committed to fostering positive and productive relationships, including the organizations, agencies and government departments that work with and represent First Nation individuals and communities.

NB Power is committed to being one of the select utilities in North America, especially in safety. In November 2013, executive members of NB Power and IBEW Local 37 committed to the re-establishment of NB Power as one of the safest utilities in North America. By signing a renewed commitment, NB Power and the IBEW Local 37 will work together to keep safety as a top priority.

NB Power has been recognized for workplace achievements and for its health and safety culture. This safety commitment also includes promoting electrical safety in the community and through public safety campaigns with radio, TV and newspaper ads as well as school education campaigns. NB Power also hosts contractor safety days for all contractors in the province. Safety champions also meet at least annually with first responder groups within fire departments and police groups to teach and inform them about downed or damaged electrical line safety.

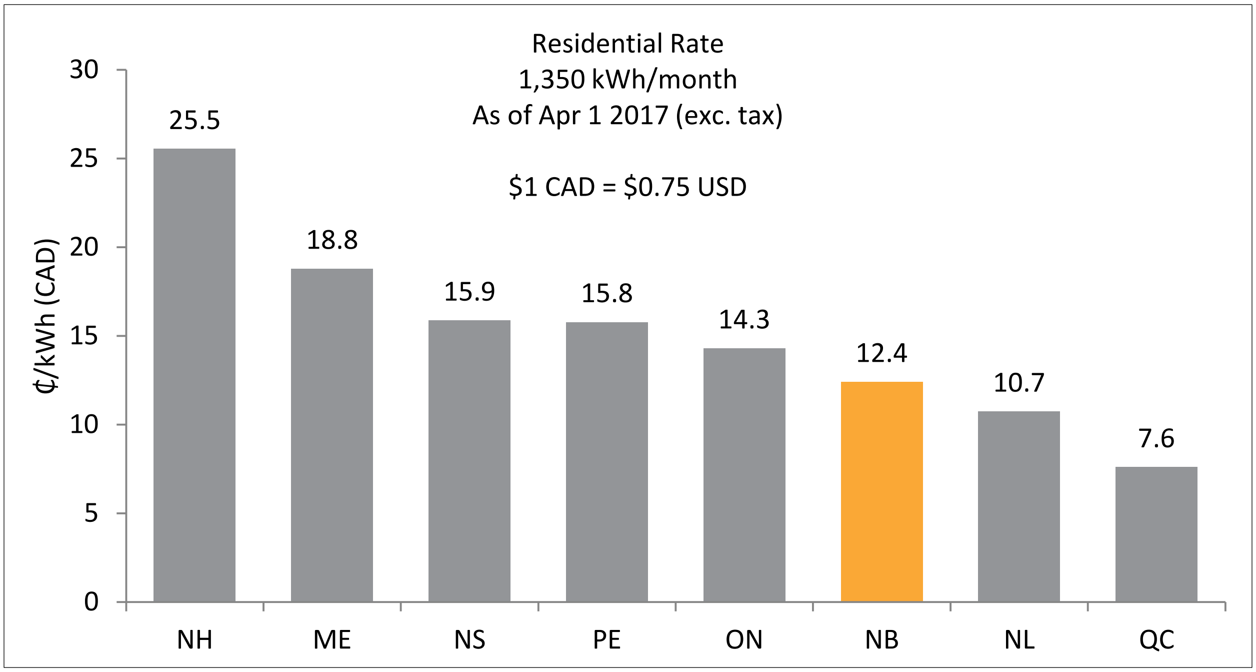
5.5.3. Sustainability Pillar - Economic

There are three principles in the economic pillar of sustainability

- economic value;
- energy efficiency; and
- security of supply.

Important principles to NB Power are providing for economic value, energy efficiency and security of supply. Electricity rates in New Brunswick have been identified as some of the lowest in the region (lower than Central Maine Power, Public Service New Hampshire, Maritime Electric in PEI, and Hydro One in Ontario). Only Hydro Quebec and Newfoundland Power have lower residential rates.

Figure 21 – Residential electricity rates in the region[10]



NB Power boasts a diverse energy supply that includes hydro, wind, nuclear, biomass and fossil fuel-based generation. This diversity minimizes the risk exposure of any one type of generating resource. This characteristic increases the security of supply for NB Power customers. Also important to security of supply is ensuring sufficient transmission and the distribution capacity for the reliable and efficient transfer of electricity. NB Power continues to enhance and

[10] The foreign exchange rate indicated in this chart was current at the time of the publication of the chart, and may not be consistent with the exchange rates used in this study.

maintain the delivery infrastructure and has entered into a multi-year partnership with Siemens to modernize the grid.

In the past, NB Power has achieved varying degrees of success in the area of energy efficiency and demand management. NB Power now has a renewed focus on efficiency and demand management through its Energy Smart NB strategy. This strategy involves demand reduction through energy efficiency programs, and demand shifting through the installation of smart grid infrastructure. Further detail on Energy Smart NB can be found in Section 8 (Energy Efficiency, Demand Management and Smart Grid).

5.6. Renewable Portfolio Standard

NB Power has one of the most diversified generation fleet of facilities in North America. Decisions to develop hydro and biomass resources, made decades ago, and the more recent development of wind resources, have enabled New Brunswick to become a North American leader in diverse renewable energy generation. NB Power currently supplies about 36 per cent of its in-province electricity requirements from renewable sources such as wind, biomass and hydro resources.

The Government of New Brunswick has committed to increasing the development of further renewable energy by the Renewable Portfolio Standard (RPS). This standard is part of the *Electricity Act* that will require NB Power to ensure that by 2020, 40 per cent of its in-province electricity sales are provided from renewable energy. Renewable energy imports will also be eligible to meet the new Renewable Portfolio Standard. This will allow NB Power increased flexibility to meet its obligations under this new standard at the lowest possible cost, which will ensure alignment with its overarching strategy of reducing debt.

Since the goal of the RPS is to reduce the use of fossil fuel generation, that objective can be met by reducing energy usage or by building renewable generation. In most cases, energy efficiency is a less expensive option than building new renewable generation. As a result, NB Power will be aggressively pursuing demand management programs to assist in meeting the RPS target.

In the interest of continuing to improve New Brunswick's environmental performance, energy efficiency is an essential element. By shifting and reducing electricity demand through Energy Smart NB, NB Power will be able to reduce the need for generation from fossil-fuelled plants, thereby increasing the proportion of renewable energy on its system. Innovative programs that result in significant energy reduction will enable NB Power to achieve the 40 per cent RPS in the most cost-effective and efficient manner.

Also helping to achieve the RPS goal of 40 per cent by 2020, additional renewable resources have been built into the IRP. NB Power has assumed that development of energy resources from local small-scale projects would occur as part of government's Locally-Owned Renewable Energy Small Scale (LORESS) program. Request for Expressions of Interests have been released by NB Power that will see the development of incremental renewable capacity installed by 2020.

This IRP has assumed a phased-in approach to the LORESS program so that by 2020, 80 MW of incremental renewable capacity will be added to the system. In addition to this, NB Power will also add another 13 MW of Embedded Generation. These programs will target the installation of renewable energy projects on the distribution system. To manage the integration of this development with the system, NB Power will focus on projects that provide dispatch flexibility and that can integrate with NB Power's smart grid initiative which is part of Energy Smart NB. This approach is explained in greater detail in Section 8 (Energy Efficiency, Demand Management and Smart Grid).

Although not part of the renewable portfolio standard, non-emitting resources such as the Point Lepreau Nuclear Generating Station contribute significantly to reducing the use of fossil fuels. The Point Lepreau Generating Station, which returned to operation post-refurbishment in 2012, provides another 35 per cent of the provincial electricity requirements from non-emitting nuclear energy. Therefore, by 2020, it is expected that 75 per cent of New Brunswick's electricity requirements will be met by non-emitting or renewable sources.

The balance of requirements will come from a mix of renewable and non-renewable resources in order to maintain a reasonable level of generation diversity. These resource options can be found in Section 6 (Supply Options).

The key objectives served by the RPS are:

- Low and Stable Energy Prices – Integrating additional renewable energy will help protect from the cost volatility of electricity generated from fossil fuels;
- Energy Security – Developing additional indigenous renewable energy will lessen NB Power's dependence on imported fossil fuels; and
- Environmental Responsibility – Additional renewable energy will reduce NB Power's greenhouse gas and associated emissions by reducing fossil fuel electricity generation.

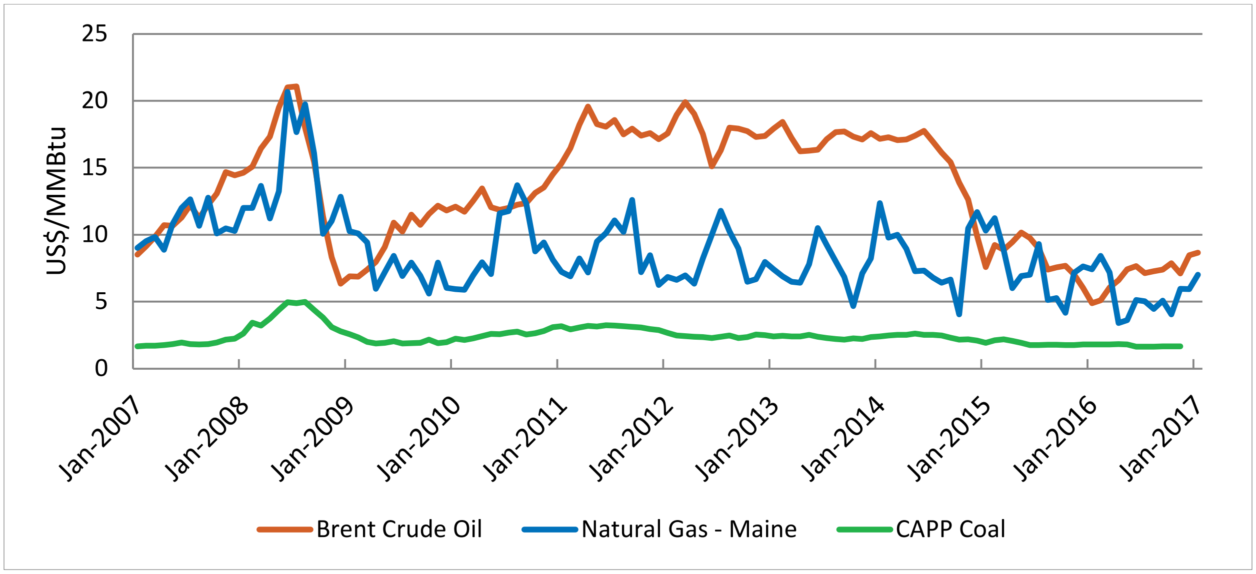
5.7. Fuel Price Forecast

It has been mentioned that NB Power has one of the most diverse power systems in North America. This means that there is a direct dependence on various sources of fuel including coal, oil and nuclear, and an indirect dependence on natural gas and biomass through power purchase agreements.

NB Power purchases coal, #6 heavy fuel oil, #2 light fuel oil and nuclear fuel. It also has exposure through PPAs, to natural gas and to wholesale market prices for electricity purchases. NB Power's fuel and purchased power costs to serve in-province electricity requirements have averaged between about $500 to $600 million per year over the last 10 years.

Hydrocarbon fuel prices have had a history of volatility and uncertainty. The graph shown in Figure 22 provides an indication of how fuel prices have varied since January 2007. By having a diverse fuel mix, NB Power mitigates the risk with much of these price variations.

Figure 22: Fuel price indices history



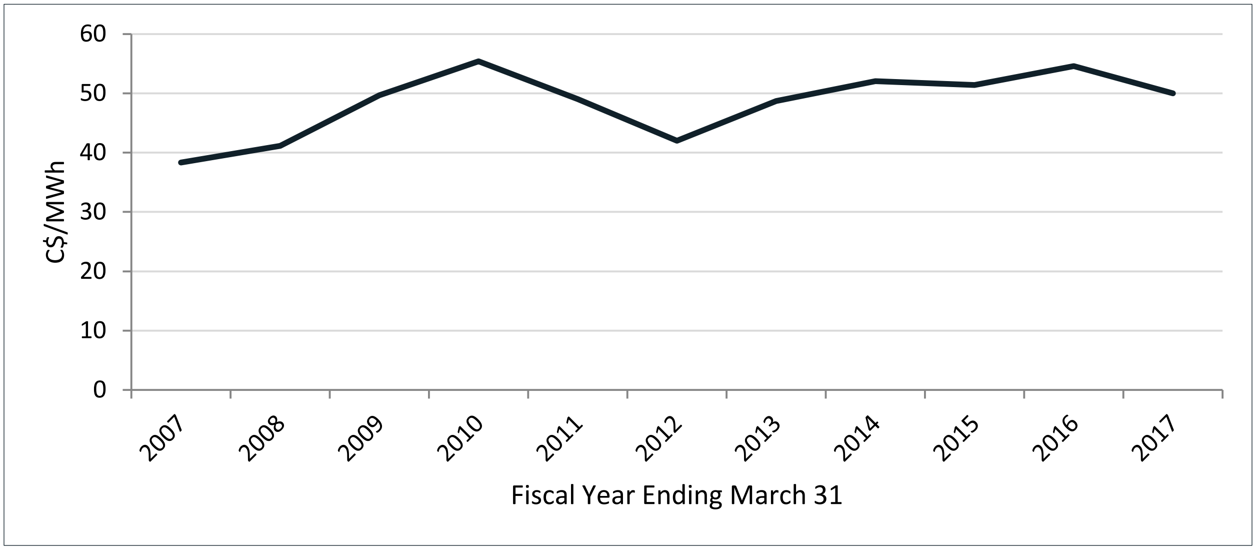
The indices are for trading hubs for the commodity indicated. There are many trading hubs for the various commodities, for example

- Brent Crude Oil – an index that reflects world oil prices
- Natural Gas – delivered in Maine
- CAPP Coal - thermal coal, from Central Appalachian region of the U.S.

The natural gas prices in Maine are indicative of the price that NB Power pays for natural gas fuel, but are not exact in that they do not account for added transportation costs of getting the fuel to the burner. Also note that the prices shown in the previous graph are for an average index price over the applicable month. Daily prices are more volatile than monthly prices.

Fuel and purchased power prices have continually increased over the past several years with the increasing fuel and purchase power costs and increasing volumes of electricity sales. As shown in Figure 23, the average fuel and purchased power price has trended upwards over the past 10 years with an average annual growth of about 2 per cent per year. Note that the calculation excludes hydro generation to remove the impact of widely varying annual production.

Figure 23: Historical average fuel and purchased power price

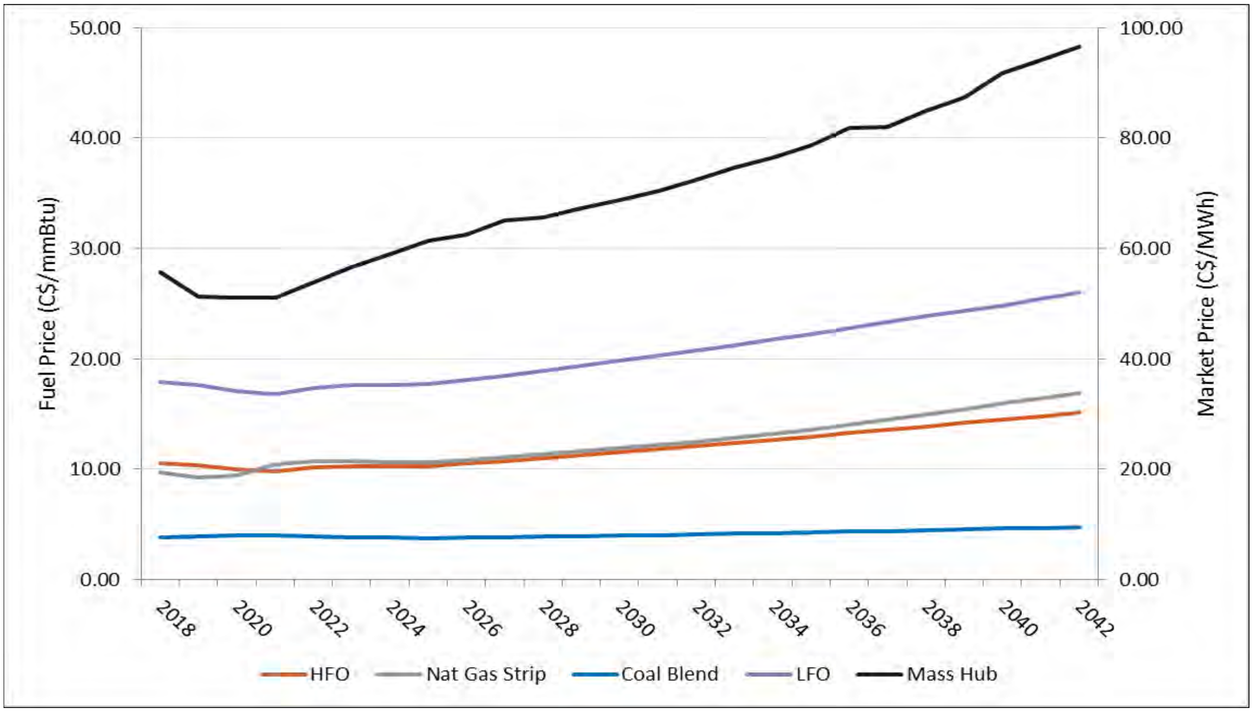


The higher prices seen in the initial part of the period was related to the combination of fuel price variation and changes in the in-province electricity requirement. It was during the period 2008 to 2010 where in-province electricity requirement was negatively influenced because of a significant decrease in industrial load. The in-province electricity requirement then began to stabilize and increase slightly after 2010. Fuel prices also varied during this period as was shown in Figure 23.

Looking forward, the primary source of information for the long-term fuel and market price forecasts used in this IRP study was based on forecasts obtained from Energy Ventures Analysis Inc., an external consultant specializing in this area. Energy Ventures Associates is a leading source for the price assessments of commodity markets and fuel prices used in this IRP.

The first three years of the fuel price forecast used in this IRP was based on the most recent available NB Power budget. The budget forecast was based on the applicable forward prices at time of budget preparation. For the years beyond the available budget numbers, forecasts were obtained from Energy Ventures Associates. The resulting forecast is in US dollars of the applicable year (nominal dollars). The US dollar values were then converted to Canadian dollars utilizing a forecasted exchange rate. The resulting fuel price forecast is shown in Figure 24 with the corresponding data provided in Appendix 3 (Fuel and Market Price Forecast).

Figure 24: Fuel price forecast



The market prices shown in the chart are Massachusetts Hub (Mass Hub) prices and are highly correlated to natural gas prices. The Mass Hub price index sets the base market price of electricity that NB Power buys and sells against.

As mentioned, natural gas pricing is indicative of prices for natural gas delivery in Maine plus added costs for delivery to power plants. The source of gas could come from the remaining Sable off-shore reserves or from Marcellus shale gas region located mainly in Pennsylvania. Natural gas could also be sourced from western Canada. The availability and pricing of these sources rely on the sufficient availability of pipeline capacity in the future. Other sources in the future could come from LNG where transportation could be through a combination of ships, pipeline as well as trucking. Regardless of the source, it was assumed that delivered long term prices would be competitive. The decision to source specific gas relates more to security of long term supply and ensuring reliable delivery that is most cost effective. NB Power continues to investigate these alternative sources and transportation options.

In addition to the above base fuel prices forecast, this IRP provided upper and lower bound price scenarios. This allowed for an analysis for possible future fuel prices that differ significantly from those assumed in the reference case. As a synthesis of the scenarios in this IRP, low fuel price and high fuel price cases were applied. The effect of these sensitivities is analysed in detail in Section 10.4 (Sensitivity Analysis).

5.8. Long-Term Financial and Economic Parameters

5.8.1. General Introduction

An estimate or projection of the values of certain financial parameters is required to determine the levelized cost of electricity (LCOE) of each of the potential generation options. LCOE is the net present value of the total cost stream of a given generation option over its economic life to generate 1 kWh of electricity, including the cost of capital, fuel, operation, maintenance and administration, external environmental costs as applicable, and income taxes payable. LCOE is used to evaluate and compare the relative economics of each of the potential generation options. Section 7 (Results of Supply Analysis) provides the results of the LCOE analysis.

The financial parameters considered in this IRP include:

- the consumer price index
- the electric utility construction price index
- the foreign exchange rate, and
- the weighted average cost of capital (WACC)

These financial parameters are also used in other analyses or applications, including those related to demand-side and energy efficiency management, Strategist modelling,[11] rate impacts and generally in other present value (PV) analyses.

This section summarizes and documents how these estimates or projections were arrived at.

5.8.2. The Consumer Price Index

The consumer price index, which is used to adjust operation, maintenance and administration costs in future years, is projected to increase by two per cent per year. The projection was informed by the most recent Bank of Canada *Monetary Policy Report* [12] that was published in January 2017. It was also informed by a review of the yield spread between Canada Long Bonds versus Canada Real Return Bonds.

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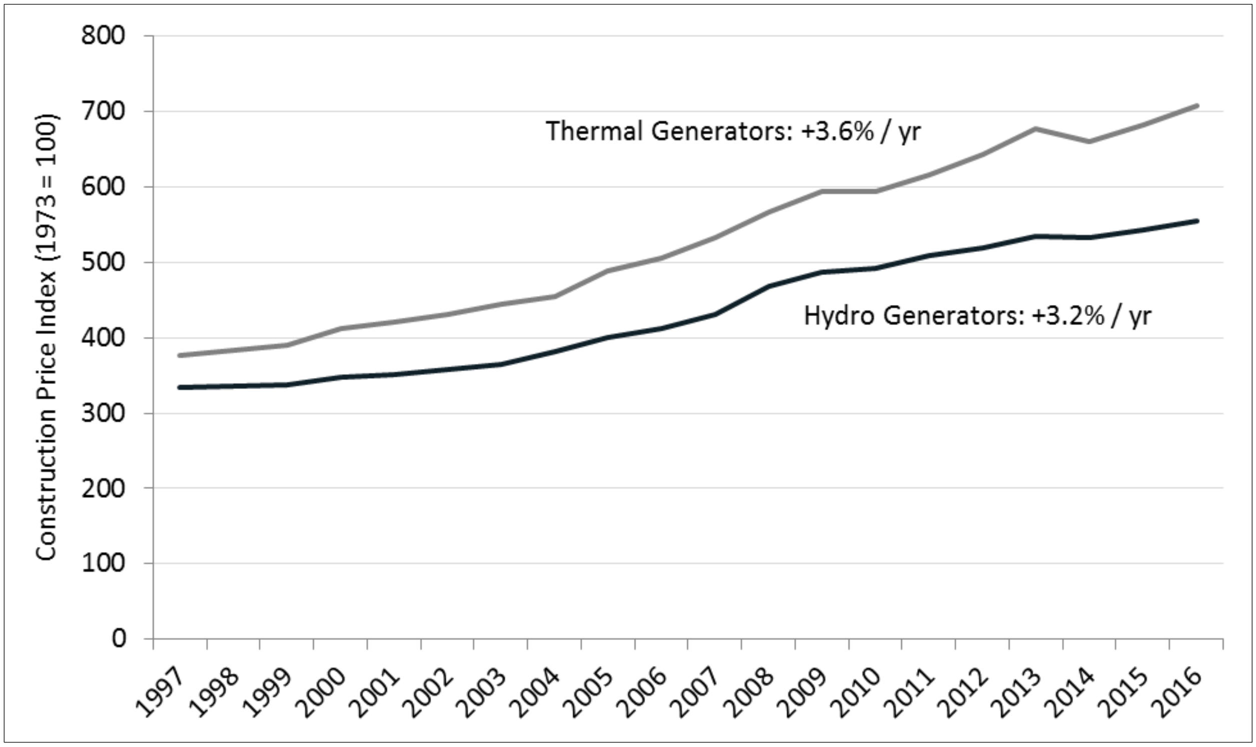
[11] *Strategist (*formally called *PROSCREEN II)* is a proprietary computer software program developed by *Ventyx,* an *ABB* company and is widely used by electric utilities for IRP purposes. The New Brunswick EUB has reviewed and approved the use of the *PROSCREEN II* model, the predecessor to the *Strategist* model, for system planning purposes.

[12] http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf

5.8.3. The Construction Price Index

The electric utility construction price index has escalated on average between 3.2 and 3.6 per cent per year, depending on the type of development project. This history is taken the most recent information from Handy Whitman publication of Public Utility Construction Costs [13] and shown in Figure 25. Two historical construction price indices are shown, based on activities that include thermal generation projects and hydro projects.

Figure 25: Historical Construction Price Index



This chart shows that historical annual increases for plant construction costs have varied from a low of 1 percent to a high of 8 percent in any given year. As mentioned, the long term growth is very dependent upon whether consideration is made that includes thermal generation construction, which had higher cost increases over the last 20 years than hydro generation costs. This IRP has assumed a growth in construction prices consistent with this historical perspective. Distinct growth assumption was also applied consistent with historical trends for thermal generators as well as hydro generators. In arriving at these projections, it was assumed that the global requirement for electricity infrastructure investment would accelerate as capital stock turnover continues with ageing infrastructure during the 2017/18 to 2041/42 planning horizon. It is expected that the prices of industrial commodities (such as structural steel, copper, concrete, etc.) will continue to increase in response to this continuing demand.

[13] https://www.wrallp.com/about-us/handy-whitman-index

Sensitivity analyses have been performed in this IRP to capture uncertainties in the major assumptions. The effect of these sensitivities on future capital costs and the impact on the plan can be seen in Section 10.4 (Sensitivity Analysis).

5.8.4. The Foreign Exchange Rate

Many factors affect the exchange value of the Canadian dollar vis-à-vis the US dollar. The main factors are

- the terms of trade (i.e., the relative prices of oil and other commodities that Canada exports vis-à-vis product that Canada imports)
- interest rate differentials between Canada and the U.S., and
- purchasing power parity, i.e., the inflation rate in Canada vis-à-vis the U.S.

The foreign exchange rate currently stands at approximately USD/CAD = 1.35. This means that one US dollar will purchase 1.35 Canadian dollars. Over the short-term (next four years), this exchange rate is not expected to change significantly. The following is based on recent currency forwards.

	USD/CAD
2018	1.33
2019	1.33
2020	1.32
2021	1.31

The long-run exchange rate has been assumed as USD/CAN = 1.18 beginning after the tenth year of the planning period. Foreign exchange rates have a direct impact on fuel and market prices since these are traded in US dollars. To capture uncertainty in exchange rates, sensitivity analysis was performed to capture changes in fuel and market prices.

5.8.5. The Weighted Average Cost of Capital

A public investor such as a government-sponsored enterprise may have different costs of debt, debt ratios, etc., compared to a private investor. Therefore, the Weighted Average Cost of Capital (WACC) will have two different calculations, one that is representative of public investors, and one that is appropriate for private investors.

The Weighted Average Cost of Capital (WACC) is defined as follows:

WACC = r x (1-t) x DebtRatio + ROE x EquityRatio

where:

r is the interest rate for debt
t is the corporate income tax rate
ROE is the return on equity (after tax)

$$\textbf{DebtRatio} = \frac{\text{Debt}}{\text{Debt + Equity}}$$

$$\textbf{EquityRatio} = \frac{\text{Equity}}{\text{Debt + Equity}}$$

Figure 26 summarizes and documents how the WACCs for the two different classes of investors were calculated.

Figure 26: Weighted average cost of capital

Calculation of the Weighted Average Cost of Capital

Common assumptions

Canada Bond - Long Term	4.25%
Corporate Income tax Rate	30%

After-Tax Weighted Average Cost o Capital (WACC):

Developer	Credit Rating	Debt Ratio	Equity Ratio	Long Bond Rate	Spread	Guarantee Fee	Interest Rate	Return On Equity	WACC
Private	BBB	60%	40%	4.25%	225 b.p.	0%	6.50%	11.0%	7.13%
Public	A+	80%	20%	4.25%	100 b.p.	0.65%	5.90%	5.9%	5.90%

General Remarks

1. WACC is generally used by companies to evaluate investment decisions. The rate is used to discount the after-tax cash flows arising from a given investment.
2. A reputable and creditworthy private power producer, such as Emera, Fortis or Enbridge, has a BBB credit rating.
3. The credit dating 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+.
4. For projects developed by NB Power, it is assumed that such projects are 80% debt-financed, and that a loan guarantee of 0.65% applies. The ROE for NB Power was assumed to be equivalent to the debt dinancing rate.
5. It is assumed that a private investor, would have a debt ratio of 60% with a levered ROE of 11%.

6. SUPPLY OPTIONS

6.1. Traditional Utility Supply Options

The supply options available in this IRP comprise of a mix of generating choices that include different sizes, fuel supply, operating characteristics, and costs. The following list provides all supply options considered in this IRP. Included in the list are broad categories that include conventional supply options, alternative supply options and existing supply, life extension and conversion options.

- Conventional Supply Options
  - Nuclear
  - Natural Gas
    - Combustion Turbines
    - Combined Cycle
  - Hydro
    - Grand Falls Additional Power
    - High Narrows
  - Interconnection Purchases
    - Lower Churchill
    - Other Interconnection Purchases – HQ Expansion Projects
- Alternative Supply Options
  - Small Hydro
  - Wind
  - Ocean Power
    - Tidal Stream
    - Wave
  - Combined Heat and Power
    - Biomass
    - Fuel Cells
    - Microturbines
  - Biomass Bubbling Fluidized Bed
  - Municipal Solid Waste
  - Solar Photovoltaic
  - Enhanced Geothermal
  - Pumped Hydro Storage
  - Compressed Air Energy Storage
- Existing Supply, Life Extension and Conversion
  - Millbank and Ste. Rose Life Extension

These options include both conventional and renewable options, most of which have been in commercial operation. Consideration is also given to projects that are pre-commercial in nature, and high-level costs are provided for these options. It should be emphasized that these options and costs are based on information and experience available to date, and that no provision has been made to predict what new options may be available in the future, including potential improvement in costs. They reflect the most recent "snapshot" of available options and costs. All options, with detailed descriptions can be found in Appendix 4 (Supply Options). A summary of the input parameters and costs can be seen in tabular form in Appendix 5 (Project and Operating Cost Parameters).

The supply option description and parameters provided in Appendix 4 (Supply Options) were obtained from Hatch Energy (Hatch) and NB Power staff. The study provides high-level estimates of plant performance and cost data for each proposed alternative. The estimates provided in this study are order-of-magnitude estimates and, accordingly, were based on limited and incomplete data. Therefore, while the work, results, estimates and projections within the study may be considered to be generally indicative of the nature and quality of the study, they are not definitive. This means that when making final decisions on selecting and implementing supply options, more detailed engineering will be performed to provide greater certainty in the final cost estimates.

The cost estimates provided by Hatch reflect New Brunswick locations, although specific sites were not selected for the alternatives except in cases involving additions or modifications to existing NB Power generation assets.

Each renewable power alternative estimated in this study assumed a generic site location in New Brunswick (on land or offshore with power transmitted into New Brunswick's grid). In certain cases, some judgments on the energy harvest technology suitable to the available resource were made based on the information available on the nature of the resource in the province.

Performance of the thermal power alternatives were estimated at average ambient conditions and based on seawater once-through cooling. Carbon capture systems and costs of carbon were not included in the initial estimates. The impact of carbon pricing was analyzed separately in Section 10.4 (Sensitivity Analysis).

Capital costs are based on Hatch in-house data from recent similar projects, and on publicly available industry data from conferences, reports, professional papers and other publications. Referenced historical project costs were adjusted for inflation and to 2013 Canadian dollars as needed. Costs associated with construction management, engineering and project management, as well as contingencies, are based on Hatch's own experience.

Project costs include mobilization to the site, procurement and installation of the generating equipment, contingencies, permitting, engineering and management.

For some alternatives, a “Capital Cost Range” to be expected for projects in New Brunswick is provided. It is intended to account for site specific and project definition factors. Renewable power in general is harvested from relatively low energy density resources, and the methods of harvest and associated technology selection are factors contributing to a cost estimate range. The concept of a cost estimate “range” used in this study is not to be confused with estimate “accuracy.” Accuracy is a function of engineering content and can be improved by additional scope definition, site specific data and project cost elements obtained from vendor quotes (as an example).

Capital costs provided by Hatch were expressed as overnight costs and did not account for escalation, overhead costs, owner’s costs or interest during construction. However, NB Power included an interest rate during construction of 5.90 per cent, consistent with public-financed projects. Escalation was also applied to capital projects that reflected the electric utility construction price index, projected at 3.2 per cent per year for new hydro projects and 3.6 per cent per year for all other supply options. These price indices were determined from the Handy Whitman Index of Public Utility Construction Costs. All other costs, including operating and maintenance (O&M) costs were projected to increase at 2 per cent per year. Capital costs also did not include transmission interconnections or upgrade costs since these costs would be site specific. In most cases, overhead costs, owners’ costs and transmission costs would be small in comparison to the project capital costs. Therefore, the effect would be within the relative accuracy of the original estimate, which, as mentioned previously, is an order-of-magnitude estimate.

Typical plant operations and operating modes are described in support of O&M cost estimates. Costs include operators of the facility, maintenance labour and materials, and the administrative costs to provide the facility service, but exclude taxes and royalties, owner’s administrative costs at the corporate level, profit and overhead. All O&M costs presented are first year costs, not levelized costs.

Operating costs do not include fuel costs. However, information is provided on typical heat rates for each thermal power technology. Operating costs may also include a provision for major capital renewals expressed in terms of cost per kW, per year. The present value of the expected capital renewal expense was used to derive these estimates.

6.2. Community and Personal Distributed Generation

While the traditional planning approach for utilities has been to perform least cost planning using traditional utility supply options, we now must consider what part communities and individual customers play in the development of the plan.

This section addresses opportunities for harnessing New Brunswick’s natural resources in renewable energy. A recap of the potential supply-side options for distributed generation is provided. In addition, a discussion about programs enabling community-distributed generation is provided as well as customers personal distributed generation options that will be available in the future.

Existing Program Support

The government of New Brunswick and NB Power have a variety of programs that encourage community distributed generation. These programs spur decentralized generation and broad geographical distribution of renewable energy sources.

The following is a brief description of New Brunswick's community-distributed generation opportunities that include:

- Net Metering
- Embedded Generation program
- Community Energy Program (currently under development), and
- Customer Personalized Distributed Generation Options

The supply options available for these distributed-generation programs can include:

- Small Hydro (see 4.2.1 for additional information)
- Biomass (see 4.2.4.1 for additional information)
- Small Wind of up to approximately 10 MW (see 4.2.2 for additional information), and
- Solar Photovoltaic (see 4.2.7 for additional information)

NB Power promotes regionally distributed generation through power purchase agreements. Historically, these agreements have been procured through a Request for Proposal (RFP) process. The electricity produced from these programs allow NB Power to meet its renewable electricity targets.

Net Metering

NB Power has a net metering program that allows customers to produce their own renewable energy by connecting a generation unit of less than 100 KW to NB Power's distribution system. In order to qualify for this program, the generation units must come from renewable energy sources compatible with Environment Canada's Environmental Choice Program[14] and Ecologo Certification[15], and standards for renewable low-impact electricity products such as biogas, biomass, solar, small hydro or wind.

A special net meter records the electricity NB Power delivers to the customer and the electricity NB Power receives back from the customer's generation unit. The customer is then billed for any net amount of electricity consumed and receives a credit for power sold into the grid. Any credits unused during the current billing period are carried forward to subsequent billing

[14] http://www.ec.gc.ca/energie-energy/default.asp?lang=En&n=4F903768-1
[15] http://www.ecologo.org/common/assets/criterias/CCD-003.pdf

periods until March 31 of each year, after which credits are reduced to zero. This enables the customer to offset some of their consumption by generating their own power. However, because of its limit of 100 KW, the net metering program is generally of interest to residential and small commercial operations only.

Embedded Generation

The Embedded Generation program allows potential developers or independent power producers to connect their environmentally sustainable generation to NB Power's 12 kV distribution system. Typical embedded generators may include landfills, biogas, biomass as well as solar, wind, hydro, and ocean technologies.

The embedded generation facility may range in size from 100 kW to 3,000 kW. However, certain areas of the distribution system are more limited than others to accept the higher capacity and the generation output may be restricted in certain areas of the province. The initial allocation for these programs is currently set at 20,000 kW (20 MW).

The embedded generation program is unlike the net metering program because the energy output of the independent power producer is not used to offset their existing electricity consumption. Rather, NB Power purchases the renewable energy and environmental attributes at an established Feed-in tariff.

The Feed-in tariff is designed to make it easier for the independent power producer to sell their electricity to NB Power at a fixed and stable price under a long-term contract. The Feed-in tariff effective October 1, 2016 is $0.10457 per kWh. This is based on the cost of electricity supplied from the distribution system.

NB Power understands that there is a growing appetite in New Brunswick for sustainable, renewable energy projects. The Embedded Generation Program supports these projects by allowing these small-scale, locally owned generators to connect to our distribution system and to supply renewable energy onto the grid. This IRP has assumed 13 MW of Embedded Generation will be added by 2020 to fulfill the total allocation of 20 MW.

Community Energy Program

NB Power has assumed the development of energy resources from local small-scale projects would occur as part of the Government of New Brunswick's Locally Owned Renewable Energy Projects that are Small Scale (LORESS) regulations. This regulation can be found on the Government of New Brunswick's website[16]. The LORESS program will:

1. support local First Nations small-scale renewable projects
2. integrate current and future renewable generation in the most cost-effective and efficient manner, and

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[16] http://laws.gnb.ca/en/ShowPdf/cr/2015-60.pdf

3. support promising solar, bio-energy and other emerging renewable energy technologies

This IRP has assumed a phased in approach of this development so that by 2020, 80 MW (approximately 300 GWh) of incremental new renewable generation will be added to the system. To manage the integration of this development with the system, NB Power will focus on projects that provide dispatch flexibility and can integrate with NB Power's smart grid initiative.

Customer Personalized Distributed Generation Options

As part of NB Power future planning, consideration will be made to reflect customers desire to produce and store electricity for their own consumption and also have the flexibility to remain connected to the grid and to potentially contribute their surplus electricity to the grid.

As part of the consultation process for this IRP, focus was given to what matters most for customers, and for customers to share their thoughts, connect ideas, listen to understand, and encourage participation. These discussions reinforced two high level priorities:

- Clean Energy
  - customers want NB Power to be a leader in energy efficiency
  - customers support using less fossil fuels and to transition to a cleaner energy future, and
  - New Brunswickers have a responsibility to make changes to help address climate change
- Customer Options
  - Customers are willing to personally invest in equipment and technology to manage their electricity use and costs.

To achieve these priorities it will be important to prepare the landscape for all customers to participate. Energy Smart NB, which is evaluated in this IRP, forms the underpinning by which a new partnership with customers will be established. Over time, new business models will be developed that will introduce new technologies to achieve desired customer values. The investment towards grid modernization will enable customer owned equipment and technology to be plug-and-play and to provide customer visualization, communication and control of this equipment through a hand held device such as a smartphone.

Although the business models are in the early stages of development for customer owned generation options, this IRP has attempted to capture the impact of high penetration of customer owned solar. This analysis was done in Section 10.4 (Sensitivity Analysis).

7. RESULTS OF SUPPLY ANALYSIS

7.1. Levelized Cost of Electricity

The following sections provide a detailed analysis of all supply options included in this IRP. Each supply option was evaluated using the Levelized Cost of Electricity (LCOE) methodology, which is described in greater detail in the next section. This is an important step in the IRP process because it allows the system planner to rank and choose the appropriate supply option candidates from the larger portfolio of options.

The analysis provides the total accounting life cost comparison of each project, which is expressed as an equivalent electricity price in dollars per megawatt hour ($ per MWh). The full accounting life cycle costs include capital, operating and maintenance (O&M), fuel and environmental costs. In this analysis, the levelized electricity prices were expressed in 2013 dollars so that they could be easily compared to NB Power's current costs of electricity generation.

7.1.1. Levelized Cost of Electricity Methodology

The LCOE methodology is the economic assessment of the cost of the energy/generating option. It includes all of the costs over its lifetime, namely:

- initial investment
- OM&A
- cost of fuel (if applicable)
- cost of capital that includes interest and return on equity (if applicable)
- environmental costs (if applicable), and
- taxes (if applicable)

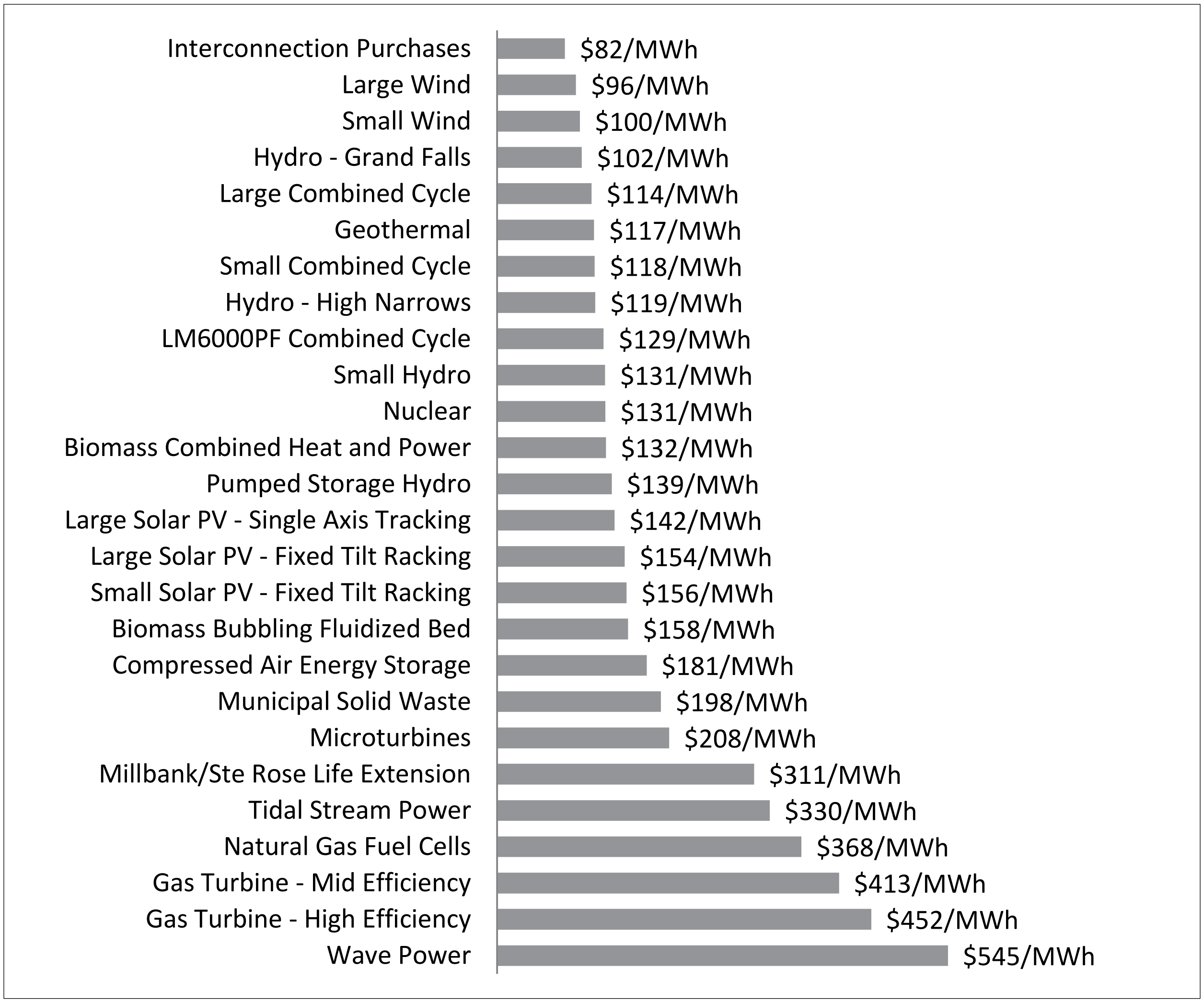
The LCOE is the present value of the total cost stream of all the items listed above for a given generation option over its economic life to generate electricity. It was used to evaluate and compare the relative economics of each potential generation option. The LCOE is essentially the minimum price at which energy must be sold for an energy project to break even over the life of the project.

No financial risks associated with future construction prices or operating risks were included in the LCOE analysis. This was left to production cost modelling and sensitivity analyses. Also, it is important to note that the supply options considered in this IRP are of various sizes, fuel types, and varying levels of reliability. The latter is of particular importance because extra costs may be required to ensure an intermittent or variable supply option (such as wind, solar, wave, and tidal power) is reliable, by providing a backup to that supply option in the event it is not available. The costs presented here are simply the cost of the stand-alone option, or the "sticker price" of that option. However, the LCOE analysis has included the extra costs required for ancillary support such as load following of $10 per MWh. This ancillary cost has been applied to all intermittent options (wind, solar, and wave power).

The full costs of any of the supply options presented here are captured through the production cost modelling phase of the analysis, since the system is dispatched in economic order, and the lowest cost options are selected as needed to meet the load and reserve requirements without the risk of rolling blackouts. It is during the production cost modelling that the appropriate level of backup and the associated cost is included to support any of the intermittent and variable supply option under consideration.

The following chart provides the LCOE and ranking for the supply options assessed in this IRP.

Figure 27 – Levelized cost of electricity



The options presented show a significant variation in electricity prices, from a low of about $80 per MWh to a high of about $550 per MWh. In many cases, the variations were due to the nature of the options and their level of maturity (commercialization). Another influencing factor was the assumed operating hours. Low operating hours of peaking units such as CT's, Millbank and Ste. Rose will tend to increase the LCOE.

The most expensive renewable options are wave power and tidal power, which are well above $300 per MWh. Each of these options is in the very early phases of commercialization; therefore, the expected installation costs are high to account for the many unknowns such as technology choices and regulatory requirements. Although cost reductions are expected as technologies mature, recent trends highlight that high demand could lead to price increases. In this analysis, the projected installed costs of the various options were based on current experiences and costs but were escalated at the construction price index over time.

The supply options presented, and resultant LCOE depicted in the previous chart, were based on applying public funding for capital requirements. Assuming this arrangement, some of the options and resultant LCOE prices could compete with NB Power's existing total system costs of about $80 to $100 per MWh over the near term (of which about $20 per MWh is for distribution).

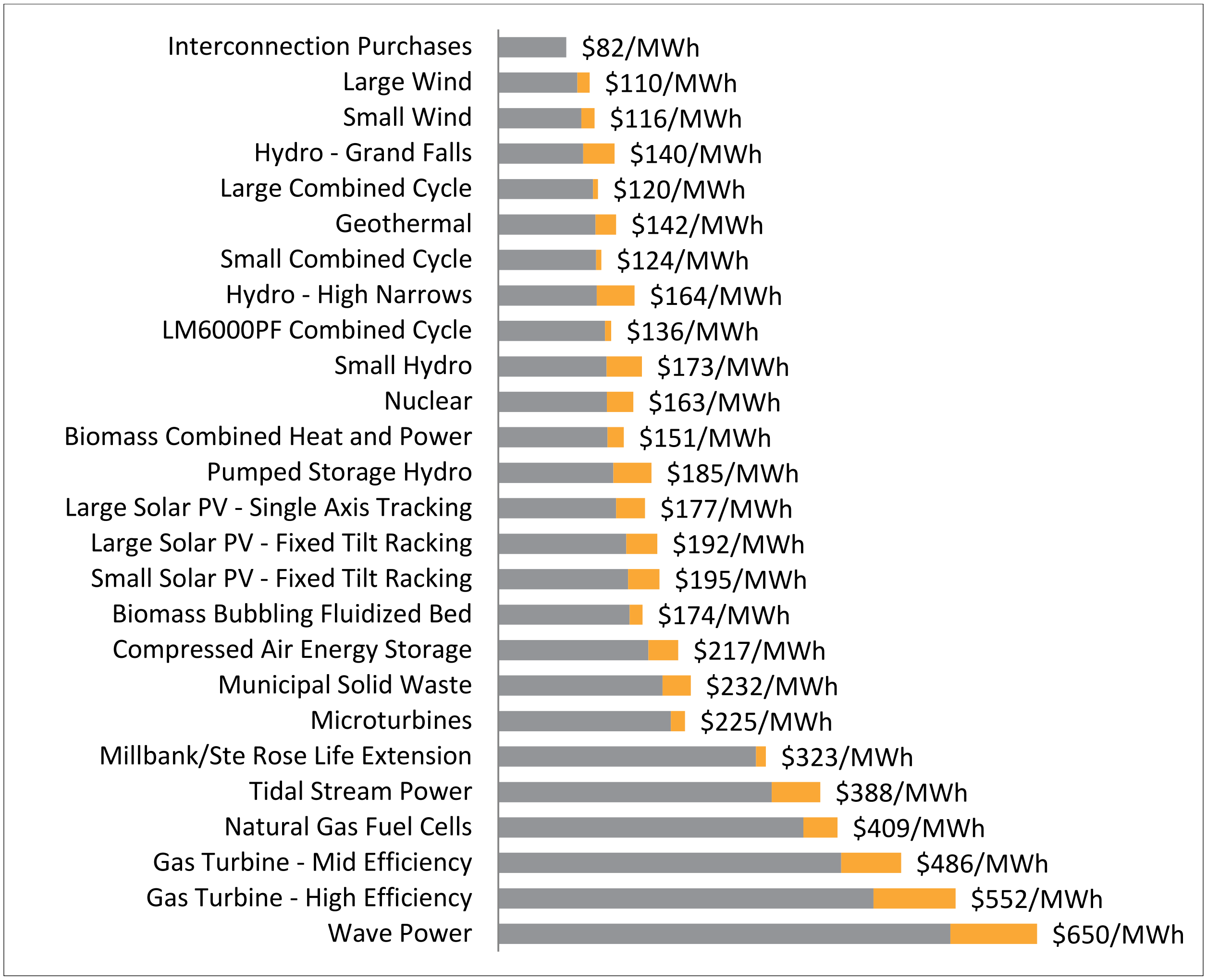
As a final note, the interconnection purchase option does not include capital costs for new transmission that may be required to support this option. Only the cost associated with firm energy and capacity is included for this option.

7.1.2. Private versus Public Financing

As mentioned in Section 5.8.5 (The Weighed Average Cost of Capital), the cost of capital for privately initiated power projects can be inferred from the most current actual experience of some of the major independent power producers (IPP's) located in Canada. Using this knowledge, this study assumed private projects average cost of debt to be 6.5 per cent[17] with an after-tax return on equity of 11 per cent, to which a 60:40 debt-to-equity structure is applied. This produces an after-tax weighted average cost of capital (WACC) of about 7.13 per cent, assuming a composite income tax rate of 30 per cent. Applying these parameters to the supply options tends to increase the LCOE in comparison to publicly financed projects. Figure 28 illustrates the effect of these assumptions.

[17] This assumes a Government of Canada rate of 4.25 per cent plus a 225 basis point spread for private entities with Dominion Bond Rating System (DBRS) rating of BBB-. See Section 5.8.5 (The Weighted Average Cost of Capital)

Figure 28: Levelized cost of electricity including the incremental cost of private financing:



On average, privately financed renewable projects will command a five to 40 per cent increase in electricity prices, depending on the project. On an individual basis, the following average increases in electricity prices are expected from private renewable projects:

- Solar – 20 per cent
- Tidal – 20 per cent
- Wind – 15 per cent
- Hydro – 40 per cent

Fossil generating options such as natural gas vary from about five to 10 per cent, and nuclear will command an increase of approximately 20 per cent. The variability in the incremental prices is mainly due to the cost and weighting of the capital investment versus fuel and O&M. Therefore one would expect that renewable energy projects, as well as nuclear projects, would incur the highest impact because the capital costs make up a larger portion of the total project costs.

7.1.3. Levelized Cost of Electricity Summary

Based on the LCOE analysis and the load and resource assessment performed previously, it is possible to formulate alternative system plans that can be evaluated in detail through production cost and financial modelling. All plans require options to address the current Renewable Portfolio Standard (RPS) requirements in the near term, as well as capital stock turnover in the longer term. The options required are a mix of base load and peaking requirements. In addition, the screening criterion has applied a price cap of $150 per MWh. This means that options with LCOE prices above this value would be culled. This criterion is selected to manage the number of options available to the Strategist model, which was used for production cost modelling. This model is explained in greater detail in Section 10 (Integrated Demand and Supply).

Based on this screening criterion, the following options have been selected for further evaluation:

- Interconnection Purchases
- Wind
- Hydro - Grand Falls
- Natural Gas Combined Cycle
- Enhanced Geothermal
- Hydro – High Narrows
- Small Hydro
- Nuclear
- Biomass Combined Heat and Power, and
- Large Solar PV – Single Axis Tracking

In addition, the following peaking options were selected for further evaluation:

- Simple Cycle Gas Turbines – Mid-Efficiency, and
- Millbank / Ste. Rose

7.2. Supply-Side Plan Evaluation

Expansion plan optimization analysis models the existing system as well as expansion options. It provides a total net present value cost as a key output for each expansion plan. The goal of supply-side evaluation is to find the least cost and environmentally acceptable supply plan that will reliably meet the electricity needs of New Brunswick.

At this point of the evaluation, particular focus is given in Step 6 of the IRP process shown in Figure 29.

Figure 29: IRP Process

In developing the reference supply plan, all reasonable and feasible alternatives identified in the supply-side screening analysis described in Section 7.1 (Levelized Cost of Electricity) were provided as input and run through PROVIEW to find the least-cost supply plan to reliably meet the forecast future requirement of load and reserve within New Brunswick, with consideration of the RPS requirement of 40 per cent by 2020. PROVIEW is part of the Strategist suite of models developed by Ventyx Inc. of Atlanta, Georgia, to evaluate long-term resource plans. The PROVIEW model has been used by NB Power in developing previous IRPs and is used widely in the electricity industry. It has been reviewed and accepted by the New Brunswick Energy and Utilities Board (EUB).

PROVIEW produces thousands of combinations and permutations using dynamic programming techniques, and ranks the resulting expansion plans in order of increasing costs.

Using the PROVIEW model, system planners were able to study the expansion plan options in detail. Economic dispatch implications associated with differing seasonal load requirements, limited hydro plant energies and storage capability, and environmental constraints were included to determine detailed year-by-year production costs for all plans.

Expansion plan optimization analysis enables a quantifiable comparison of the expansion plans on a cost basis. In addition, comparison can also be made of system energy production, fuel usage, as well as emissions for each of the expansion plans. The flexibility of this modelling capability is not just used to determine a least-cost plan; it is also used to determine the plan's sensitivity and robustness to potential changes in different variables.

In summary, the process for supply-side expansion plan evaluation includes:

- Determining the lowest-cost supply expansion plan using basic assumptions
- Calculating generation mix and GHG emissions, and
- Completing sensitivity analyses of different variables such as fuel prices

7.2.1. Least-Cost Methodology

The PROVIEW analysis determined the least-cost supply plan that would meet the immediate system needs prior to 2027 and in the longer term, to address the aging NB Power generation fleet. The results are shown in Figure 30.

Consideration was also given to the least-cost plan that achieves the Renewable Portfolio Standard (RPS) under the *Electricity Act*. The RPS requires 40 per cent of NB Power in-province energy sales be obtained from renewable resources by 2020. The RPS requirement is a legal obligation for NB Power. The least-cost plan, including RPS, will be used as the Supply Plan.

Figure 30: Summary of least-cost supply plan

FY Ending	Supply Plan	Scheduled Retirements
2018		
2019		
2020	Embedded Generation (13 MW)	
2021	LORESS (80 MW)	
…		
2025		Grandview (-95 MW)
2026		Grand Manan (-26 MW)
2027	NGCC (412 MW)	Bayside (-277 MW)
…		
2031	Millbank / Ste Rose (4 x 99 MW)	Millbank / Ste Rose (-496 MW)
2032		
2033	Mactaquac Life Achievement	
…		
2040	Lepreau Replace-in-kind (660 MW) PUR (175 MW)	Point Lepreau (-660 MW)
2041	NGCC (3 x 412 MW) Millbank /Ste Rose (99 MW)	Belledune (-467 MW) Coleson Cove (-972 MW)
2042		
Total PVRR (2017 $)	**$25.7 B**	

The supply plan includes 80 MW of Community Energy projects and 13 MW of Embedded Generation by 2020. This is to help meet the RPS target by this period. The supply plan also shows major development in the period between 2027 and 2042 to respond to existing facilities' end-of-life schedules. The total present value of revenue requirement (PVRR) shown, is expressed in 2017 Canadian dollars and includes all costs (total fuel and purchased power, new and existing O&M and new and existing capital requirements, as well as total costs for transmission, distribution, products and services, and head office). These costs were captured within the study period as defined between 2017/18 and 2041/42. Inherent in the PVRR are the revenues associated with export sales of electricity and sales associated with products and services (such as water heater rentals and dusk to dawn lighting). These activities tend to reduce the total revenue requirement which translates to lowering rates.

The development of the least-cost supply plan was based solely on meeting in-province electricity requirements plus any long term contractual obligations. The benefits associated with exporting surplus electricity were captured after this process was complete. This allowed the surplus electricity to be made available for export and to capture potential benefits that then reduced the total present value of revenue requirements.

It is noteworthy that the least-cost plan selects a natural gas combined cycle (NGCC) as the first new supply requirement to meet peak demand. This facility will require a long term supply of natural gas. It is assumed the source of supply for natural gas would be available at the prices assumed in this analysis – see Section 5.7 (Fuel Price Forecast). The plan also shows several combustion turbines (CTs) and life extension of Millbank and Ste. Rose to meet peak load requirements. In addition to this, and to respond to the retirement of Point Lepreau, Belledune and Coleson Cove at the end of the period, it is assumed that Point Lepreau would be replaced in kind to maintain 75 per cent non-emitting resources in the long term and that a combination of natural gas generation and interconnection purchases would be required to continue to meet load obligations. It is recognized that a significant investment will be needed in the latter period of the plan. NB Power will look for opportunities and options to separate and spread this investment as this critical period approaches. Finally, it is assumed in this assessment that Mactaquac will undergo life achievement investment that will ensure the station can operate to its intended 100-year lifespan with a modified approach to maintenance and adjusting and replacing equipment over time and that the capacity from this facility will be fully available by 2033. This assumption follows three years of expert research, including input from science, engineers, the public and First Nations.

8. ENERGY EFFICIENCY, DEMAND MANAGEMENT AND SMART GRID

8.1. Demand-Side Management

An important part of the integrated resource planning process is recognizing that conservation, energy efficiency and load demand management, also referred to as demand-side management, is a potential low-cost alternative to developing new power plants. Demand management is any attempt to change or influence the demand placed upon the system by the customer. It encompasses a broad range of techniques from the direct control of customer equipment to educating customers about conserving electricity.

Figure 31 outlines the overall IRP study process. This section of the report outlines the detailed procedures employed in evaluating the demand-side options portion of Step 5 shown in Figure 31. As in the supply-side evaluation, Step 6 is also used to assess the effectiveness of demand-side management.

Refer to Section 2.2 (The IRP Process) for additional information.

Figure 31: IRP Process

Although North American utilities have recognized the value of energy efficiency and demand management since the 1960s, management of demand side did not start until a decade later. In the early 1970s, inflation, environmental concerns and escalating fuel prices began to have significant effects on energy costs. In 1973, the Organization of Petroleum Exporting Countries (OPEC) shocked the world with an oil embargo. The high inflation that resulted caused the cost of electricity from new power plants to be as much as 10 times higher than that generated at existing plants. More focus was then given to energy efficiency and demand management in 1978 when the Public Utility Regulatory Policies Act (PURPA) was enacted in the United States. This Act was passed as part of the National Energy Act and was meant to promote energy conservation (reduce demand) and promote greater use of domestic energy and renewable energy (increase supply). This Act started the industry towards deregulation in which an open competitive market for bulk electricity supply was created along with the inclusion of an open non-discriminatory transmission system. The electricity industry in North America since 1978 has moved from what was once comprised predominately of vertically integrated monopolies to a fragmented industry comprised of separate generation and transmission companies as well as local distribution companies under various jurisdictional regulatory rules.

Since 1978 and PURPA, utility planners were motivated by the vision of a sustainable energy future. They increased their focus on potential achievable conservation, energy efficiency and load demand management in conjunction with traditional generation alternatives to limit:

- negative effects on the environment
- the financial impact of fossil fuel prices, and
- future rate increases to customers

The combination of supply-side and demand management options which incur the lowest costs, consistent with other important goals, has become known as least-cost, integrated resource planning and is actively used by many utilities, including NB Power.

Prior to this plan, NB Power completed four internal IRPs: in 1990, 1995, 2002 and 2010. In addition, the first public IRP was completed in 2014. During the time of internal IRP’s, NB Power was involved in several demand management studies conducted by the New Brunswick Department of Energy.

8.2. Energy Smart NB

Energy efficiency and conservation is an integral part of a plan that NB Power continues to pursue to reduce and shift demand. This approach called Energy Smart NB is designed to provide benefit to the participating customers through direct savings on their power bills and to introduce new technologies that can be leveraged to help customers further manage their electricity consumption. This approach also provides a benefit to NB Power through immediate fuel cost savings and through lower capital requirements in the long term by reducing the need for new supply in the future. This, then, provides indirect benefit to all customers by ensuring low and stable rates.

Taken in its entirety, Energy Smart NB is a long-range, foundational strategy meant to transform the way NB Power operates while introducing a wide range of new customer benefits. Indeed, it is widely acknowledged that the electric utility industry is changing, and utilities must change along with it to meet their customers' needs. A 2017 report issued by Utility Dive, an industry news and analysis firm, shows that nearly all of 600 North American industry executives surveyed believe utilities must make fundamental changes to the way they have operated for the past 100 years[18]. "Electrical utilities are incumbent players in a century-old industry dealing with disruption driven by new technologies, regulations and market realities," state the authors.

In New Brunswick, the need for change is driven by the emergence of advanced technologies, changing customer preferences, and new energy economics. A key issue faced by NB Power is its projection that, starting in 2027, it will require new supply to meet customer demands. Instead of investing in new generation assets and/or power purchase agreements, NB Power is proposing to lower demand by investing in demand-side techniques and technologies.

Another driver is that energy use throughout the Province is highly seasonal and swings significantly within any given day. The winter peak load is double the summer peak load and in any day the load requirements may shift by 400 and 600 megawatts, requiring a plant of this size to be available for as little as one hour. This contributes to low generation utilization—averaging less than 50 percent which then can have a direct impact on electricity rates. Advances in technology provide opportunities to leverage this unused capacity, and those opportunities become even more compelling when customers become more knowledgeable and proactive energy consumers.

At the same time, many components of the electricity grid are decades old and in need of updating. New "smart" technologies are available that can improve the efficiency, flexibility and reliability of the grid while enabling important new benefits. By modernizing the grid, NB Power can better understand how and when energy is being consumed and use that information to operate more efficiently and provide customers with better service, new energy-saving products and services, and more flexible rate plans. It is important to note that the New Brunswick Energy and Utilities Board has directed NB Power to improve its cost of service studies to explore more options for time-sensitive pricing.

[18] 2017 State of the Electric Utility Survey Report, retrieved from http://www.utilitydive.com/library/2017-state-of-the-electric-utility-survey-report/.

In addition, grid modernization lays the foundation for a wide range of reliability benefits, including more efficient outage response, which can greatly aid in storm restoration, and enhanced ability to detect and correct issues on the grid before they affect customers.

Smart grid is also essential to the expansion of renewable and distributed energy sources. As more variable energy sources are connected to the grid, however, utilities face greater challenges in managing that variability to balance supply and demand while maintaining the stability of the grid. By building smart technologies into the grid, utilities can support greater customer participation in renewables while also improving reliability and efficiency—and offer customers more choice, control, and convenience in other ways as well.

Clearly, Energy Smart NB is a far-reaching initiative that touches virtually every function within the utility. That's why the initiative also includes extensive process changes and a sharp focus on improving business capabilities.

Major Elements of Energy Smart NB

Energy Smart NB consists of operational initiatives, enabling technology, and business process improvements. Enabling technology and business process improvements are required for implementation and success of the operational initiatives. Energy Smart NB has three main interrelated elements:

Smart Grid:

Grid modernization technology and software, including engineering and design work, along with the internal process changes and enhanced business capabilities required to implement and optimize the technology. This includes technologies such as Advanced Metering Infrastructure and Integrated Load Management that will enable NB Power to support the goal of reducing and shifting demand while laying the foundation for a wide range of additional benefits, including improved grid reliability and security, supporting the expansion of renewable and distributed energy sources, and providing customers with more choice, control, and convenience.

Smart Habits:

Energy efficiency and demand response programs that help customers reduce and/or shift their energy usage without compromising the overall value of electricity service. These include home insulation programs, a commercial building retrofit program, the Smart Habits product rebate program, and residential and commercial lighting programs. Demand response programs include smart hot water heaters, smart thermostats and the "beat the peak" education program.

Smart Solutions:

New products and services that leverage both DSM initiatives and smart grid technology to engage consumers as active participants in managing their electricity usage. Specific initiatives included in the new products and services program include the LED dusk to dawn program, the hot water heater rental program, the LED street light program, and in the future, home energy generation such as solar, battery storage, electric vehicle charging and time-of-use rates.

These three elements of Energy Smart NB are interdependent. The grid modernization efforts comprise the foundation enabling infrastructure of Energy Smart NB—the enabling investments. This infrastructure drives development of efficiency and demand response programs, and development of products and services that drive the revenue programs and operational improvements in the field. In turn, the efficiency and demand response programs, the revenue programs, and the operational improvements drive customer benefits, which include lower costs and higher quality service compared to a future where Energy Smart NB were not in place. Therefore, Energy Smart NB can be regarded in its entirety as a unified set of initiatives.

The following sections provide a short description of the programs and activities stemming from the Energy Smart NB plan. A balanced approach was taken in determining the areas of investments in order to capture cost-effective electricity efficiency measures across the sectors and to address new, innovative energy technologies and strategies. Based on sound management practices, the plan will be revisited on a regular basis by assessing program results and market conditions and by seizing new opportunities that may arise.

8.2.1. DSM Plan 2019 to 2021

It is important to stress demand-side management (DSM) resources, such as energy efficiency and demand response programs, can play a pivotal role in meeting New Brunswick's future power needs. These programs are foundational to the Energy Smart NB plan. Previous IRP's have shown that DSM provides benefit to both utility and customers and help to keep rates lower in the long term. The benefits are derived from avoided generation and capacity costs and higher overall efficiency. To participating customers, DSM lowers energy consumption and bills. This also has a direct benefit to the environment, through lower emissions.

The three year DSM plan focuses on two categories of initiatives, aimed at reducing both energy and peak capacity needs:

Energy efficiency
Refers to initiatives that are focused on reducing loads, whether through more energy efficient technologies (e.g. efficient equipment, lighting, motors, and building envelopes) or through energy-conserving behaviour (e.g. switching off lights when leaving a room). While focused on energy savings, it is noteworthy that energy efficiency typically generates both energy and peak capacity savings.

Demand response
refers to initiatives that are focused on shifting loads, whether through more peak-efficient technologies (e.g. three-element water heaters that distribute loads more evenly), customer-

driven actions (e.g. responding to price signals by programming a dishwasher to launch outside of peak hours), or through NB Power-driven actions (e.g. controlling smart water heaters during the critical hours of the system). With some exceptions, demand response typically generates only capacity savings.

NB Power's first DSM Plan was issued in December 2015 and filed with the Energy and Utilities Board. In it, NB Power proposed a portfolio of EE and DR initiatives—from incentives to direct installations and pilots—for the 2015/16 to 2017/18 timeframe along with enabling activities. The reductions achieved since the 2014 IRP are summarized below:

Figure 32: Historical Achieved Energy and Demand Savings

FY Ending	MW	GWh
2015	5	8
2016	9	34
2017	16	79

The three year DSM plan has been refreshed for this IRP and includes a detailed description of pilots and programs that include program priorities to achieve energy savings, cost effectiveness, and investments. This is done for three key strategic areas that include the residential sector, commercial and industrial sectors and an enabling strategy that include the activities and investment to drive program development.

In addition, the plan includes a cost-effectiveness analysis for each program, relying on the Program Administrator Cost (PAC) test. Also, an evaluation, measurement and verification (EM&V) plan for the portfolio of programs is developed.

8.2.2. Beyond the First Three Years

The three-year DSM plan was developed from a long-term view that determined approximately 600 MW of capacity and approximately 2 TWh of energy reductions are available. This plan puts NB Power—and all of New Brunswick—on the path to achieving these reductions. The analysis and research used to develop the three-year DSM plan, was used to inform the longer-term costs of the programs used in the integration process.

As mentioned, the deployment of smart grid technology plays an important role to enable and enhance many of the programs required to achieve the capacity and energy reductions described above. Smart grid is part of grid modernization and will contribute to the increased integration of renewable resources, both centrally and as distribution generation, and to the increased efficiency of the grid operations.

In combination, energy efficiency (reduce) and demand reduction (shifting) are foundational to Energy Smart NB. Energy Smart NB includes all costs to implement energy efficiency and demand reduction programs as well as infrastructure costs for smart grid implementation and new product and service offerings to customers. The total cost of Energy Smart NB is projected to be in the order of $1.3 billion on a present value cost basis over the 25 year study period.

The following reductions in electricity requirements are expected from this investment over the next 25 years.

Figure 33: Potential Energy Smart NB reduction schedule

Year	MW	GWh
1	12	55
2	33	131
3	59	215
4	90	310
5	140	459
…		
25	621	2,301

Note that these reductions are incremental to the reductions achieved since the 2014 IRP, previously shown in Figure 32.

9. COMMUNITY DIALOG SESSIONS

9.1. Overview of Public Consultation Process – Our Energy Future NB

Section 100 of the *Electricity Act*, passed October 1, 2013, obliges NB Power to submit an Integrated Resource Plan (IRP) to the Energy and Utilities Board (EUB) as part of the utility's long-term planning process. The Act also obliges NB Power to include "a description of the stakeholder consultations carried out by the Corporation in developing the integrated resource plan."

To achieve the objectives set out in the legislation, and to achieve NB Power's own goals of improved transparency regarding our planning process, and improved energy literacy among our customers and stakeholders, NB Power carried out a broad multi-platform engagement approach with a wide variety of New Brunswickers that included an online survey, facilitated meetings and presentations. This program was called "Our Energy Future NB". A full report on findings and input can be found in Appendix 1 (IRP Public Engagement Program – What Was Said Final Report).

As the planning period of the Integrated Resource Plan is 25 years, it was important to gain a deeper understanding of what's important to customers as they consider New Brunswick's electricity future, and the role they're willing to play to achieve those objectives.

Customer engagement on the Integrated Resource Plan (IRP) was carried out between March 12, 2017 and May 15, 2017. The design of the engagement process was a collaborative effort between the NB Power team and NATIONAL, a communications services firm, with survey design and data analysis services provided by Thinkwell Research.

The goal of the program was to gather values-based input from New Brunswickers about the province's electricity future to inform NB Power's 2017 Integrated Resource Plan. The objectives of the program were to:

- gain a deeper understanding of what is most important to customers as they consider the province's energy future, and the role they're willing to play to achieve those objectives
- gain a deeper understanding of what is most important to customers as they consider the province's energy future, and the role they're willing to play to achieve those objectives
- provide sufficient and appropriate contextual information, in an easy to understand format, about the province's energy landscape, the scope of the IRP process, and what can be influenced

- host a values-based engagement process in person and online that allows New Brunswickers to contribute based on their own perspective, experience, ideas, and what is most important to them, and
- be transparent in sharing what emerges from the consultation effort

9.2. Scope of Engagement

The engagement program consisted of an online survey hosted on the website OurEnergyFutureNB.ca and customer engagement sessions hosted in Fredericton, Moncton, and Beresford.

Efforts to raise awareness of the engagement process and to invite customer participation were extended through: newspaper advertising, social media advertisements (Facebook, Twitter, and YouTube), media relations, direct invitations to stakeholders, and via NB Power's own communications channels (e.g. website, social media).

Input was gathered from 1,221 New Brunswickers online and 52 people who attended engagement sessions. Formal submissions to the process were also received from 3 stakeholder organizations.

Online engagement approach
The online engagement experience was designed with a general public audience in mind. Content was developed to be concise and used plain language. An informational video was produced to provide context for the discussion and the questions posed.

The survey was short and the questions direct. It explored the following topics:

- Affordability
- Clean Energy
- Customer Options

Participants were also provided with an open-ended opportunity to share additional information regarding what was important to them, and those qualitative inputs were coded into conceptually meaningful categories and quantified with NB Power.

In-person engagement approach
The customer engagement sessions were hosted in a world café format.

Representatives of the NB Power executive team served as hosts, and a presentation by Michael Bourque, Director of Integrated Resource Planning provided important context for the discussion. That presentation consisted of: an overview of the IRP, the current situation, outcomes of the 2014 IRP process, possible options for the future, and the increased role customers might play.

Participants were facilitated through an exploration of the following three questions:

1) When considering New Brunswick's electricity future, what's most important to you?
2) What do we need to be successful in advancing these priorities?
3) What can customers do to help advance these priorities?

9.3. Online Engagement Findings

Summary

The results of the online survey indicate that clean energy and affordable rates are both high priorities among New Brunswickers who participated. Respondents mostly agreed with statements related to these two considerations.

The one exception is that there was less agreement overall with the statement 'I am personally willing to pay more for clean energy' than other statements on this topic. This suggests that at least for some, there are limits to the degree to which they want NB Power to embrace this approach.

There were also some clear age divides on several questions. younger respondents (under the age of 35) expressed higher and more intense levels of agreement with statements that endorse clean energy, while older (55+) respondents did the same for statements that related to managing costs (keeping rates as low as possible, investing in options to allow them to better manage their energy use, etc.).

This should not be interpreted as meaning that younger respondents do not favour low rates, or that older respondents do not support clean energy. It does mean, however, that the age groups are more concerned and sensitive to one priority over the other.

The statements New Brunswickers had the highest level of agreement with, were:

- Clean Energy
    - I want NB Power to be a leader in energy efficiency
    - I support using less fossil fuels as we transition to a cleaner energy future to meet out climate change commitments
    - New Brunswickers have a responsibility to make changes to help address climate change

- Customer Options
    - I am willing to personally invest in equipment and technology to manage my electricity use and costs (e.g. insulation, programmable thermostats)

The single largest group of respondents of the survey came from the middle age (35-54) category, at 45 per cent. The proportion of younger (under 35) and older (55+) respondents was relatively equal (25 per cent and 27 per cent respectively).
Respondents were also provided with an opportunity to indicate how much of a priority they place on four priorities for NB Power, out of a possible 100 points. The highest 'weight' was assigned to clean energy (36.1 average), followed very closely by the lowest rates (32.8). Customer options (16.5) and debt repayment (14.5) were not rated as strongly.

Respondents from Maliseet and Mi'kmaq communities consistently articulated clean energy as a high priority, and the ability to generate power for sale back to the grid.

First Nations community representatives identified the following priorities during the Beresford engagement session:

- Inclusion of First Nations
- More green Energy
- Affordability
- The Environment
- Need for development in the North
- Opening markets
- Lower or eliminate carbon emissions
- Grants or incentives for wind/solar energy development

9.4. Customer Engagement Session Findings

Summary

Customers had deep discussions during the engagement sessions about their priorities when considering New Brunswick's energy future and what was most important to them. The general themes are reflected below.

More detailed information and findings related to the IRP public engagement program can be found in a document called "What Was Said Final Report" which can be found in Appendix 1 (IRP Public Engagement Program – What Was Said Final Report).

10. INTEGRATED DEMAND AND SUPPLY

10.1. Introduction

To best develop a least-cost expansion plan, neither the supply-side nor the demand-side analysis results can be used in isolation. One of the major components of least-cost planning is the integration of energy efficiency, demand response and smart grid programs sometimes referred to in combination as demand side management (DSM) programs. These programs are foundational to Energy Smart NB and are evaluated as an alternative to power plants in this IRP. The results of the supply-side analysis can now be used as a supply reference plan for DSM integration wherein this program has the opportunity to defer or displace a supply-side unit, based on competing economics of the DSM measure(s) and the generating unit(s).

The first step in this integration process was a preliminary economic screening of the DSM measures under consideration. During this screening, certain simplifying assumptions about DSM options and their interactions with supply-side generating plants were made in order to screen out only those measures which were obviously not cost effective and therefore did not need to be subjected to more detailed analysis. The screening analysis assumed that avoided capacity and energy costs could be calculated by using combustion turbines for peaking needs identified in this plan as required beginning in 2027, and avoided energy costs based on the marginal system costs (fuel, purchased power and variable O&M) that would be displaced by energy reductions.

Another simplifying assumption used in the screening analysis was that any increment of DSM capacity reduction, regardless of diversity, could defer an equivalent amount of supply capacity. In reality, only discrete blocks of supply capacity can be deferred. Therefore, in order for a DSM measure to successfully avoid the need for new capacity, it must be of sufficient size, either by itself or in combination with other economically desirable measures.

In order to properly evaluate the screened-in DSM options, the simplifying assumptions listed above are removed and the DSM program and supply-side options are allowed to compete equally in a detailed and realistic simulation. The PROVIEW dynamic program expansion planning software model was used to evaluate the ability of DSM options to realistically avoid or defer generation requirements. PROVIEW is an automatic expansion-planning model that is used to determine the least-cost balanced demand and supply plan for a utility system under a prescribed set of constraints and assumptions. PROVIEW realistically simulates the operation of a utility system to determine the cost and reliability effects of adding resources to the system or of modifying the load through the DSM program. In this study, the dynamic programming process simulated full capital and production cost effects of thousands of feasible combinations of DSM and supply-side options.

10.2. Integration Approach and Methodology

10.2.1. Supply Assumptions

Based on the results of the supply-side analysis in Section 7.2 (Supply-Side Plan Evaluation), the least-cost supply-side resource plan outlined in Figure 34 was used for the evaluation of Energy Smart NB integration.

Figure 34: Supply Plan

FY Ending	Supply Plan	Scheduled Retirements
2018		
2019		
2020	Embedded Generation (13 MW)	
2021	LORESS (80 MW)	
…		
2025		Grandview (-95 MW)
2026		Grand Manan (-26 MW)
2027	NGCC (412 MW)	Bayside (-277 MW)
…		
2031	Millbank / Ste Rose (4 x 99 MW)	Millbank / Ste Rose (-496 MW)
2032		
2033	Mactaquac Life Achievement	
…		
2040	Lepreau Replace-in-kind (660 MW) PUR (175 MW)	Point Lepreau (-660 MW)
2041	NGCC (3 x 412 MW) Millbank / Ste Rose (99 MW)	Belledune (-467 MW) Coleson Cove (-972 MW)
2042		

It should be noted that the retirements of Point Lepreau (660 MW), Belledune (467 MW) and Coleson Cove (972 MW) in 2039/40 and 2040/41 represent over half of the installed capacity of the system and typically supply over half of the province's electricity requirements. The simultaneous retirement of these plants will pose challenges for NB Power because of the large amount of capital and human resources that will be required to install replacement generation facilities in a short period of time. The resource plan during those years will be refined over the next 15 years, as the plants approach their end of life and consideration of retirement dates and construction schedules factored in. The resource plans that are shown in the following sections are representative of the relative costs and options made available and allow for appropriate comparison across scenarios and the evaluation of the Energy Smart NB option. The final supply plan and replacement schedule will continue to be revised over time.

At this stage, the alternatives in the Supply Plan will now compete with the DSM initiatives contained within the Energy Smart NB option to determine the least-cost mix of supply-side and demand-side options. DSM could defer or completely displace a supply-side resource option during the integration phase. However, the addition of the DSM initiatives obviously would not advance the timing of supply-side addition, nor would DSM cause more power sources to come online than in the Supply Plan. The exception to this would be that resources to meet the RPS requirement (having 40 per cent of New Brunswick's electricity sales come from renewables by 2020) would need to be maintained. This means that the resources such as the 80 MW of community energy under the LORESS program and the 13 MW embedded generation program would be needed to help meet the RPS and therefore would not have an opportunity to be deferred or eliminated with the integration of DSM contained within the Energy Smart NB option.

10.2.2. Demand and Energy Reduction Assumptions from Energy Smart NB

The DSM measures that passed the cost-effective screening, either individually or grouped with similar measures were included in the Energy Smart NB option and offered as an alternative in the PROVIEW optimization. The logical groupings of measures were included within the option according to their nature, operating lives and levelized cost per kW. This was done to reduce the size of the dynamic programming problem within PROVIEW. The total amount of reductions available within the Energy Smart NB option was 621 MW of demand and 2,301 GWh of energy by the end of the study period in 2041/42. Note that these reductions are incremental to the reductions achieved since the 2014 IRP, summarized below:

Figure 35: Historical Achieved Energy and Demand Savings

FY Ending	MW	GWh
2015	5	8
2016	9	34
2017	16	79

For the integration phase of the analysis, NB Power system planners assumed a 25-year schedule for the Energy Smart NB option made available as an expansion plan alternative. This alternative was made available starting in 2017/18 at the earliest, and was allowed to slide, depending on the most economic timing. This was done for two reasons: to simplify the optimization problem and to avoid "over-optimization" of imperfect data estimates. The data used in the screening analyses included best estimates of probable impact and penetration. Also, a projected ramp-up schedule is modelled because Energy Smart NB takes time to implement and to reach its targeted reductions. It also requires continuous commitment to ensure its full impact on the generating system is achieved over a span of many years.

The following schedule of potential demand and energy reductions was established and made available for integration. The cost to implement Energy Smart NB was estimated from the energy efficiency study performed by Dunsky Energy Consulting to develop, implement and administer energy efficiency and demand response programs over the 25-year period, as well as the associated cost to implement NB Power's grid modernization strategy. The total cost of Energy Smart NB was projected to be $1.3 billion on a present value basis over the study period. It was assumed that this cost and the demand and energy reduction potential would continue at a constant level beyond the 25-year program period to represent capital replacement of at least equivalent or greater efficiency. This schedule would then have the flexibility to start anytime during the study period. This configuration was established as outlined in Figure 36.

Figure 36: Potential Energy Smart NB reduction schedule

Year	MW	GWh
1	12	55
2	33	131
3	59	215
4	90	310
5	140	459
…		
25	621	2,301

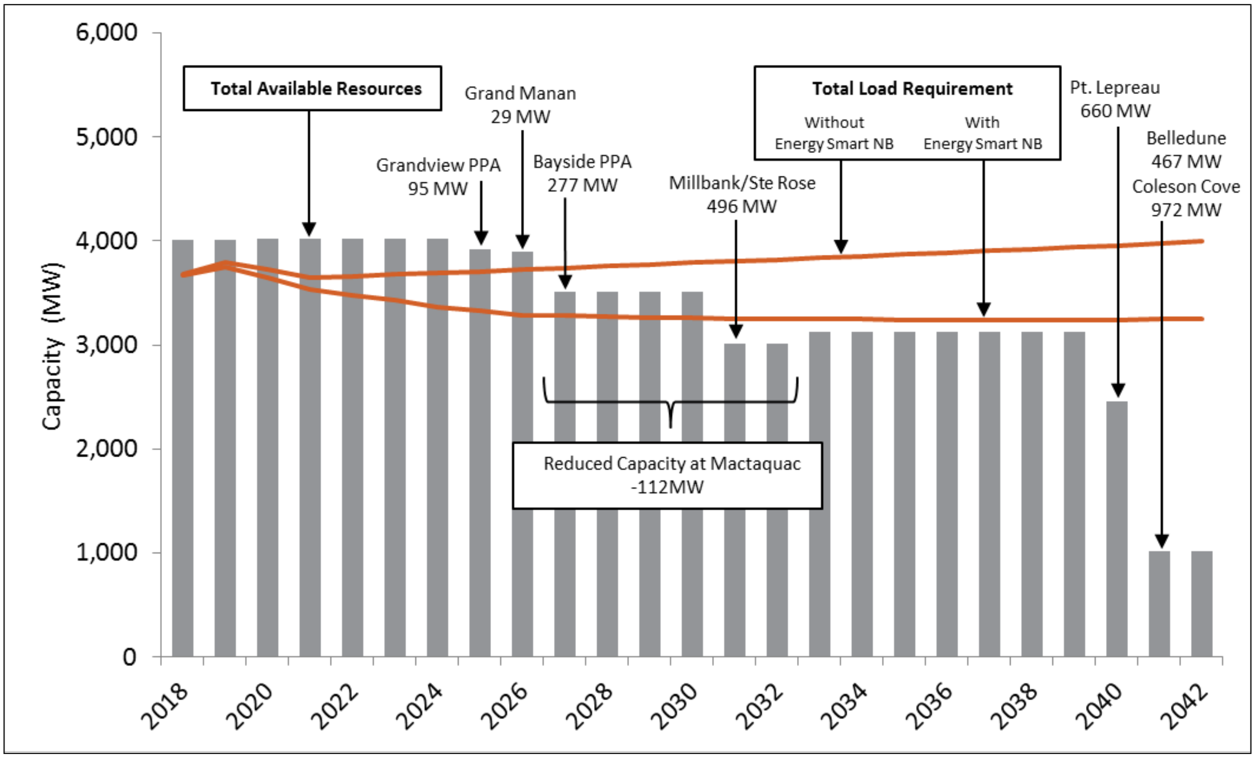
10.2.3. Integration Minimization Criteria

To determine the effect of Energy Smart NB integration on the supply plan analysis, a number of issues were studied. Initially, to examine how the Energy Smart NB compared with the proposed generating units in the supply plan, the dynamic programming module PROVIEW was used to find the least-cost plan in terms of total present value cost. In addition, the least-cost integrated plan was evaluated in terms of average cost of service per kWh or the annual average electricity price required recovering all costs to meet in-province energy requirements. The latter allows for comparison of electricity prices and therefore shows the potential rate impact.

10.3. Final Integration Results

The integration analysis has resulted in the selection of Energy Smart NB early in the study period. The effect on resource requirements is depicted in Figure 37. As expected, this option has deferred the requirement of new capacity.

Figure 37: Effect of including Energy Smart NB on the load and resource requirements



The resulting least-cost integrated plan is outlined in Figure 38. In this plan, Energy Smart NB is included and selected by the PROVIEW model. The load and resource chart in Figure 37 shows new capacity requirement beginning in 2027, but with Energy Smart NB and with the additional capacity added early in the period to meet the RPS requirement, the need for new capacity to meet the new load now has been deferred to 2030/31.

Figure 38: Impact of integrating Energy Smart NB with supply options

FY Ending	Integrated Plan	Supply Plan
2018	Energy Smart NB (621 MW)	
2019		
2020	Embedded Generation (13 MW)	Embedded Generation (13 MW)
2021	LORESS (80 MW)	LORESS (80 MW)
…		
2027		NGCC (412 MW)
…		
2031	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (4 x 99 MW)
2032		
2033	Mactaquac Life Achievement	Mactaquac Life Achievement
…		
2040	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW) PUR (175 MW)
2041	NGCC (3 x 412 MW) Millbank / Ste Rose (2 x 99 MW)	NGCC (3 x 412 MW) Millbank / Ste Rose (99 MW)
2042		
Total PVRR (2017 $)	**$24.6 B**	**$25.7 B**
NPV (2017 $)	**$1.1 B**	

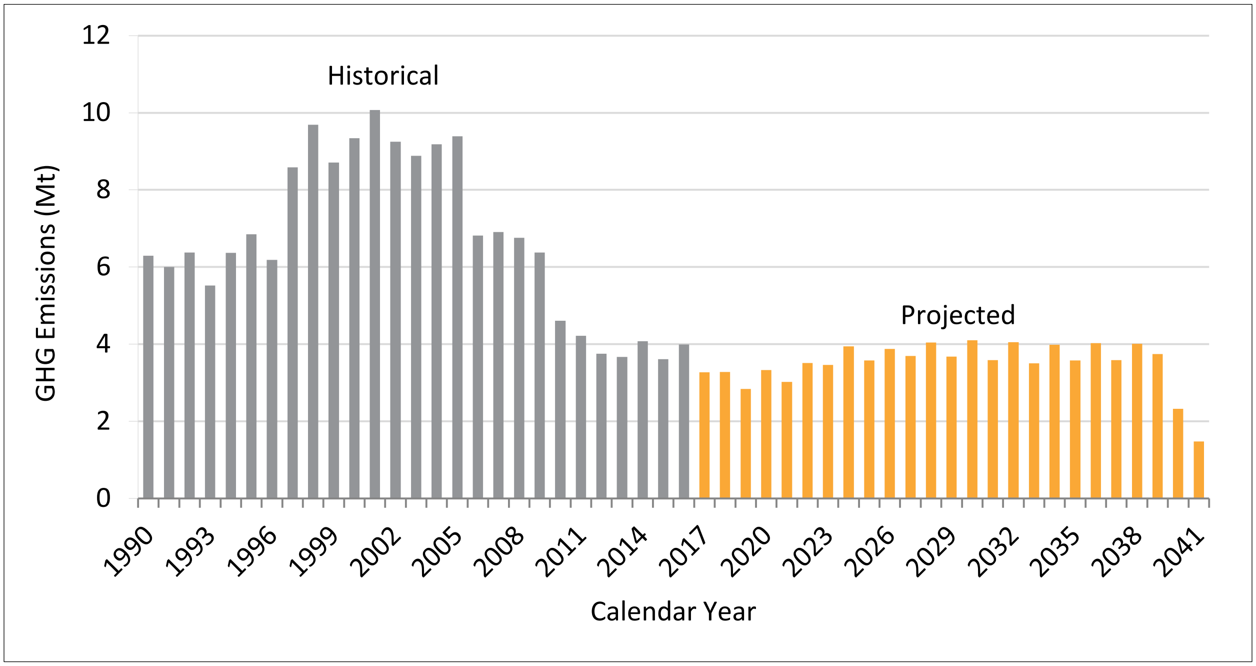
The total present value of revenue requirements (PVRR) shown, are expressed in 2017 Canadian dollars and includes all costs (total fuel and purchased power, new and existing OM&A and new and existing capital requirements, as well as total costs for transmission, distribution, products and services, and head office). These costs were captured within the study period as defined between 2017/18 and 2041/42. Inherent in the PVRR are the revenues associated with export sales of electricity and sales associated with products and services (such as water heater rentals and dusk to dawn lighting). In addition, the Integrated Plan includes the investment associated with Energy Smart NB. This is projected to be $1.3 billion on a present value cost basis over the study period. The projected revenues from products and services that are derived from Energy Smart NB are also included within the PVRR of the Integrated Plan. These activities reduce the total revenue requirement over the study period which translates to lowering rates.

The Integrated Plan's present value of revenue requirements is approximately 4.5 per cent lower than that of the Supply Plan. This represents a net present value (NPV) of $1.1 billion associated with the introduction of Energy Smart NB and is attributable to the deferral or elimination of partial Millbank / Ste Rose life extension, the firm interconnection purchase and a natural gas combined cycle, replacement fuel and purchased power savings as well as other savings associated with grid modernization.

Normally the PROVIEW model will select a resource option when there is a need for new capacity or if there is a need for compliance to meet regulations such as the RPS. The model could also advance a resource option based on economics. The PROVIEW model had the option to add potentially lower cost energy resource options such as a wind energy project as part of the Integrated Plan but chose not to include this option. This option was not cost effective in the Integrated Plan and also not needed to meet the RPS requirement.

The GHG emissions associated with the Integrated Plan is provided in Figure 39 and is compared to historical emissions to serve in-province load.

Figure 39: In-province GHG emissions of the Integrated Plan, compared to actual emissions



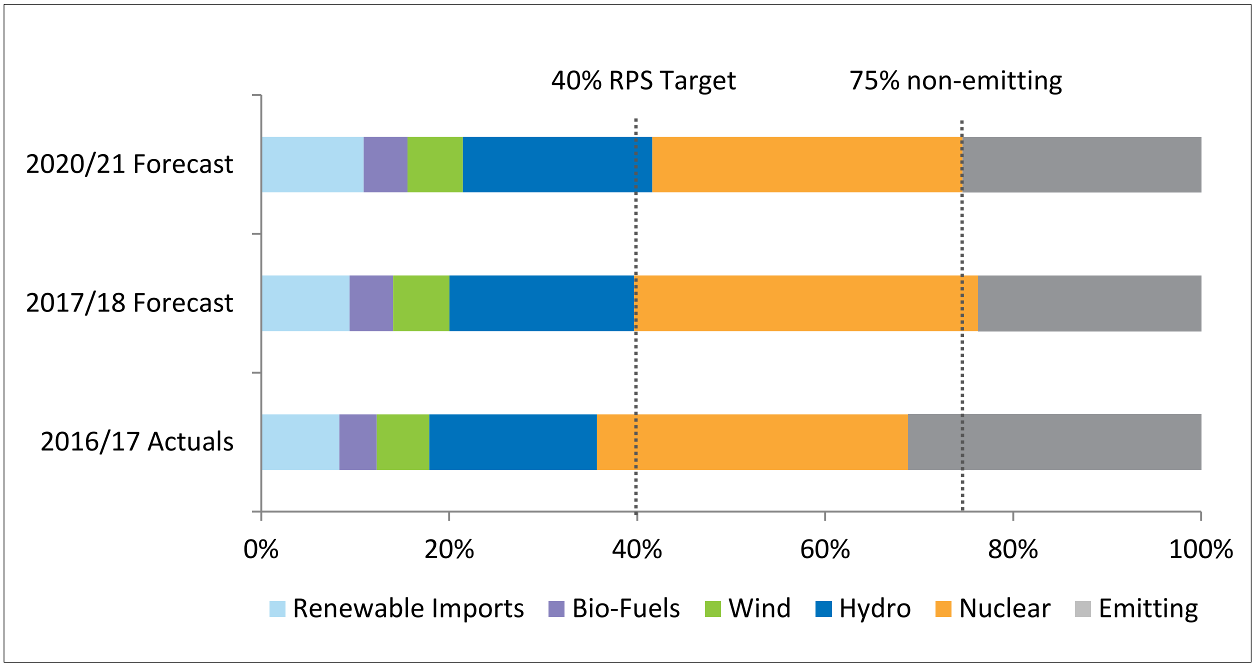
The emissions from the Integrated Plan remain below the 2005 levels and well below long-term historical levels seen in the decade starting in 1990. The emissions shown are associated with serving in-province load as well as emissions attributable to interconnection sales. The emissions associated with natural gas purchased power are also included in the above chart.

The projected emissions starting in 2017 vary slightly on a two-year interval because of the Point Lepreau maintenance outages that occur every second year. The projected emission profile is based on current greenhouse regulation and assumes a cap of 4 Mt over the planning period. Current greenhouse gas regulations are related to coal-fired electricity generation adopted under the Canadian Environmental Protection Act (CEPA), 1999 and apply a performance standard to new coal-fired electricity generation units, and units that have reached the end of their useful life which is defined as 50 years.

In this IRP, NB Power's only coal facility located at Belledune is assumed to be retired in 2041. Although any further regulation related to future greenhouse gas regulation will be included in the next IRP, NB Power has captured the impact of several potential greenhouse regulation scenarios being considered by government. These are presented in Section 10.4 (Sensitivity Analysis) of this report.

NB Power has built its system with consideration of fuel diversity to help reduce the risk and potential exposure to future fuel price fluctuations. In the future, new renewable resources along with the Energy Smart NB plan will improve this diversity and continue to provide continued mitigation to this risk. Exposure to GHG risk is also reduced since non-emitting resources approach 75% by 2020/21.

Figure 40: Generation Mix



10.4. Sensitivity Analysis

Under the base assumptions, the integrated plan is the most economic. However, in order to assess the robustness of the Integrated Plan, it must be tested under varying key assumptions. The integrated expansion plan must not only be lowest cost for a single estimate of future conditions, but must be flexible by responding well to changes in major input assumptions.

Robustness is the measure of the integrated plan's ability to remain the least-cost plan under changing conditions. The sensitivity analysis in this study involved re-optimization of supply options under changes to major input assumptions related to the given sensitivity. This process allowed supply options to compete once again, and allowed them to be replaced, deferred, advanced or removed in response to the changing conditions.

In general terms, sensitivity analyses investigate the effects of uncertainty on a study or model. Within the context of this IRP, sensitivity analyses determine the robustness of the integrated plan by identifying what source of uncertainty weighs more on the study's conclusions.

In most IRP studies, changes from the base assumptions are simply formulated as "what if" analyses, testing important input assumptions with high and low scenarios. In some instances, Monte Carlo simulation studies are then undertaken to address the issue of the likelihood of a critical input parameter occurring. However, this assumes that the probability distribution of the parameter is well behaved. Few parameters in finance or economics have well-defined probability distributions. This is especially true for parameters related to energy production and prices. In addition, full Monte Carlo simulations require intensive computation resources, compounding with each additional sensitivity parameter, leading to hundreds of simulation runs. For these reasons, this analysis has applied a knowledge-based approach where all quantifiable information is assembled and synthesized to form a reasonable upper and lower bounds of the critical parameter. The notable shortcomings of this type of analysis are the interactive effects of varying different parameters. Therefore, "stress cases" were developed that vary groups of input parameters that are linked under plausible future scenarios.

The critical supply parameters that have the most relevance in this IRP are:

- Capital costs
- Fuel prices
- Load forecast
- GHG regulation and prices, and
- Stress case evaluation

The key output of the scenario evaluation is the least-cost expansion plan. The sensitivities and scenarios aim to test the limits of the integrated plan to ensure that it is robust and remains the least cost plan over a wide range of possible assumptions. Certain expansion plan items are included as base assumptions and therefore are outside the scope of the sensitivity analysis. These include Embedded Generation, LORESS and Mactaquac Life Achievement.

10.4.1. Capital Costs

There are many factors that influence capital-related costs of projects. This study has isolated three key areas that influence NB Power:

- direct capital cost risk
- construction price escalation, and
- financing rates

Direct Capital Cost Risk
As with any capital project, there are risks of capital cost overruns. Power plant costs are relatively well defined because many times the components are large and often built offsite by the manufacturer. These component manufacturers are very competitive, and fixed-price contracts are normally specified. Therefore, a range of ±25 per cent was considered. Figure 41 provides the result of this sensitivity applied to the integrated plan.

Figure 41: Cost summary of capital cost risks

	Integrated Plan	All Capital +25%	All Capital -25%
PVRR ($2017)	$ 24.6 B	$ 24.9 B	$ 24.3 B
Additional Cost from Integrated Plan		$ 0.3 B	-$ 0.3 B
Average Annual GHG Emissions	3.5 Mt	3.5 Mt	3.4 Mt

In the All Capital +25 per cent sensitivity, the least-cost expansion plan aligns closely with the integrated plan. The key difference that one of the more capital intensive units (NGCC) is replaced with combustion turbines, having lower capital costs. In the All Capital -25 per cent sensitivity, some capital intensive, low fuel cost options become economic choices. A wind farm of 200 MW is included in 2031, as well as Grand Falls Expansion in 2040/41. The detailed expansion plans are included in Appendix 6 (Sensitivity Analysis Expansion Plans).

Financing Rates
The weighted average cost of capital (WACC) in the private sector has been assumed in this study at approximately 7.13 per cent, while the WACC assumed for public sector development in New Brunswick is 5.9 per cent (this rate was applied throughout this report). The cost of

capital in the public sector is lower due to government backing. Applying the higher WACC rate would increase the cost of all supply options. For additional information, refer to Section 7.1.2 (Private Versus Public Financing). Figure 42 shows the effect of applying the private financing rates.

Figure 42: Results for private financing sensitivity

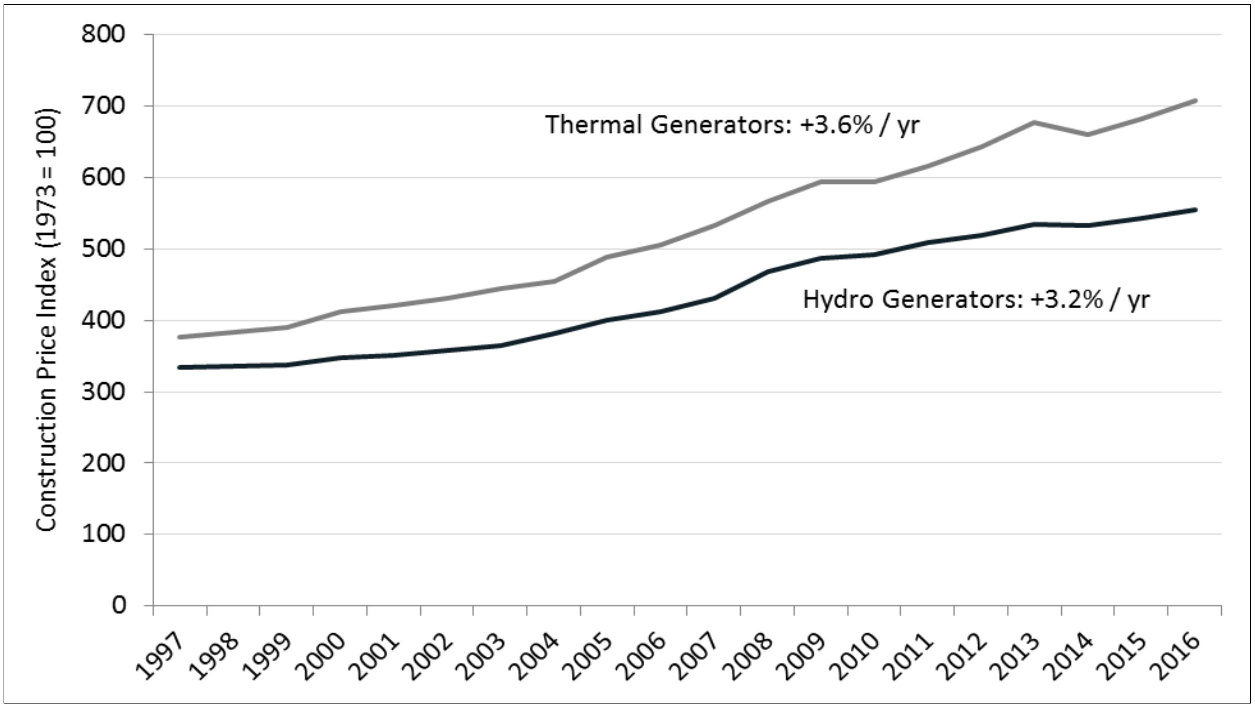
	Integrated Plan	Private Financing (WACC = 7.13 %)
PVRR ($2017)	$ 24.6 B	$ 24.7 B
Additional Cost from Integrated Plan		$ 0.1 B
Average Annual GHG Emissions	3.5 Mt	3.5 Mt

The integrated plan remains the least-cost expansion plan under this sensitivity. The detailed expansion plan is included in Appendix 6 (Sensitivity Analysis Expansion Plans).

Construction Price Escalation

Some of NB Power's existing generating facilities will come to their end-of-life dates during the period of this study. Significant capital construction will be required to replace the aging infrastructure. The Handy-Whitman Index of Public Utility Construction Costs has been published regularly for over 90 years. The Handy-Whitman Index is commonly used in this industry to reflect costs for capital construction. The index is projected to escalate at 3.6 per cent per year, for thermal units and 3.2 per cent per year for hydro facilitates based on Figure 43.

Figure 43: Handy-Whitman Index (1973 = 100)[19]



See Section 5.8.3 (The Construction Price Escalation) for additional information. The handy-Whitman Index is created using past history and is a reasonable cost projection for mature technologies. Some newer technologies have not fully matured and could stray from the benchmark 3.6 per cent. The levelized cost of wind projects has not grown at the same rate in recent years due to technological advances allowing the achievement of higher capacity factors. Figure 44 shows the effects of construction price escalation of 2 per cent per year for wind technologies.

Figure 44: Results for low wind escalation sensitivity

	Integrated Plan	Low Wind Escalation
PVRR ($2017)	$ 24.6 B	$ 24.6 B
Additional Cost from Integrated Plan		$ 0.0 B
Average Annual GHG Emissions	3.5 Mt	3.4 Mt

[19] Cost Trends of Electric Utility Construction – North Atlantic Region "Handy-Whitman Bulletin No. 183" (2016).

The results show that if wind capital costs were to escalate at a lower than average rate, it becomes economic to install 600 MW in 2040/41, offsetting the need to build a natural gas combined cycle unit. The cost impact during the study period is minimal, and there is a slight decrease in GHG emissions. The expansion plan for the low wind escalation sensitivity is included in Appendix 6 (Sensitivity Analysis Expansion Plans).

The integrated plan demonstrates its robustness against capital-related changes with very little variation in costs. The least-cost plan for the low capital sensitivity calls for new wind generation to be built in 2030/31. It will be important that NB Power continually evaluate the cost of wind generation as it compares to fuel and purchased power costs from the existing system especially as the requirement for new capacity approaches.

10.4.2. Fuel Prices

Fuel is one of NB Power's largest expenses. The industry has experienced extreme volatility in fuel prices in recent years. Any long-term plan must address the risk of the cost of the fuels that will be used.

Nuclear
The price of nuclear fuel has historically remained stable and lower than fossil fuel prices. There is no indication that this will change. Therefore, a sensitivity of the fuel price of nuclear was not considered necessary.

Heavy & Light Fuel Oil
Heavy fuel oil (HFO) is utilized at NB Power's Coleson Cove Generating Station. However, the utilization of heavy fuel oil is relatively low due to high prices and relatively high heat rates (low thermal efficiency) of current and new, oil-fired thermal plants. Light fuel oil (LFO) is used at existing combustion turbine plants (Millbank, Ste Rose and Grand Manan). The utilization is also very low due to high fuel cost and high heat rates of the combustion turbine units. Typically they would only run for system stability or during contingencies. Therefore, oil is not considered to be an economic option for electricity generation in the future.

Coal
Coal is a relatively low-cost fuel used at NB Power's existing generation asset located in Belledune. Because of the relatively low price, there is little room for downward coal price movement. Also, when considering the associated GHG issues, price increases are unlikely. Due to new regulations regarding coal, no new coal plants were considered in this study. Therefore, a sensitivity of the fuel price of coal was not considered necessary. It is expected that the sensitivities around GHG management strategies will have a large impact on existing coal generation.

Natural Gas

Natural gas is a premium fuel that is expected to be abundantly available into the future. Compared to other fuels such as nuclear and oil, natural gas has a high level of public acceptance. In the future, it is expected that natural gas will be the fuel of choice for electricity production as society transitions to a reduced GHG world.

There is a strong correlation between the price of natural gas and the market price of electricity. This leads to the conclusion that the sensitivity analyses for natural gas prices and the market price of electricity should not be done in isolation. Therefore, sensitivities of +25 and -25 per cent were applied to natural gas and electricity market prices concurrently for this study.

Figure 45: Results for natural gas and market price sensitivities

	Integrated Plan	Gas and Market Prices +25%	Gas and Market Prices -25%
PVRR ($2017)	$ 24.6 B	$ 24.8 B	$ 24.3 B
Additional Cost from Integrated Plan		$ 0.2 B	-$ 0.3 B
Average Annual GHG Emissions	3.5 Mt	3.7 Mt	2.9 Mt

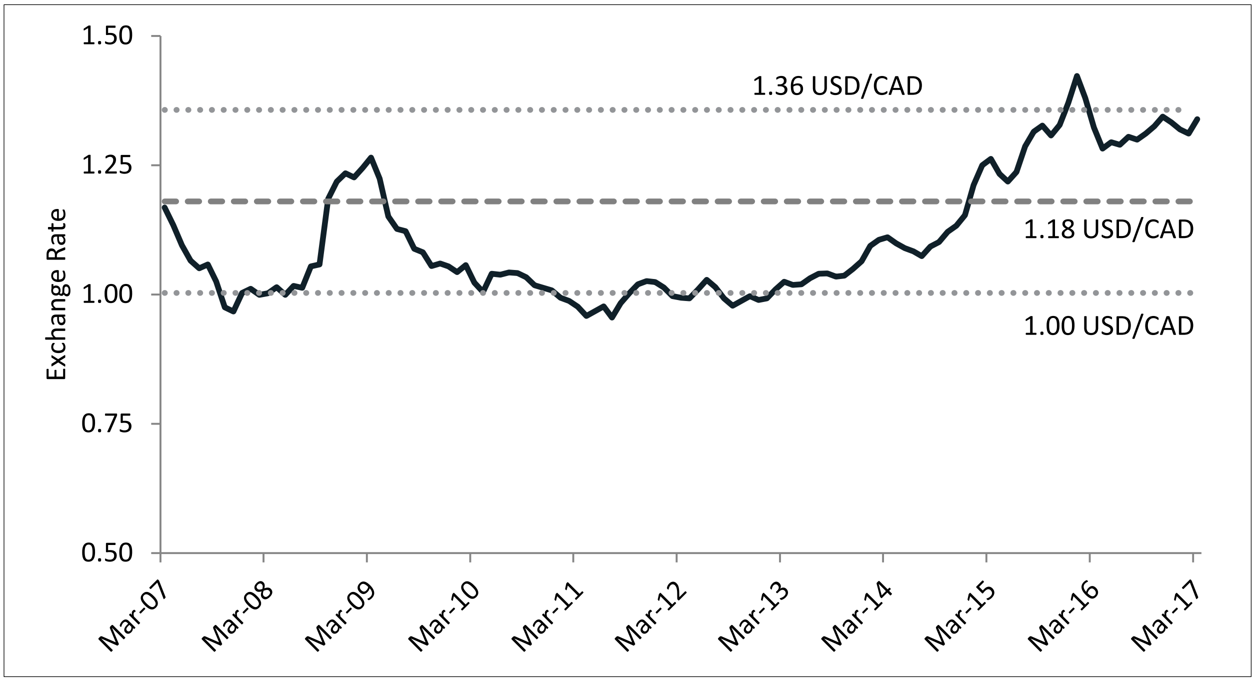
The high gas and high market price sensitivity results in the least-cost plan that includes two high capital, low fuel price technologies. 200 MW of wind is installed in 2030/31 and a 100 MW expansion to Grand Falls Hydro station is included in 2040/41. Increased prices for low emission electricity sources (market, natural gas) results in increased utilization of higher emitting coal and oil fired stations. Any emission reduction that would have been gained by the addition of renewables is more than offset by increases in generation from higher emitting fuels.

The integrated plan remains the least-cost expansion plan under the low gas and low market price sensitivity. The plan relies heavily on market purchases and natural gas generation, so this scenario has the impact of lowering the costs. Additionally, the emissions are reduced as generation from the lower emission electricity sources (market and natural gas) increases, while generation from heavy fuel oil and coal decreases. Detailed expansion plans are included in Appendix 6 (Sensitivity Analysis Expansion Plans).

Foreign Exchange Rates

Most fuels purchased by NB Power are priced based on the US market, and therefore priced in US dollars (USD). The exchange rate between the Canadian dollar (CAD) and the USD is a major risk for NB Power. The integrated plan assumes a long-term exchange rate of 1.18 USD/CAD (i.e. 1USD = 1.18CAD). The historical foreign exchange rate (FOREX) is shown in Figure 46.

Figure 46: 10-year historical foreign exchange rate and forecasts



The foreign exchange rate affects not only fuel prices, but also electricity market prices. Therefore, this sensitivity was applied to all fuels and all market-based transactions. The results are summarized below in Figure 47.

Figure 47: Cost summary of foreign exchange sensitivities

	Integrated Plan	FOREX +15% (USD/CAD)	FOREX -15% (USD/CAD)
PVRR ($2017)	$ 24.6 B	$ 25.3 B	$ 23.9 B
Additional Cost from Integrated Plan		$ 0.7 B	-$ 0.7 B
Average Annual GHG Emissions	3.5 Mt	3.4 Mt	3.5 Mt

The increased foreign exchange sensitivity results in the least-cost plan that includes two high capital, low fuel price technologies. 200 MW of wind is installed in 2030/31 and a 100 MW expansion to Grand Falls is included in 2040/41. Under the low foreign exchange sensitivity, the least cost plan is very close to the integrated plan. Detailed expansion plans are included in Appendix 6 (Sensitivity Analysis Expansion Plans).

The integrated plan demonstrates its robustness against fuel-related changes with little variation in cost and no significant changes to the expansion plan in the near term. The least-cost plans for the scenarios with higher fuel and market prices built 200 MW of wind generation in 2030/31. It will be important that NB Power continually evaluate the cost of wind generation as it compares to fuel and purchased power costs from the existing system in the future.

10.4.3. Load Sensitivities

Load Forecast

This study has used the most recent NB Power load forecast completed in August 2016.
A 95 per cent confidence interval was used for the high and low forecasts, based on statistical analyses of historical and future trends.

Figures 48 and 49 illustrate the impact on electricity requirements in New Brunswick. These charts also show historic load within New Brunswick.

Figure 48: Changes to energy forecast (before Energy Smart NB reductions)

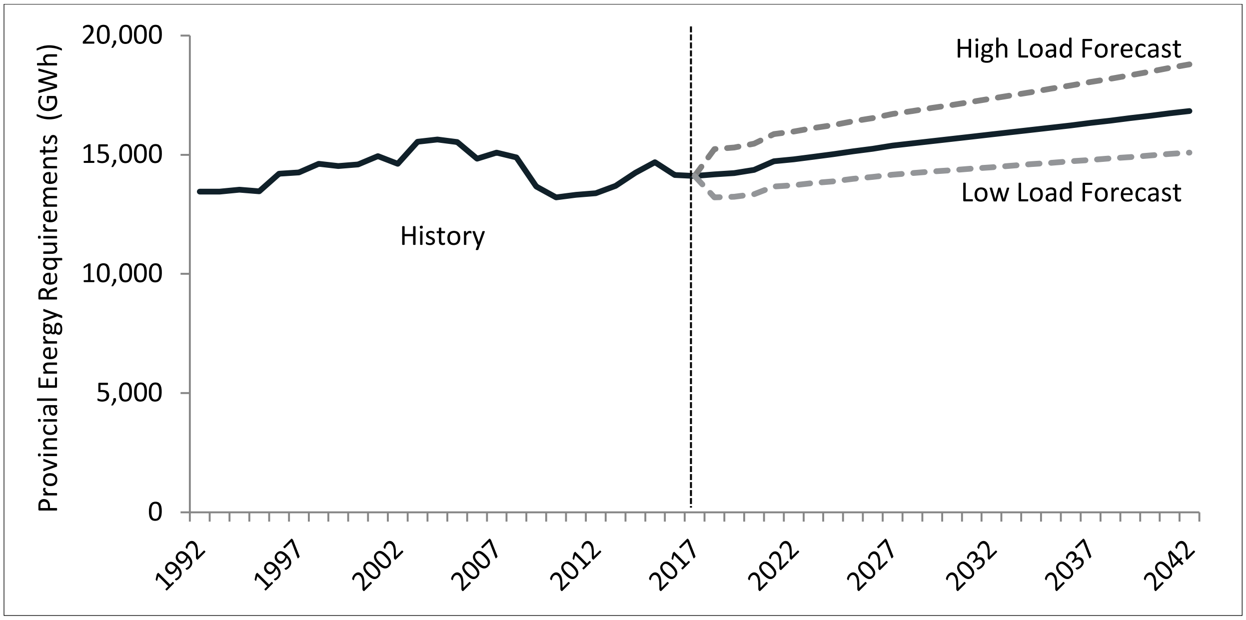


Figure 49: Changes to peak demand forecast (before Energy Smart NB reductions)

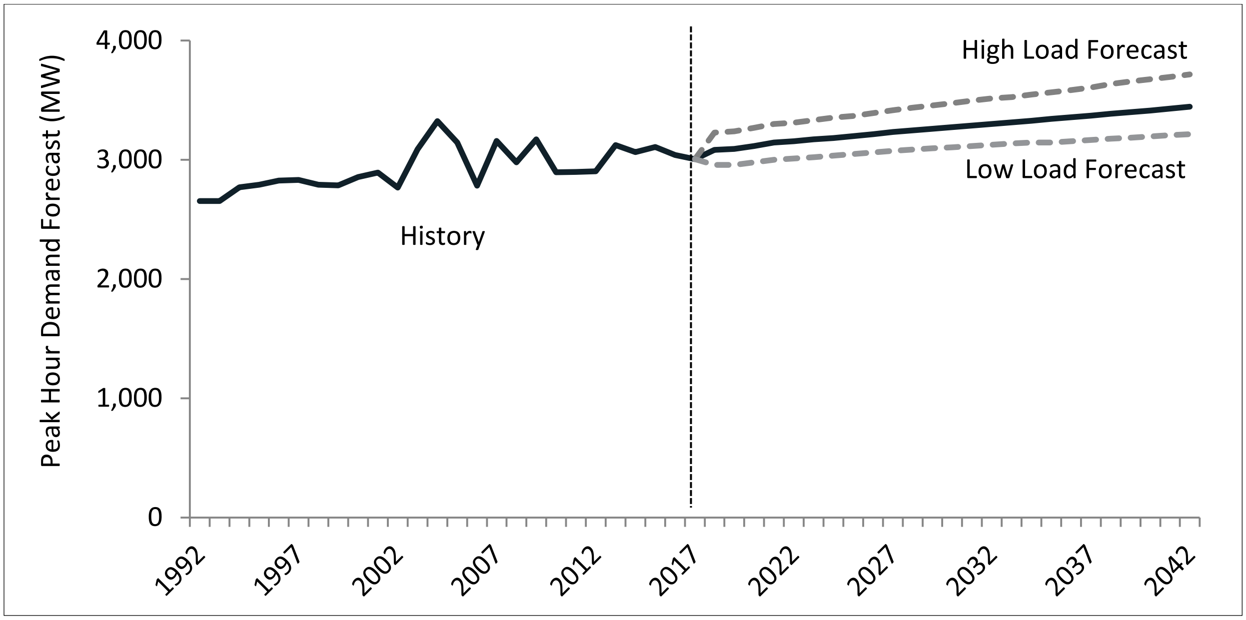


Figure 50: Cost summary of load forecast sensitivities

	Integrated Plan	High Load Forecast	Low Load Forecast
PVRR ($2017)	$ 24.6 B	$ 26.4 B	$ 23.2 B
Additional Cost from Integrated Plan		$ 1.8 B	-$ 1.4 B
Average Annual GHG Emissions	3.5 Mt	3.7 Mt	2.8 Mt

In all load forecast sensitivity plans, the options chosen are similar. The additional load requirement under the high load forecast advances the refurbishment of the remainder of the Millbank / Ste Rose units in 2030/31 and builds two additional combustion turbine units in 2040/41. The low forecast sensitivity builds one fewer natural gas combined cycle plant. Expansion plans are included in Appendix 6 (Sensitivity Analysis Expansion Plans). Overall, the least-cost plan is not sensitive to load changes in the short-to-medium horizon.

Energy Efficiency

NB Power received three energy efficiency scenarios from Dunsky Consulting Ltd. The base scenario achieved a similar level of energy efficiency to what NB Power was previously targeting.

Figure 51: Cost summary of energy efficiency sensitivities

	Integrated Plan	High Energy Efficiency	Extreme Energy Efficiency
PVRR ($2017)	$ 24.6 B	$ 24.4 B	$ 24.7 B
Additional Cost from Integrated Plan		-$ 0.2 B	$ 0.1 B
Average Annual GHG Emissions	3.5 Mt	3.2 Mt	3.1 Mt

Traditionally, the energy efficiency programs rely on passing benefit-cost ratio tests. The energy efficiency programs that are over and above the base amount included in the integrated plan have significantly reduced benefit-cost ratios. This means that there is diminishing value associated with increased efficiency programs above the baseline amount. In the extreme energy efficiency sensitivity, there is no payback for the programs, and the net benefit is negative.

Figure 52: Energy Smart NB and efficiency program net benefits

	Base Energy Smart NB Plan	Incremental Plan (High Sensitivity)	Incremental Plan (Extreme Sensitivity)
Cost ($2017 PV)	$ 1.3 B	$ 0.8 B	$ 1.6 B
Gross Benefits ($2017 PV)	$ 2.4 B	$ 1.0 B	$ 1.5 B
Net Benefits ($2017 NPV)	$ 1.1 B	$ 0.2 B	$-0.1 B

The inclusion of additional energy efficiency programs is not deemed to be prudent at this time because of increased risk associated with high cost and low return of the programs. NB Power will continue to evaluate energy and demand reduction targets and set goals in the three year DSM plan that are flexible and can be adjusted over time. Detailed expansion plans are included in Appendix 6 (Sensitivity Analysis Expansion Plans).

Solar PV Projections

The electricity sector is transforming as the availability of new customer options becomes available. One of the most significant impacts of this transformation in the future is the option for customers to own their generation. NB Power has evaluated a medium and high scenario for solar penetration based on forecasts received from Dunsky Energy Consulting Ltd. Both scenarios assume no change to the current net metering policy.

Figure 53: Solar projections from Dunsky Energy Consulting Ltd.

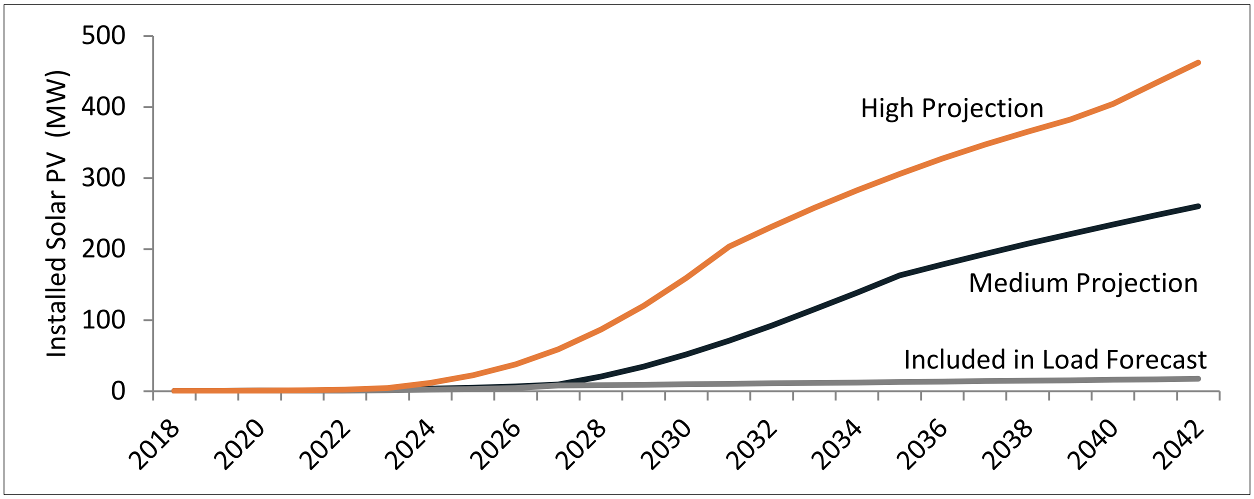


Figure 54: Cost summary of solar PV sensitivities

	Integrated Plan	Medium Solar Penetration	High Solar Penetration
PVRR ($2017)	$ 24.6 B	$ 24.5 B	$ 24.4 B
Additional Cost from Integrated Plan		-$ 0.1 B	-$ 0.2 B
Average Annual GHG Emissions	3.5 Mt	3.4 Mt	3.4 Mt

The costs are not impacted significantly by the installation of customer owned solar PV. There is, however, a decrease to energy sales revenue which is higher than the decrease to the system cost. What this means is that the current net-metering program is not sending the correct price signal to customers looking for alternative electricity choices, and that large penetrations of solar PV will result in higher costs being borne by customers without solar PV. It will be important that NB Power continue to monitor this trend and evaluate the appropriate business model that provides appropriate price signals to customers. There were no significant changes to the least-cost expansion plan for the solar PV sensitivities. Detailed expansion plans are included in Appendix 6 (Sensitivity Analysis Expansion Plans).

10.4.4. GHG Regulation and Prices

As indicated in Section 5.5 (Environmental and Sustainability Considerations), the possible GHG regulation remains very complex with many uncertainties. This study has assumed standard performance metrics for existing and new fossil units, to which various carbon regimes were then applied.

The variability of carbon prices in existing markets and current studies are significant. Because of the risk associated with carbon prices and uncertainty with respect to allocation, three GHG management sensitivities were examined. The first two were simply caps for the entire electricity sector at 3.0 Mt and 2.5 Mt. The third includes a price on carbon as well as coal phase out as outlined by the federal government.

Carbon Cap
In lieu of a carbon price, a carbon cap was applied to system wide emissions. It was assumed that Belledune would be retired and coal phased out by 2041. The results are shown below.

Figure 55: Cost summary of varying CO2 Cap levels

	Integrated Plan	CO2 Cap: 3.0 Mt	CO2 Cap: 2.5 Mt
PVRR ($2017)	$ 24.6 B	$ 25.1 B	$ 25.4 B
Additional Cost from Integrated Plan		$ 0.5 B	$ 0.8 B
Average Annual GHG Emissions	3.5 Mt	2.9 Mt	2.4 Mt

As shown in Appendix 6 (Sensitivity Analysis Expansion Plans), the integrated plan remains robust against the 3.0 Mt cap level but to achieve the lower cap level of 2.5 Mt, new renewable resources must be added which increases the present value of revenue requirements by about 3 per cent versus the integrated plan.

Federal GHG Regulation
The federal government is contemplating two new rules related to greenhouse gas emissions. The first is to impose a carbon price starting at $10/tonne in 2018, ramping up to $50/tonne in 2022. This would be consistent with imposing a carbon tax. The second rule imposed would be to phase out coal by 2030. For purposes of this sensitivity, it is assumed that both of these standards come into effect.

Figure 56: Cost summary of the Federal GHG regulation sensitivity

	Integrated Plan	Federal GHG Regulation
PVRR ($2017)	$ 24.6 B	$ 27.1 B
Additional Cost from Integrated Plan		$ 2.5 B
Average Annual GHG Emissions	3.5 Mt	2.5 Mt

The costs resulting from the federal GHG regulation are high for the amount of emission reduction achieved. The average emissions are similar to those achieved in the 2.5 Mt cap sensitivity above, but the additional costs are tripled in comparison. There is also a potential cascading effect through the potential loss of industrial and commercial load as costs for compliance could be transferred to these customers. This sensitivity highlights the need for a made-in-New Brunswick GHG management strategy. .

In this sensitivity, the least-cost plan requires new capacity in 2031 to replace the loss of Belledune. Much of this capacity is renewable based. Detailed expansion plans are included in Appendix 6 (Sensitivity Analysis Expansion Plans).

The Government of New Brunswick is working with NB Power and the federal government to develop a made-in-New Brunswick GHG management strategy and to explore all options to minimize the cost to New Brunswickers. As the direction on the carbon strategy for New Brunswick becomes clearer, NB Power will review the necessity to refresh this IRP.

10.4.5. Scenario Evaluation

The sensitivity analysis thus far has evaluated the robustness of the Reference Plan under a wide range of changing conditions on an individual and isolated basis. Further analysis was also performed using multiple sensitivities combined to once again determine the robustness of the Integrated Plan. Two different scenarios were developed. The first assumed that government policy and social pressures would result in increased electrification of the economy and limits on GHG emissions. This would have the effect of increasing load, increasing solar PV penetration and driving up demand (and price) for electricity and natural gas. A second scenario was developed that reflected a global recession case, where low cost energy was given priority, and environmental restrictions and regulations were relaxed. This scenario would result in lower load as well as decreased demand (and price) for natural gas and electricity. These scenarios and corresponding assumptions are summarized in Figure 57.

Figure 57: Scenario analysis assumptions

	Scenario 1: High Electrification	Scenario 2: Global Recession
Load Forecast	High	Low
Energy Efficiency	No change	No change
Solar Penetration	High	No change
Natural Gas Prices	+ 25 %	- 25 %
Market Prices	+ 25 %	- 25 %
Carbon Prices	No change	No change
Carbon Cap	3.0 Mt	No change

Figure 58: Cost to the Integrated Plan associated with various scenarios

	Integrated Plan	Low Emission / High Electrification	Global Recession
PVRR ($2017)	$ 24.6 B	$ 27.1 B	$ 22.8 B
Additional Cost from Integrated Plan		$ 2.5 B	-$ 1.8 B
Average Annual GHG Emissions	3.5 Mt	2.9 Mt	2.4 Mt

Under the high electrification case, the expansion plan includes a significant increase in renewable development. A 100 MW hydro unit at Grand Falls is installed in 2022/23 as well as 200 MW of wind installed in both 2020/21 and 2030/31. This is due to high fuel and market prices as well as GHG limits. In the global recession scenario case, the only major deviation from the integrated plan is that one fewer natural gas combined cycle unit is required in 2040/41. Detailed expansion plans are included in Appendix 6 (Sensitivity Analysis Expansion Plans).

11. CONCLUSION

The results of this IRP study provide information regarding the strategic course of action that NB Power should consider to meet its future resource needs. The following statements reflect the IRP results:

1. New capacity will not be required until 2027 or later.
2. The most cost-effective future resource mix is composed of renewable resources in the initial period to meet the RPS requirement, with continued emphasis on Energy Smart NB.
3. The peaking resources can be provided most economically with a combination of the Energy Smart NB program, peak interconnection purchases and combustion turbines.
4. The amount of cost-effective capacity and energy reductions associated with the Energy Smart NB plan is projected to be 59 MW and 215 GWh respectively by 2019/20, and grows to 621 MW and 2,301 GWh by 2041/42.
5. The Energy Smart NB plan results in a $1.1 billion net decrease to the present value of NB Power's revenue requirements over the planning period.
6. In order to achieve sufficient Energy Smart NB capacity to avoid construction of new combustion turbines, the current Energy Smart NB plan schedule should continue with increasing effort over the long-term.
7. GHG levels to meet in-province load remain below the 2005 historical levels.
8. Base and intermediate load requirements required to meet the expiration of existing natural gas power purchase agreements are most economically achieved by new renewables and Energy Smart NB.
9. Millbank and Ste. Rose life extension is the most economic choice for continued peak load requirements after the current retirement date.
10. Mactaquac Generating Station continued operation is reflected through life achievement.
11. Continued examination of new and innovative technologies and business models will be necessary to ensure the latest information and customer options are available, and to ensure a diverse mix of generation in the long term.
12. Energy Smart NB will help reduce exposure to changes in future assumptions.

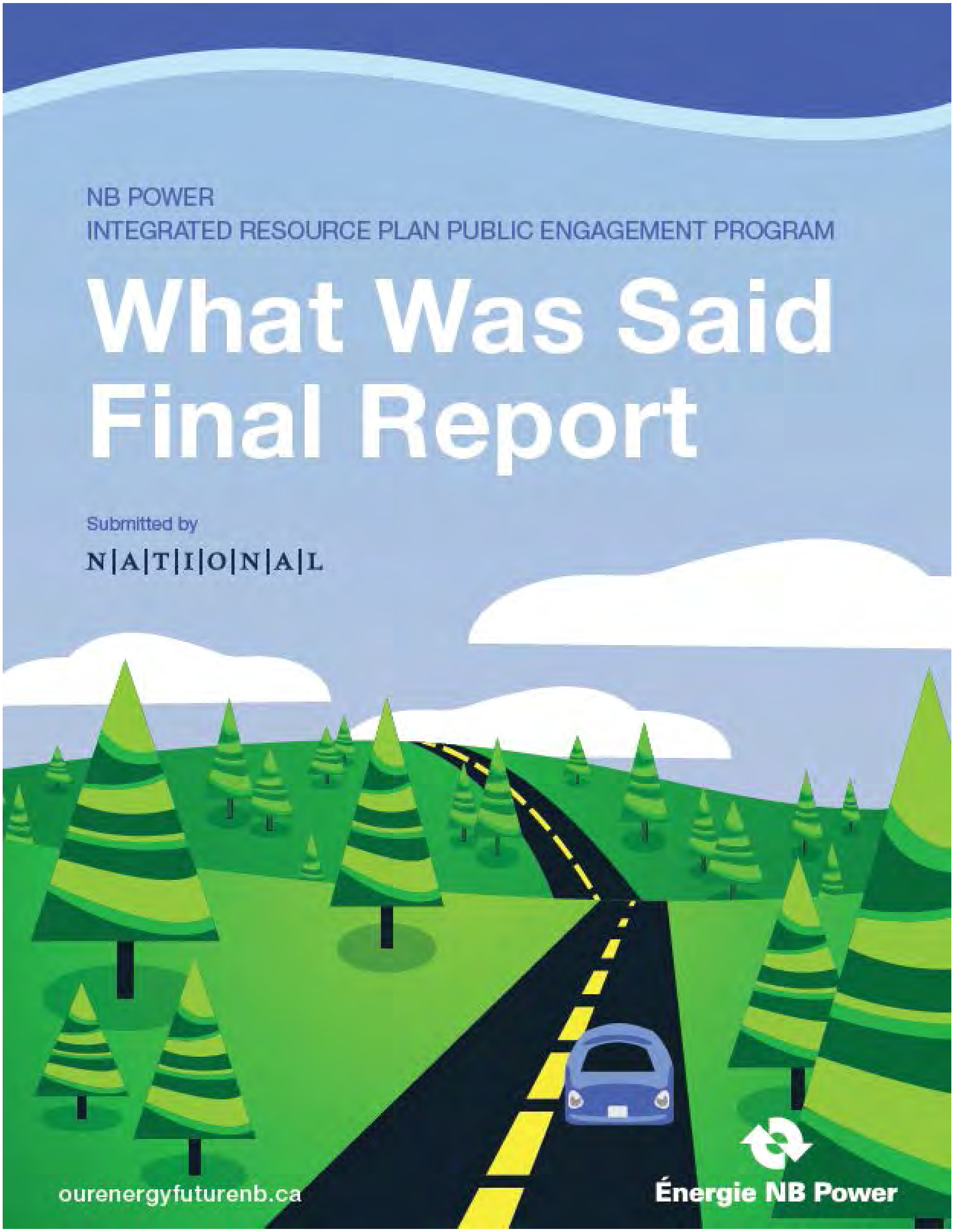
In summary, the strategic direction recommended over the immediate term is:

- Continued development of the Locally-owned Renewable Energy Projects that are Small Scale (LORESS) and Embedded Generation Programs to meet the RPS;
- Continuation of Energy Smart NB plan with increased development in the long-term; and
- Continuation of technical work with regards to new generation options and business models that might be viable in New Brunswick, especially options from customer owned renewable resources.

12. APPENDICES

Appendix 1: IRP Public Engagement Program- What Was Said Final Report
Appendix 2: List of assumptions for IRP
Appendix 3: Fuel and Market Price Forecast – Reference Case
Appendix 4: Supply Options
Appendix 5: Project and Operating Cost Parameters
Appendix 6: Sensitivity Analysis Expansion Plans
Appendix 7: Glossary and Abbreviations

Appendix 1: IRP Public Engagement Program - What Was Said Final Report



What Was Said Report

NB POWER OUR ENERGY FUTURE 2017

METHODOLOGY

As the planning period of the Integrated Resource Plan is 25 years, it was important to gain a deeper understanding of what's important to customers as they consider New Brunswick's electricity future, and the role they're willing to play to achieve those objectives.

Customer engagement on the Integrated Resource Plan (IRP) was carried out between March 12, 2017 and May 15, 2017. The design of the engagement process was a collaborative effort between the NB Power team and NATIONAL, with survey design and data analysis services provided by Thinkwell Research.

Program goal

- To gather values-based input from New Brunswickers about the province's electricity future to inform NB Power's 2017 Integrated Resource Plan.

Objectives

- Gain a deeper understanding of what is most important to customers as they consider the province's energy future, and the role they're willing to play to achieve those objectives.
- Provide sufficient and appropriate contextual information, in an easy to understand format, about the province's energy landscape, the scope of the IRP process, and what can be influenced.
- Host a values-based engagement process in person and online that allows New Brunswickers to contribute based on their own perspective, experience, ideas, and what is most important to them.
- Be transparent in sharing what emerges from the consultation effort.

What Was Said Report

Scope of engagement

The engagement program consisted of an online survey hosted on the website OurEnergyFutureNB.ca and customer engagement sessions hosted in Fredericton, Moncton, and Beresford.

Efforts to raise awareness of the engagement process and to invite customer participation were extended through: newspaper advertising, social media advertisements (Facebook, Twitter, and YouTube), media relations, direct invitations to stakeholders, and via NB Power's own communications channels (e.g. website, social media).

Input was gathered from 1,221 New Brunswickers online, of which 16% of respondents were from Maliseet and Mi'kmaq communities (identified by their first three postal code digits). Three engagement sessions were held with 52 total participants, and three stakeholder organizations made formal submissions of input to the process.

Online engagement approach

The online engagement experience was designed with a general public audience in mind. Content was developed to be concise and used plain language. An informational video was produced to provide context for the discussion and the questions posed.

The survey was short and the questions direct. It explored the following topics:

- Affordability
- Clean Energy
- Customer Options

Participants were also provided with an open-ended opportunity to share additional information regarding what was important to them, and those qualitative inputs were coded into conceptually meaningful categories and quantified with NB Power.

In-person engagement approach

The customer engagement sessions were hosted in a world café format.

Representatives of the NB Power executive team served as hosts, and a presentation by Michael Bourque, Director of Integrated Resource Planning provided important context for the discussion. That presentation consisted of: an overview of the IRP, the current situation, outcomes of the 2015 IRP process, possible options for the future, and the increased role customers might play.

Participants were facilitated through an exploration of the following three questions:

- When considering New Brunswick's electricity future, what's most important to you?
- What do we need to be successful in advancing these priorities?
- What can customers do to help advance these priorities?

ONLINE ENGAGEMENT FINDINGS

Summary

The results of the online survey indicate that clean energy and affordable rates are both high priorities among New Brunswickers who participated. Respondents mostly agreed with statements related to these two considerations.

The one exception is that there was less agreement overall with the statement 'I am personally willing to pay more for clean energy' than other statements on this topic. This suggests that at least for some, there are limits to the degree to which they want NB Power to embrace this approach.

There were also some clear age divides on several questions. younger respondents (under the age of 35) expressed higher and more intense levels of agreement with statements that endorse clean energy, while older (55+) respondents did the same for statements that related to managing costs (keeping rates as low as possible, investing in options to allow them to better manage their energy use, etc.).

This should not be interpreted as meaning that younger respondents do not favour low rates, or that older respondents do not support clean energy. It does mean, however, that the age groups are more concerned and sensitive to one priority over the other.

The statements New Brunswickers had the highest level of agreement with, were:

What Was Said Report

Clean Energy

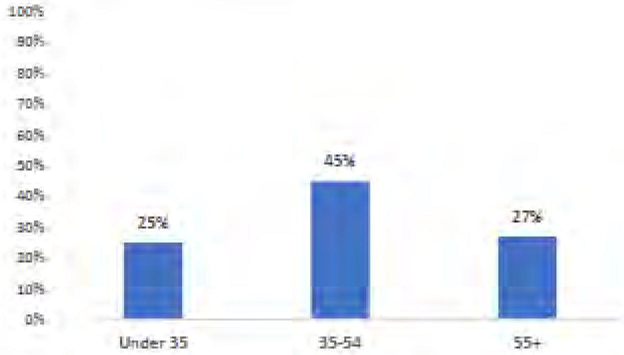
- I want NB Power to be a leader in energy efficiency
- I support using less fossil fuels as we transition to a cleaner energy future to meet our climate change commitments
- New Brunswickers have a responsibility to make changes to help address climate change

Customer Options

- I am willing to personally invest in equipment and technology to manage my electricity use and costs (e.g. insulation, programmable thermostats)

Detailed findings

The single largest group of respondents came from the middle age (35-54) category, at 45%. The proportion of younger (under 35) and older (55+) respondents was relatively equal (25% and 27% respectively).



What Was Said Report

Affordability:

Respondents were asked to rate their level of agreement with a series of statements on a scale of 1-5, where 1 means they *disagree*, and 5 means they *agree*.

Priority	4-5 rating (top-2 box)	3 rating	1-2 rating	DNK	Mean
I want NB Power to invest in providing more customer options to better manage my electricity use and costs	72%	17%	8%	3%	4.04
New Brunswick's transition to a clean energy future needs to minimize impacts on rates and the economy	68%	20%	10%	2%	3.99
NB Power's top priority should be keeping rates as low as possible	63%	22%	13%	2%	3.88
I am open to renewable power purchased from other jurisdictions rather than building new in New Brunswick to maintain stable rates	50%	20%	27%	3%	3.38
NB Power's top priority should be debt repayment	42%	37%	18%	4%	3.35

Clean Energy:

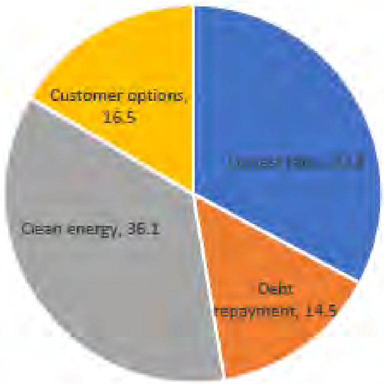
Priority	4-5 rating (top-2 box)	3 rating	1-2 rating	DNK	Mean
I want NB Power to be a leader in energy efficiency	86%	8%	3%	3%	4.49
I support using less fossil fuels as we transition to a cleaner energy future to meet our climate change commitments	79%	10%	8%	2%	4.29
New Brunswickers have a responsibility to make changes to help address climate change	76%	13%	9%	2%	4.17
NB Power's top priority should be moving away from fossil fuels to clean energy generation	74%	13%	11%	2%	4.12
I want NB Power to be a leader in clean energy	73%	15%	10%	2%	4.15
It is important to me that electricity for New Brunswick is made in New Brunswick	61%	19%	18%	3%	3.80
I am personally willing to pay for clean energy	51%	23%	23%	2%	3.51

Customer Options:

Priority	4-5 rating (top-2 box)	3 rating	1-2 rating	DNK	Mean
I am willing to personally invest in equipment and technology to manage my electricity use and costs (e.g. insulation, programmable thermostats)	77%	13%	7%	3%	4.19
I would be interested in generating my own electricity	71%	12%	14%	4%	4.07
I would be interested in participating in a "time-of-use" rate program to help manage my electricity use costs	65%	16%	15%	4%	3.86
NB Power's top priority should be offering customers options to better manage their electricity use	64%	22%	12%	3%	3.86
I would be interested in purchasing an electric car	50%	19%	27%	4%	3.40
I think it's NB Power's job to manage electricity use and costs	44%	33%	20%	4%	3.36

Establishing Priorities:

Respondents were also provided with an opportunity to indicate how much of a priority they place on four priorities for NB Power, out of a possible 100 points. The highest 'weight' was assigned to clean energy (36.1 average), followed very closely by the lowest rates (32.8). Customer options (16.5) and debt repayment (14.5) were not rated as strongly.



There were some age differences of note in two areas. Consistent with other findings on the survey, younger (under 35) respondents tended to place a higher weight on clean energy (41.8) than middle age (35.6) and older (32.5) respondents, while the reverse was true for the lowest rates (<35: 29.7; 35-54: 32.8; 55+: 35.5).

Other Comments:

Respondents were asked to indicate in an unaided fashion if there was anything else they wanted NB Power to know as they developed the IRP. The responses shown below are based on the 409 individuals who provided a response to this question.

There were some age differences of note in two areas. Consistent with other findings on the survey, younger (under 35) respondents tended to place a higher weight on clean energy (41.8) than middle age (35.6) and older (32.5) respondents, while the reverse was true for the lowest rates (<35: 29.7; 35-54: 32.8; 55+: 35.5).

Respondents from Maliseet and Mi'kmaq communities consistently articulated clean energy as a high priority, and the ability to generate power for sale back to the grid.

What Was Said Report

Category	Commenters (n=409)
Promote solar power	20%
Incentives/subsidies necessary to generate clean power	17%
Make clean energy a priority	11%
Allow consumers to sell excess power back to grid	9%
Make wind power a priority	9%
Keep rates low/minimize increases	8%
Promote tidal/hydro power	5%
Reduce management salaries	5%
NB Power needs to be a leader/is falling behind	5%
Focus on creating jobs/economy	5%
Invest in more nuclear power	5%
Rate protection for low income and seniors	4%
More education/awareness/ engagement	4%
Survey suggestions	4%
Better management of NB Power is needed	4%
Encourage consumers to generate their own power	4%
Focus on conservation programs	4%
Partner with leaders/others	3%
Avoid making the same mistakes as Ontario	3%
Make electric cars a priority	3%
No more nuclear power	3%
Incent time-of-day use	3%
Focus on debt reduction	2%
Praise for NB Power/survey	2%
Home energy report is a waste	2%
Invest in infrastructure for electric cars	2%
Better government leadership	2%
Avoid wind power	2%
Mismanagement of Point Lepreau	2%
Maintain grid/fewer outages	2%
Make Natural Gas a priority	2%
Take a balanced/careful approach	2%
NB Power is incompetent/corrupt	2%
Keep energy production in NB	2%
Other	14%

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CUSTOMER ENGAGEMENT SESSION FINDINGS

Summary

Customers had deep discussions during the engagement sessions about their priorities when considering New Brunswick's energy future. The general themes are reflected below.

Detailed Findings

When considering New Brunswick's electricity future, what's most important to you?

These are the comments shared with NB Power by participants, organized by theme:

What Was Said Report

Engagement

- Customers to take more personal action to be part of future solutions
- Diversity is important
- Community engagement is important, and matters
- Provide user-friendly tools for customers, in order for them to be able to learn about energy options – how are they consuming?
- Get customers involved (e.g. pilot projects)
- Everyone needs to do their part

Education

- NB Power to provide leadership and education on a sustainable energy future
- Customer education on cost comparison
- Educate students from a young age
- Education to help visualize consumption
- Education to inform behaviour

Clean energy and sustainability

- Clean and cost-effective energy
- Environment and our environmental responsibility
- Lower or eliminate carbon emissions
- Stop fossil fuels
- Better, sustainable housing
- Modernization
- Renewable energy
- Resiliency to confront challenges and climate change
- Carbon offset
- Shape a new identity for New Brunswick which is clean and green

Affordability & debt management

- The cost of energy and affordability
- Tackle debt
- Identify savings
- Economic impact of Belledune
- Stable cost and rates
- Bulk purchasing to keep the energy price(s) down

What Was Said Report

- Getting notifications to save money with Smart Grid
- To get a good ROI with investments
- Invest locally, with a good ROI
- Concern around the real cost of nuclear
- Long-term view of costs
- Investment
- Holistic view of cost for generation
- Be prepared to pay a little bit of a premium

Incentives

- Incentives and rebates
- NB Power to move forward with incentives
- Development of grants/incentives for individuals to get involved with wind/solar
- Incentive programs and plans for customers that install energy-efficient products, and complete energy-efficient construction projects—something that works for all of New Brunswick
- Incentives to adopt more renewable energy
- Financial incentives so New Brunswick can make more responsible energy choices
- Incentives for lower-than-average consumption

Supportive policy

- Engage leaders and politicians
- Drive the policy, and *"the why"*
- We need development in the North
- Investment in New Brunswick, and produce 100% of New Brunswick's power
- New Brunswick could be the lungs of Canada—buying credits from our province as they emit greenhouse gas emissions
- Government policies to support things like community-based projects
- Different levels of government to get aligned with the goals/visions of NB Power

Data & measurement

- Real-time data
- Notifications and opportunities to save/reduce
- Data-driven habits
- Real-time feedback and communications

What Was Said Report

First Nations

First Nations community representatives identified the following priorities during the Beresford engagement session:

- Inclusion of First Nations
- More green energy
- Affordability
- The environment
- Need for development in the North
- Opening markets
- Lower or eliminate carbon emissions
- Grants or incentives for wind/solar energy development

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What Was Said Report

What do we need to be successful in advancing these priorities?
What can customers do to help advance these priorities?

A breakdown of responses below:

RESPONSE	THEME
Make efficiency the "norm"	**Clean energy and sustainability**
Integration of new technologies	**Clean energy and sustainability**
Encourage alternative forms of energy, and heating sources	**Clean energy and sustainability**
Electric transportation–non-carbon electricity	**Clean energy and sustainability**
Get rid of coal	**Clean energy and sustainability**
More eco-friendly lighting *(including the broad acceptance of other new technologies)*	**Clean energy and sustainability**
Reliability *(increased storms, climate change, etc.)*	**Clean energy and sustainability**
Get off the grid–decentralize	**Clean energy and sustainability**
Distributed generation	**Clean energy and sustainability**
Energy independence	**Clean energy and sustainability**
Appliances that shut down	**Clean energy and sustainability**
Eco-friendly choices that are easy to make	**Clean energy and sustainability**
Integrate technology into the building materials	**Clean energy and sustainability**
Community energy planning	**Clean energy and sustainability**
Take simple personal actions to save on energy	**Clean energy and sustainability**
Solar power	**Clean energy and sustainability**

What Was Said Report

RESPONSE	THEME
Make cost of electricity more visible–time of use rates, etc.	**Data & measurement**
A well-defined program with clear KPI's	**Data & measurement**
Breakdown of information on bills	**Data & measurement**
Demonstrated results	**Data & measurement**
Transparent result-reporting	**Data & measurement**
Accountability	**Data & measurement**

RESPONSE	THEME
Education for seniors *(energy reduction)*	**Debt management and affordability**

RESPONSE	THEME
Webmail portal to receive customer ideas, to drive change *(get away from the more traditional models)*	**Engagement**
More community dialogue	**Engagement**
Cooperation	**Engagement**
More people present at discussions	**Engagement**
Empower customers	**Engagement**
Customers become producers	**Engagement**

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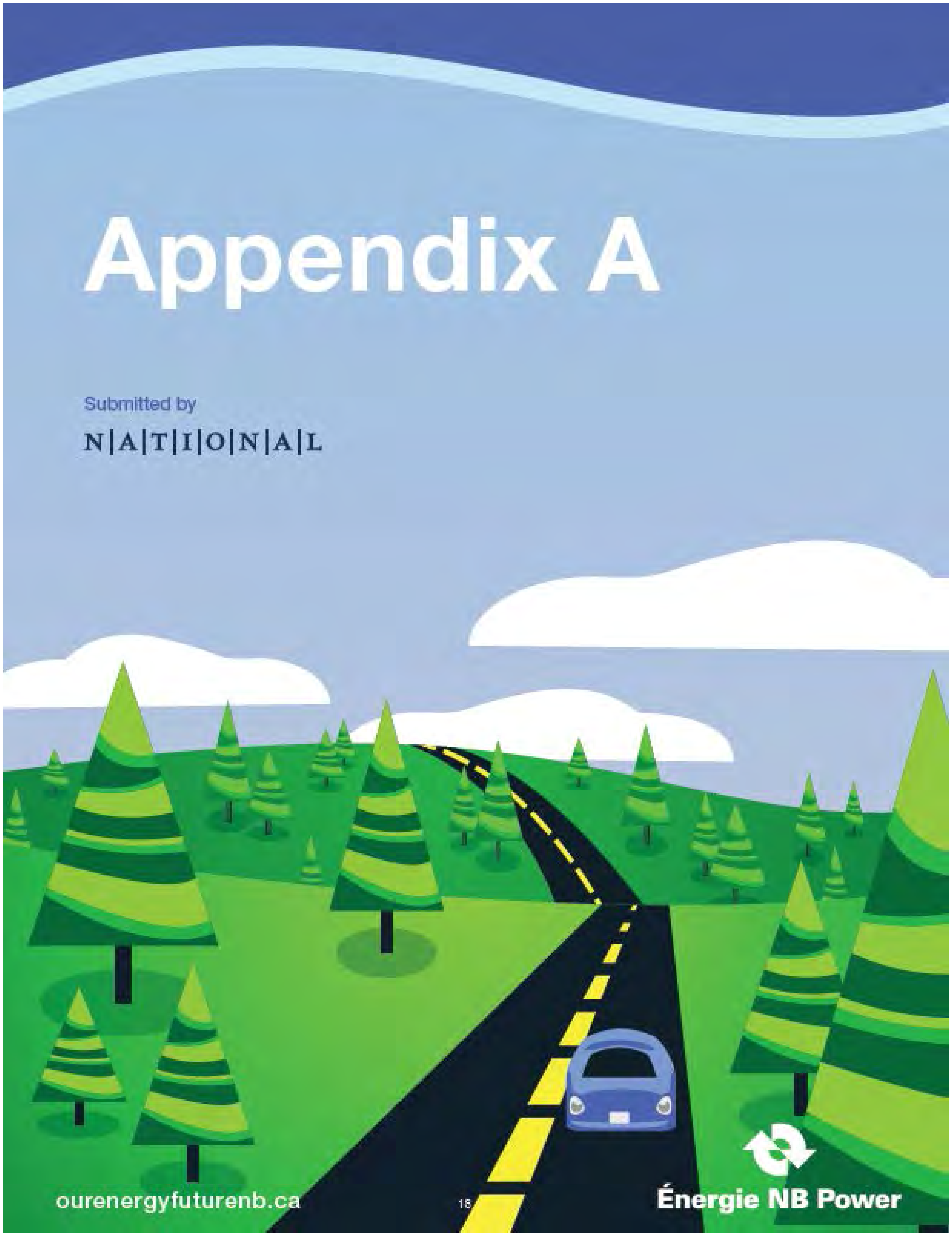
What Was Said Report

RESPONSE	THEME
Education leadership to create a change in mindset, develop a culture of respect, and not to waste resources	**Education**
Information	**Education**
Shifting education to avoid new builds	**Education**
Education models developed for schools *(by NB Power)* and have energy offering challenges between school districts	**Education**
Education for seniors *(energy reduction)*	**Education**
Dialogue on social media	**Education**

RESPONSE	THEME
Credits for energy efficiency in winter	**Incentives**
Incentives for wood pellet stoves and insulation in homes	**Incentives**

RESPONSE	THEME
Inform our government we want a change	**Supportive policy**
Carbon tax/pricing to change behavior	**Supportive policy**
Carbon tax/pricing to change behavior	**Supportive policy**


Appendix A
Submitted by
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Énergie NB Power

My name is Chris Rouse with New Clear Free Solutions. We would like to submit our fully integrated resource plan for consideration for your 2017 IRP process. We would like to be assured that this plan be presented to the government of NB as one of their choices in long term planning approval.

This is a link to our latest version of the IRP.

New Clear Free Solutions 2017 Integrated Resource Plan

In general, renewable energy is the same or lower cost than the fossil fuel and nuclear options. Given that these options are currently less expensive or similar cost there is no need to wait or defer their implementation, and there is no need for significant long term rate increase like currently planned by NB Power. Deferring the transition will only cost more in the long and short run, and is denying NB much needed jobs. It is a false choice to ask NB Brunswicker's if they are willing to pay more for green energy when it is less expensive.

Our plan has been misunderstood as only investing into renewables and not looking at energy efficiency and conservation. Our plan has also been misunderstood as ignoring the other sectors that make up NB emissions such as industry and Transportation. This is not true. There is $4.7 billion in our plan to be invested in these areas and was the "Dividend" column in our previous plans. This is a fully integrated resource plan for New Brunswick and not just for the electricity sector. NB Power is responsible for both the generation of electricity as well as efficiency programs, and as such we believe the best way to invest the Carbon Tax is through our publicly owned utility for the benefit of all New Brunswicker's.

Some of the money will be used to invest into electrode boilers which is at least a 30% efficiency gain and has huge emissions reductions and will save industry in energy costs compared to what they are currently paying. This is the only credible method for eliminating the emissions from this sector without the extensive use of biofuels. Biofuels is a limited resource and we should be conserving it and using other methods first. The increase in electricity sales will also help with NB Powers bottom line and help keep rates low and stable. The approximate cost to supply all industry in NB with an electrode boiler is approximately $200 million dollars.

The money will also be used to invest in the shift to electric transportation. This has another huge efficiency gain of more than 30%. At $300,000 per electric school bus and approximately 1200 school busses, $360 million of the 4.7 billion could be used to buy all new electric school busses. There are also approximately 1200 commercial busses. An electric commercial bus is approximately $300,000 more than a normal fossil fuel bus which we can incentivise at a cost of another $360 million. We can also use some of the revenue to incentivise the shift to electric cars and provide the infrastructure to make the shift like fast charging stations, and home charging stations.

Investing in these efficiencies have large emission reductions and benefits NB Power through increased sales and leads to lower overall energy cost for ratepayers while also maintaining low and stable rates. Investing in efficiency that reduces electricity consumption will make rates higher, choke the cash flow needed to make the transition, generally bad for business and only benefits those who get the efficiency. Also we have a very low carbon grid, already at around 75% carbon free, using less electricity has very little environmental benefits. Due to the high price of gasoline the shift in electric transportation should end up with consumers paying less overall energy cost. If we want to save money using efficiency the transportation sector is the place to do it in.

We should also use some of the money to invest in efficient government buildings that will make them more affordable. We all benefit from an efficient government. We can also offer low interest loans that can be paid back with energy savings and this should starting with low income families first. We can invest into efficiency but too much too fast creates a big problem, and it should not be the focal point of our long-term plans like the current RASD program.

We think NB Power should not be trying to change human behavior to accommodate their grid, although we do believe in education that may help integrate renewables. We object to time of use pricing as NB Power is telling me I must pay more to eat and shower at my normal times. NB Power should be focusing on demand side management technology that is transparent to the user and doesn't require behavior changes such as are award winning Power Shift Atlantic program, which NB Power has now defunded.

There is also ample money for climate change mitigation as the effects of global warming have already begun to affect New Brunswick.

We also think that people generating their own electricity is a large issue for NB Power especially if rates keep rising like currently planned. We suggest NB Power adopt the solar city business model for people who want to generate their own power. We also think the community power be limited as NB Power is community power. However, if there is a program most community energy projects are 70% debt financed and this source of financing should be the Carbon tax so that we all benefit.

We would like NB Power to consider all our evidence, IR's and testimony from the EUB matter 336 as part of this submission, as we made our detailed concerns very well known to senior management during that process. We requested that the board order NB Power to have a detailed stakeholder consultation with us, but their final decision has yet to be released. We would very much welcome and request a more detailed consultation about the IRP with NB Power. Interventions are by nature confrontational and we hope that our critique is not taken personally as it is meant to help and in the public's best interest

Both economic experts at the hearings thought that the best way to get NB Power out of the financial troubles was a large immediate rate increase because of the compounding nature of it. The carbon tax gives this large initial influx of cash recommended by them while keeping electricity rates low and stable.

We request that an option to phase nuclear out by 2030 be considered in the IRP. As stated by NB Powers own expert at the EUB hearings, the closing of Point Lepreau for any number of reasons poses a large financial risk on the Province. NB Power should be examining the potential early retirement of Lepreau. Nuclear technology has underperformed in every aspect of building and operating a generating plant and lifespan should not be overestimated either. From cost over runs, schedule delays, poor performance, increase ongoing capital cost and issues with waste and safety still not adequately addressed, NB Power has no logical reason for pursuing nuclear. It is an industry in decline and NB does not have enough money to prop up this failing industry. Given the recent bankruptcy of Toshiba there is currently not even any technology to buy. We cannot afford to be another nuclear guinea pig in NB. There is no technical need for nuclear power and we already have too much baseload. We request that geothermal be used to replace any base load requirements, as it is the same or less cost and more scalable to the size of our needs. According to the 2014 IRP we have a comparable geothermal resource to California.

As pointed out during the EUB hearings we have concerns with the fundamentals of NB Powers current business plans starting with NB Powers lack of vision, IRP methodology and concerns with the three strategic objectives and general management of our publicly owned utility. These concerns were mirrored by almost all interveners.

We also have the impression that NB Power is not properly using its strategist software and this software is largely responsible for our concerns with NB Powers three key strategies. Given the recent property tax software creating significant issues in the province we are also concerned with misunderstood software at NB Power. We object to NB Power blindly following the directions given by this piece of software.

We request that NB Power assess return on investment and not only the lowest cost option for this IRP process. The results of the IRP are currently being misrepresented as Net Present Value which they are not. Not considering lost revenue for the RASD program is a huge problem with the current 2014 IRP. While the RASD program claims to have saved approximately $450 million over 25 years it did not consider the lost revenue from the 2TWh of efficiency that the program enabled. This is approximately $200 million per year in lost revenue every year to save $450 million over 25 years. Lost revenue puts undue pressure on rate and jeopardizes the legislated requirement of low and stable rates.

We also object to the use of 100% debt financing for the WACC in the strategist software. NB Power should be using the actual capital structure in their modeling and using 0% ROI for their equity.

If NB Power would like to optimize the Carbon Tax and Investment plan we have submitted we recommend that NB Power use a WACC of 0% in their strategist software.

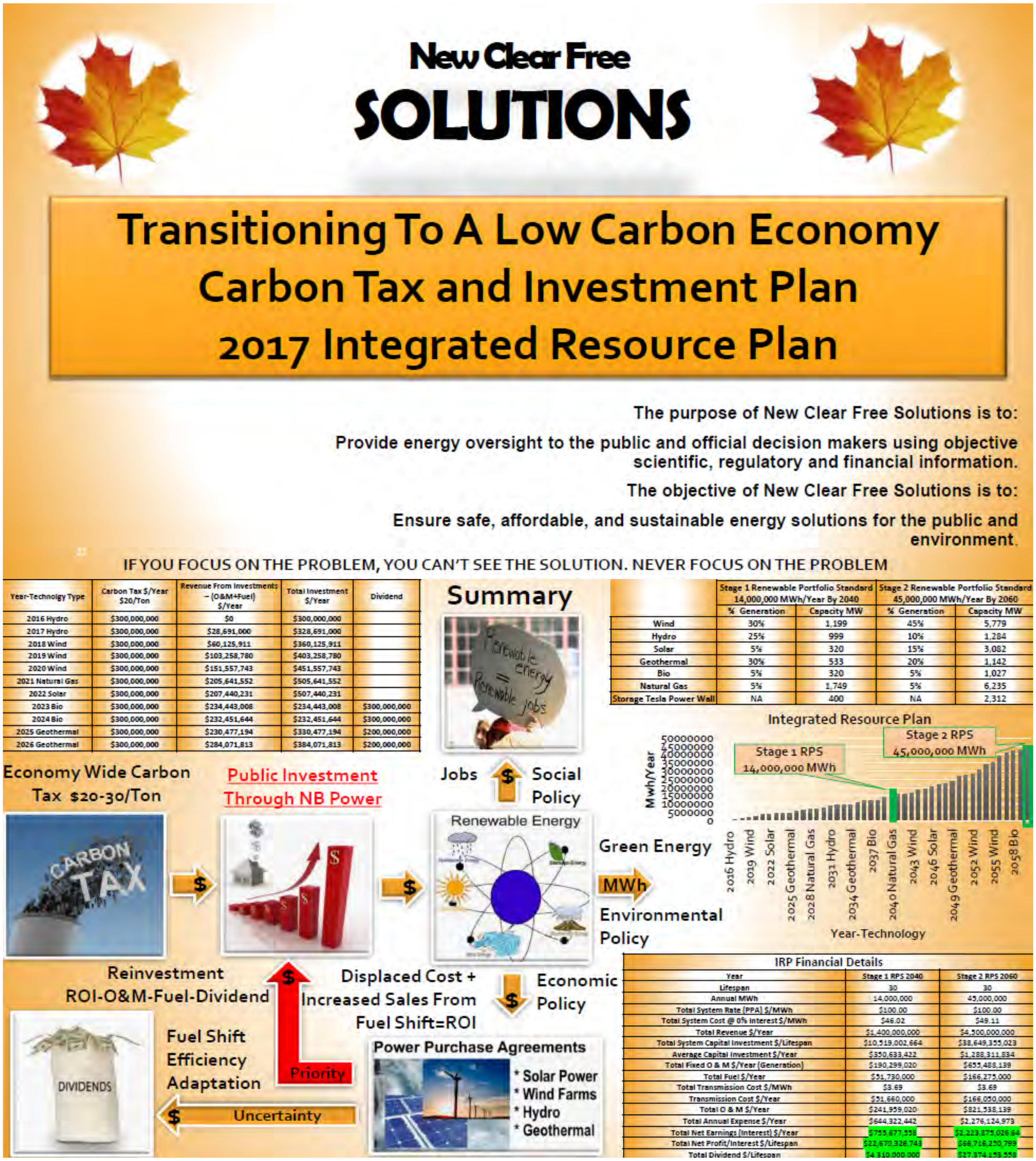
We strongly object to the focus on debt repayment. Even NB Powers own economic expert agreed that debt repayment should only be done with any money that is left over. Debt repayment is the tail wagging the dog. NB Power has a legislated equity target and not a debt reduction target. There should be no focus on debt repayment. NB Powers current focus should be return on investment. Our largest financial risk in the province is the performance of Point Lepreau and debt repayment does nothing to mitigate this risk. We risk paying down a bunch of debt to build equity then losing all the equity when Lepreau has to be shut down for one reason or another or our coal plant has to be shut down. Paying down debt is essentially investing in the bad past investments that NB Power has made that are causing all the risk.

Thank you for this opportunity to submit our thoughts on NB Powers future.

Regards

Chris Rouse

New Clear Free Solutions



New Clear Free SOLUTIONS

Transitioning To A Low Carbon Economy
Carbon Tax and Investment Plan
2017 Integrated Resource Plan

The purpose of New Clear Free Solutions is to:

Provide energy oversight to the public and official decision makers using objective scientific, regulatory and financial information.

The objective of New Clear Free Solutions is to:

Ensure safe, affordable, and sustainable energy solutions for the public and environment.

IF YOU FOCUS ON THE PROBLEM, YOU CAN'T SEE THE SOLUTION. NEVER FOCUS ON THE PROBLEM

Year-Technolgy Type	Carbon Tax $/Year $20/Ton	Revenue From Investments – (O&M+Fuel) $/Year	Total Investment $/Year	Dividend
2016 Hydro	$300,000,000	$0	$300,000,000	
2017 Hydro	$300,000,000	$28,691,000	$328,691,000	
2018 Wind	$300,000,000	$60,125,911	$360,125,911	
2019 Wind	$300,000,000	$103,258,780	$403,258,780	
2020 Wind	$300,000,000	$151,557,743	$451,557,743	
2021 Natural Gas	$300,000,000	$205,641,552	$505,641,552	
2022 Solar	$300,000,000	$207,440,231	$507,440,231	
2023 Bio	$300,000,000	$234,443,008	$234,443,008	$300,000,000
2024 Bio	$300,000,000	$232,451,644	$232,451,644	$300,000,000
2025 Geothermal	$300,000,000	$230,477,194	$330,477,194	$200,000,000
2026 Geothermal	$300,000,000	$284,071,813	$384,071,813	$200,000,000

Summary

	Stage 1 Renewable Portfolio Standard 14,000,000 MWh/Year By 2040		Stage 2 Renewable Portfolio Standard 45,000,000 MWh/Year By 2060	
	% Generation	Capacity MW	% Generation	Capacity MW
Wind	30%	1,199	45%	5,779
Hydro	25%	999	10%	1,284
Solar	5%	320	15%	3,082
Geothermal	30%	533	20%	1,142
Bio	5%	320	5%	1,027
Natural Gas	5%	1,749	5%	6,235
Storage Tesla Power Wall	NA	400	NA	2,312

IRP Financial Details		
Year	Stage 1 RPS 2040	Stage 2 RPS 2060
Lifespan	30	30
Annual MWh	14,000,000	45,000,000
Total System Rate (PPA) $/MWh	$100.00	$100.00
Total System Cost @ 0% Interest $/MWh	$46.02	$49.11
Total Revenue $/Year	$1,400,000,000	$4,500,000,000
Total System Capital Investment $/Lifespan	$10,519,002,664	$38,649,355,023
Average Capital Investment $/Year	$350,633,422	$1,288,311,834
Total Fixed O & M $/Year (Generation)	$190,299,020	$655,488,139
Total Fuel $/Year	$51,730,000	$166,275,000
Total Transmission Cost $/MWh	$3.69	$3.69
Transmission Cost $/Year	$51,660,000	$166,050,000
Total O & M $/Year	$241,959,020	$821,538,139
Total Annual Expense $/Year	$644,322,442	$2,276,124,973
Total Net Earnings (Interest) $/Year	$755,677,558	$2,223,875,026.64
Total Net Profit/Interest $/Lifespan	$22,670,326,743	$66,716,250,799
Total Dividend $/Lifespan	$4,310,000,000	$27,374,153,558

Carbon Tax and Investment Plan Features

- Taxes the Problem and invests in the solutions
- Fully integrated plan for all sectors
- Creates much needed jobs in a multi-decade construction boom
- Compound interest is fueled with savings from displacing fossil fuels and purchased power and increased sales from fuel switching of the industrial heat and steam and automotive sectors to electricity.
- Lowest cost policy option and not dependant on the technology mix (Technology Neutral)
- Freezes electricity rates well into the future and is less than the current business as usual rate increases being proposed by NB Power (lower cost than doing nothing)
- Transition to debt free NB Power (Currently 95% in debt)
- No early retirement for existing power plants (No Premature Job Losses)
- Focuses on displacing fossil fuels not fossil fuel capacity. (Capacity doesn't emit CO_2 and fixed O and M is a small cost) This also addresses what happens when the wind doesn't blow.
- Significant new source of revenue for province. ($1 to $2 Billion Per Year for NB)
- Prioritizes Investments over subsidises/incentives
- Focuses on the efficiency gains in the transition of industrial heat and steam and transportation sectors. Reducing electricity usage has little environmental impacts and significant detrimental economic consequences.
- Minimal behavioural changes, focuses on transition from dirty energy to clean energy
- Fuels economic growth during multi decade construction boom
- Guaranteed to work if the policy is adhered too. All variables affect only "when" the objective is achieved not "if" the objective is achieved

Carbon Tax and Investment Plan

UNBSJ Professor of Economics, Dr. Rob Moir. "The concept of reinvesting in environmentally-friendlier energy production and energy efficiency to create a compound interest effect is founded economic theory. As such this policy should be considered by all provinces and not only New Brunswick."

Amount

rate of interest

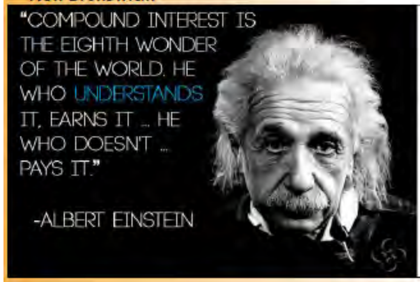
$$\boxed{A = P\left(1+\frac{r}{n}\right)^{nt}}$$

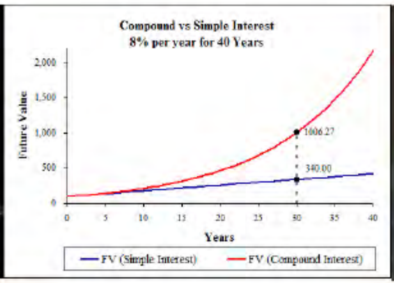
time in years

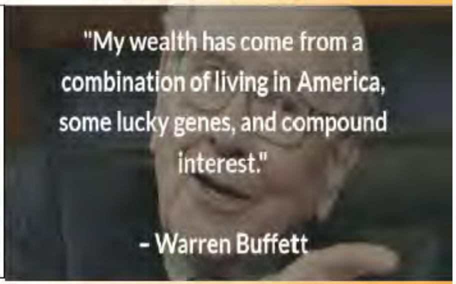
Principal

number of times per year, interest is compounded

NB Power System Planning Engineer Darren Clark: "We reviewed Mr. Rouse's model and functionally I believe the majority of what he is setting out to do, the model is accomplishing."







Modeling Objectives

The general purpose of the modeling is to reasonably demonstrate using todays technology and todays costs and todays rates that New Brunswick can reasonably transition to a low carbon economy by investing the carbon tax into renewable energy and fuel switching technologies such as electrode boilers and electric cars.

Stage 1 Renewable Portfolio Standard (Green The Grid)

The objective of this renewable portfolio standard (RPS) is to green the current "electricity" consumption to 95% renewable by 2040. 2014-2015 was used as the test year for comparison to the business as usual.

Stage 2 Renewable Portfolio Standard (Fuel Shift or Electrification)

The objective of this renewable portfolio standard is shift all remaining fossil fuel usage to 95% green "energy" by 2060 at the same or less cost than the fossil fuel equivalent. Stage 2 does not require the completion of stage 1 before commencing. The transition to stage 2 can begin as long as the fuel switch has a net carbon reduction. This is essentially the electrification of our transportation and industrial heat/steam.

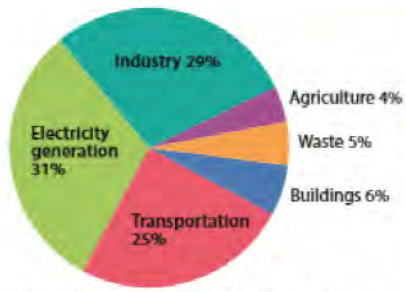
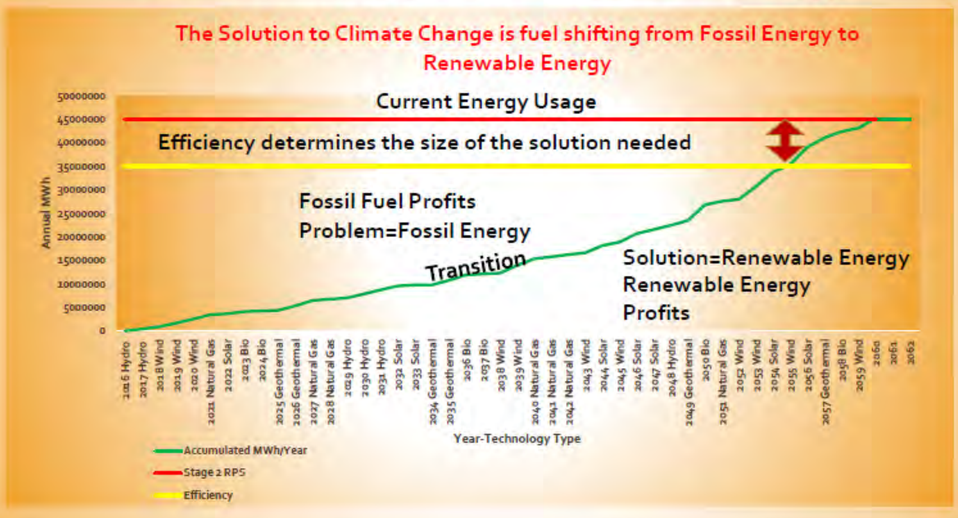


Figure 1: Distribution of GHG emissions in New Brunswick
Source: Environment Canada

The Solution = Renewable Energy



Technical Barriers? NO

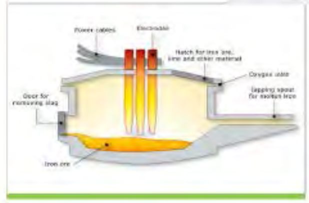
Supply Side

- Hydro
- Wind
- Solar
- Geothermal
- Biofuels
- Smart Grids
- Storage Thermal/Battery
- High Capacity Very Low Capacity Factor FF plants
- Enough Resources

Demand Side

At Least 30% efficiency Gain in Electric Car and Electrode Boilers

- Electrode Boilers
- Electric Cars
- Electric Trains
- Electric Busses
- Electric Arc Furnace
- Heat Pump

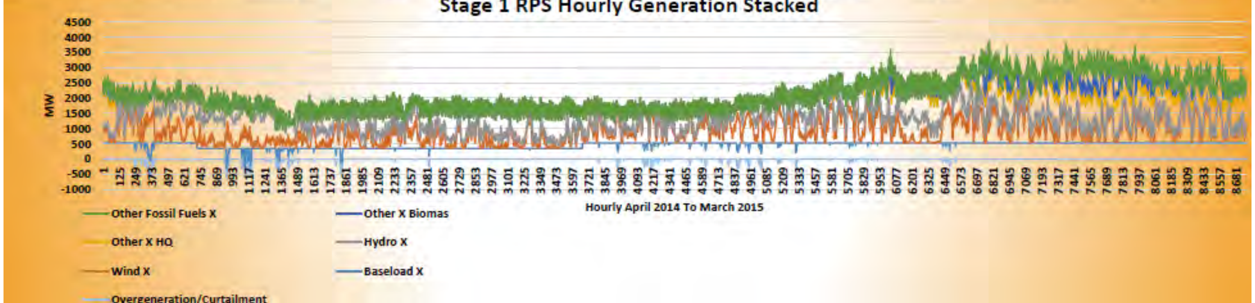


Technology will only get better with time

Stage 1 RPS Investment Details

In Province Generation	% Generation	Capacity MW	Capacity Factor	Capital Cost $/MW	Total Capital Cost $	Total MWh/Year	Fixed O & M $/kw	Total Fixed O & M $/Year	Fuel Cost $/MWh	Total Fuel Cost $/Year
Wind	30.0%	1,168	0.40	$1,664,000	$1,944,372,603	4,094,400	45.98	$53,727,315	0	$0
Hydro	25.0%	974	0.40	$2,411,000	$2,347,697,489	3,412,000	14.7	$14,314,041	0	$0
Solar	0.0%	0	0.25	$2,480,000	$0	0	21.33	$0	0	$0
Geothermal	30.0%	530	0.88	$2,687,000	$1,423,918,864	4,094,400	116.12	$61,535,340	0	$0
Bio	5.0%	330	0.24	$3,765,000	$1,242,761,783	682,400	108.63	$35,856,896	35	$23,884,000
Natural Gas	5.0%	1,604	0.05	$664,000	$1,064,792,792	682,400	6.65	$10,663,964	70	$47,768,000
Hydro Quebec	5.0%	1,000	NA	NA	NA	682,400	NA	NA	38.9	$26,545,360
Storage Tesla Power Wall II		800	NA	$1,600,000	$1,280,000,000	NA	0	$0		
Dividends (Energy Efficiency,Conservation,Fuel Switching, Adaptation)					$4,770,000,000					

Stage 1 RPS Hourly Generation Stacked



Assumptions	Year	Stage 1 IRP 2040	2014-15 NB Power Annual Report
	Business As Usual Comparison		
Based on US Gov EIA Annual Energy Outlook 2016	Lifespan	30	NA
2014-2015 NB Power Annual Report	Annual MWh In Province	13,648,000	13,648,000
2014-2015 NB Power Annual Report	Annual MWh Export	4,575,000	4,575,000
2014-2015 NB Power Annual Report	Total Generation	18,223,000	18,223,000
Stage 1 RPS Mix No Capacity Value for Wind or Solar	Firm Capacity MW	4,237	NA
2014-2015 NB Power Annual Report	Firm Capacity Requirment MW	4,000	4,000
Does not include Interconnects	Total In Province Capacity MW	5,406	NA
Total Annual In Province Revenue Divided by Annual In Province MWh Generation	Total System Rate (PPA) $/MWh	$100.67	$100.67
Total Annual Export Revenue Divided by Annual Export MWh Generation	Export Rate $/MWh	$75.63	$75.63
2014-2015 NB Power Annual Report	Annual Export Revenue	$346,000,000.00	$346,000,000.00
2014-2015 NB Power Annual Report	Annual In Province Revenue $/Year	$1,374,000,000.00	$1,374,000,000.00
2014-2015 NB Power Annual Report	Total Revenue $/Year	$1,791,000,000	1,791,000,000
Total Revenue/Year * Lifespan	Total Revenue $/Lifespan	$53,730,000,000	NA
Calculated Annual Export Cost Divided by Annual MWh Export	Export Total Cost $/MWh	$62.30	$62.30
2014-2015 NB Power Annual Report	Annual Export Cost	$285,000,000.00	$285,000,000.00
Difference between revenue and cost	Export Margin	$61,000,000.00	$61,000,000.00
Total Annual Expense Divided By Total MWh Production Over Lifespan	Total System Cost $/MWh	$77.70	$91.00
Total Capital Investment Stage 1 RPS	Total System Capital Investment $/Lifespan	$9,303,543,531	NA
Straight Line Amortization Over Life of the assets	Depreciation and Amortization Expense $/Year	$310,118,118	$239,000,000
US Gov EIA Annual Energy Outlook 2016 and Energy Mix	Total Fixed O & M $/Year (Generation)	$176,097,556	NA
CTIP uses US Gov EIA Annual Energy Outlook 2016 fuel cost and 2014-2015 NB Power Annual Report	Total Fuel and Purchased Power Including Exports $/Year	$383,197,360	$826,000,000
Based on Total Fuel Cost/Year * Lifespan	Total Fuel $/Lifespan	$11,495,920,800	NA
Approximate cost based on working papers provided by NB Power	Total Transmission/Distribution O&M Cost $/MWh	$14.00	NA
Approximate cost based on working papers provided by NB Power	Transmission And Distribution O&M Cost $/Year	$191,072,000	NA
Based on Total Fixed O & M (Generation)+Transmission Cost/Year	Total O & M $/Year	$367,169,556	$477,000,000
Based on Total O & M/Year * Lifespan	Total O & M $/Lifespan	$11,015,086,676	NA
Based on Total O &M/Year + Total Fuel/Year + Average Capital Investment/Year	Total Annual Expense $/Year	$1,060,485,034	NA
Based on Total Annual Expense/Year * Lifespan	Total Expense $/Lifespan	$31,814,551,006	NA
It is assumed that all of the debt will eventually be paid off, but may not be untill after the transition is complete.	Debt to Equity Ratio	0:100	96:4
Based on 2015 NB Power Annual Report	Financing Cost/Interest	$0	$229,000,000
2014-2015 NB Power Annual Report	Taxes	$37,000,000	$37,000,000
It is assumed that all of the debt will eventually be paid off, but may not be untill after the transition is complete.	Net Debt	$0	$4,913,000,000
CTIP does not include infationary Increases, while the NB Power 10 Year Plan does.	Rate Increases	4-5% Once	2% Annually Forever
Based on Total Revenue/Year - Total Annual Expense/Year	Total Net Earnings (Interest) $/Year	$693,514,966	$73,000,000
Based on Total Net Earnings * Lifespan	Total Net Profit/Interest $/Lifespan	$20,805,448,994	NA
Based on Integrated Resource Plan.	Total Dividends Paid during IRP	$4,770,000,000	NA

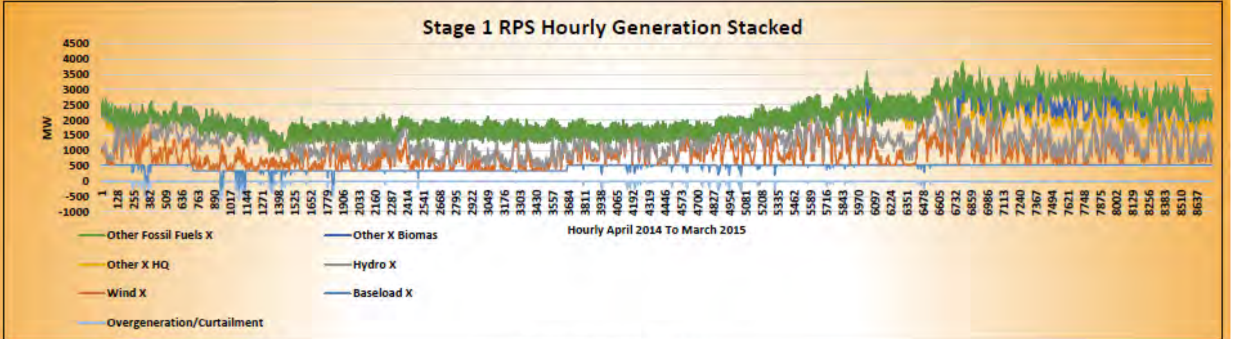
Integrated Resource Plan Blue=Calculated Yellow=Policy Grey=Cost and Performance Data US Government 2016 Energy Outlook.

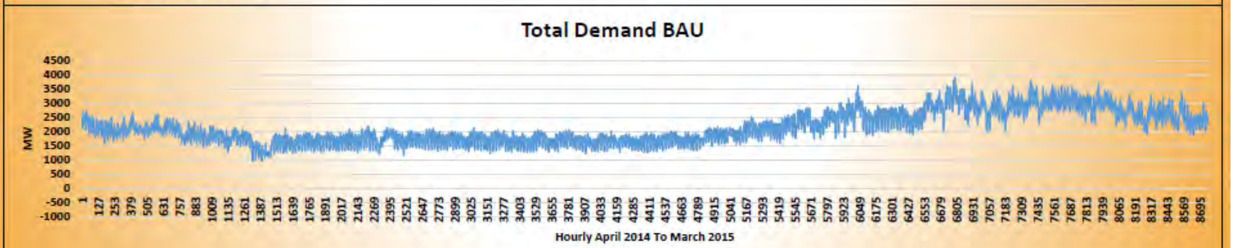
Year-Technolgy Type	Accumulated MWh/Year	Carbon Tax $/Year $24/Ton	Accumulated Reinvestent $/Year	Total Investment $/Year	Dividend/Investment Energy Efficiency/ Mitigation	Technology Type Stage 1	Capacity Factor	In Service Capital Cost	Fixed O & M $/kw	Fuel Cost $/MWh	Capacity MWh	Total Fixed O & M $/Year	Total Fuel Cost $/Year	Generation MWh/Year	Income From Investment	PPA $/MWh	Income Minus (O & M + Fuel)
2016 Hydro	0	$370,000,000	$0	$370,000,000		Hydro	0.40	$2,411,000	14.7	0	153	$2,255,910.41	$0	537,735	$26,349,034	49	$24,093,123
2017 Hydro	537,735	$370,000,000	$24,093,123	$394,093,123		Hydro	0.40	$2,411,000	14.7	0	163	$2,402,807.51	$0	572,751	$28,064,792	49	$25,661,984
2018 Wind	1,110,486	$370,000,000	$49,755,107	$369,755,107	$50,000,000	Wind	0.34	$1,664,000	45.98	0	222	$10,217,151.35	$0	661,826	$32,429,478	49	$22,212,327
2019 Wind	1,772,312	$370,000,000	$71,967,434	$391,967,434	$50,000,000	Wind	0.34	$1,664,000	45.98	0	236	$10,830,927.06	$0	701,584	$34,377,617	49	$23,546,690
2020 Wind	2,473,896	$370,000,000	$95,514,124	$415,514,124	$50,000,000	Wind	0.34	$1,664,000	45.98	0	250	$11,481,574.18	$0	743,730	$36,442,786	49	$24,961,212
2021 Natural Gas	3,217,627	$370,000,000	$120,475,336	$340,475,336	$150,000,000	Natural Gas	0.04	$664,000	6.65	70	513	$3,409,881.00	$12,577,077	179,673	$8,803,954	49	-$7,183,004
2022 Geothermal	3,397,299	$370,000,000	$113,292,332	$293,292,332	$190,000,000	Geothermal	0.90	$2,687,000	116.12	0	109	$12,674,769.49	$0	860,557	$42,167,295	49	$29,492,525
2023 Bio	4,257,856	$370,000,000	$142,784,857	$212,784,857	$300,000,000	Bio	0.25	$3,765,000	108.63	35	57	$6,139,394.17	$4,331,995	123,771	$6,064,792	49	-$4,406,596
2024 Wind	4,381,627	$370,000,000	$138,378,261	$208,378,261	$300,000,000	Wind	0.34	$1,664,000	45.98	0	125	$5,757,952.18	$0	372,977	$18,275,875	49	$12,517,923
2025 Wind	4,754,605	$370,000,000	$150,896,184	$217,896,184	$303,000,000	Wind	0.34	$1,664,000	45.98	0	131	$6,020,953.45	$0	390,013	$19,110,648	49	$13,089,694
2026 Geothermal	5,144,618	$370,000,000	$163,985,878	$333,985,878	$200,000,000	Geothermal	0.90	$2,687,000	116.12	0	124	$14,433,360.70	$0	979,957	$48,017,897	49	$33,584,536
2027 Bio	6,124,575	$370,000,000	$197,570,414	$567,570,414	$0	Bio	0.25	$3,765,000	108.63	38.9	151	$16,375,876.26	$12,842,468	330,141	$16,176,887	49	-$13,041,457
2028 Wind	6,454,715	$370,000,000	$184,528,958	$354,528,958	$200,000,000	Wind	0.34	$1,664,000	45.98	0	213	$9,796,419.16	$0	634,573	$31,094,065	49	$21,297,645
2029 Hydro	7,089,288	$370,000,000	$205,826,603	$506,826,603	$69,000,000	Hydro	0.40	$2,411,000	14.7	0	210	$3,090,149.76	$0	736,591	$36,092,949	49	$33,002,799
2030 Hydro	7,825,879	$370,000,000	$238,829,403	$539,829,403	$69,000,000	Hydro	0.40	$2,411,000	14.7	0	224	$3,291,369.65	$0	784,555	$38,443,197	49	$35,151,828
2031 Hydro	8,610,434	$370,000,000	$273,981,230	$574,981,230	$69,000,000	Hydro	0.40	$2,411,000	14.7	0	238	$3,505,692.28	$0	835,643	$40,946,486	49	$37,440,794
2032 Natural Gas	9,446,077	$370,000,000	$311,422,024	$381,422,024	$300,000,000	Natural Gas	0.04	$664,000	6.65	70	574	$3,819,964.55	$14,089,638	201,281	$9,862,746	49	-$8,046,856
2033 Geothermal	9,647,357	$370,000,000	$303,375,168	$73,375,168	$600,000,000	Geothermal	0.90	$2,687,000	116.12	0	27	$3,170,943.26	$0	215,292	$10,549,312	49	$7,378,369
2034 Natural Gas	9,862,649	$370,000,000	$310,753,537	$180,753,537	$500,000,000	Natural Gas	0.04	$664,000	6.65	70	272	$1,810,257.56	$6,676,992	95,386	$4,673,894	49	-$3,813,355
2035 Geothermal	9,958,035	$370,000,000	$306,940,182	$26,940,182	$650,000,000	Geothermal	0.90	$2,687,000	116.12	0	10	$1,164,232.94	$0	79,046	$3,873,250	49	$2,709,017
2036 Bio	10,037,081	$370,000,000	$309,649,199	$79,649,199	$600,000,000	Bio	0.25	$3,765,000	108.63	35	21	$2,298,085.66	$1,621,543	46,330	$2,270,161	49	-$1,649,468
2037 Bio	10,083,411	$370,000,000	$307,999,731	$227,999,731	$450,000,000	Bio	0.25	$3,765,000	108.63	35	61	$6,578,382.67	$4,641,748	132,621	$6,498,447	49	-$4,721,684
2038 Geothermal	10,216,032	$370,000,000	$303,278,047	$623,278,047	$50,000,000	Geothermal	0.90	$2,687,000	116.12	0	232	$26,935,261.19	$0	1,828,777	$89,610,079	49	$62,674,818
2039 Wind	12,044,809	$370,000,000	$365,952,865	$435,952,865	$300,000,000	Wind	0.34	$1,664,000	45.98	0	262	$12,046,341.78	$0	780,314	$38,235,372	49	$26,189,030

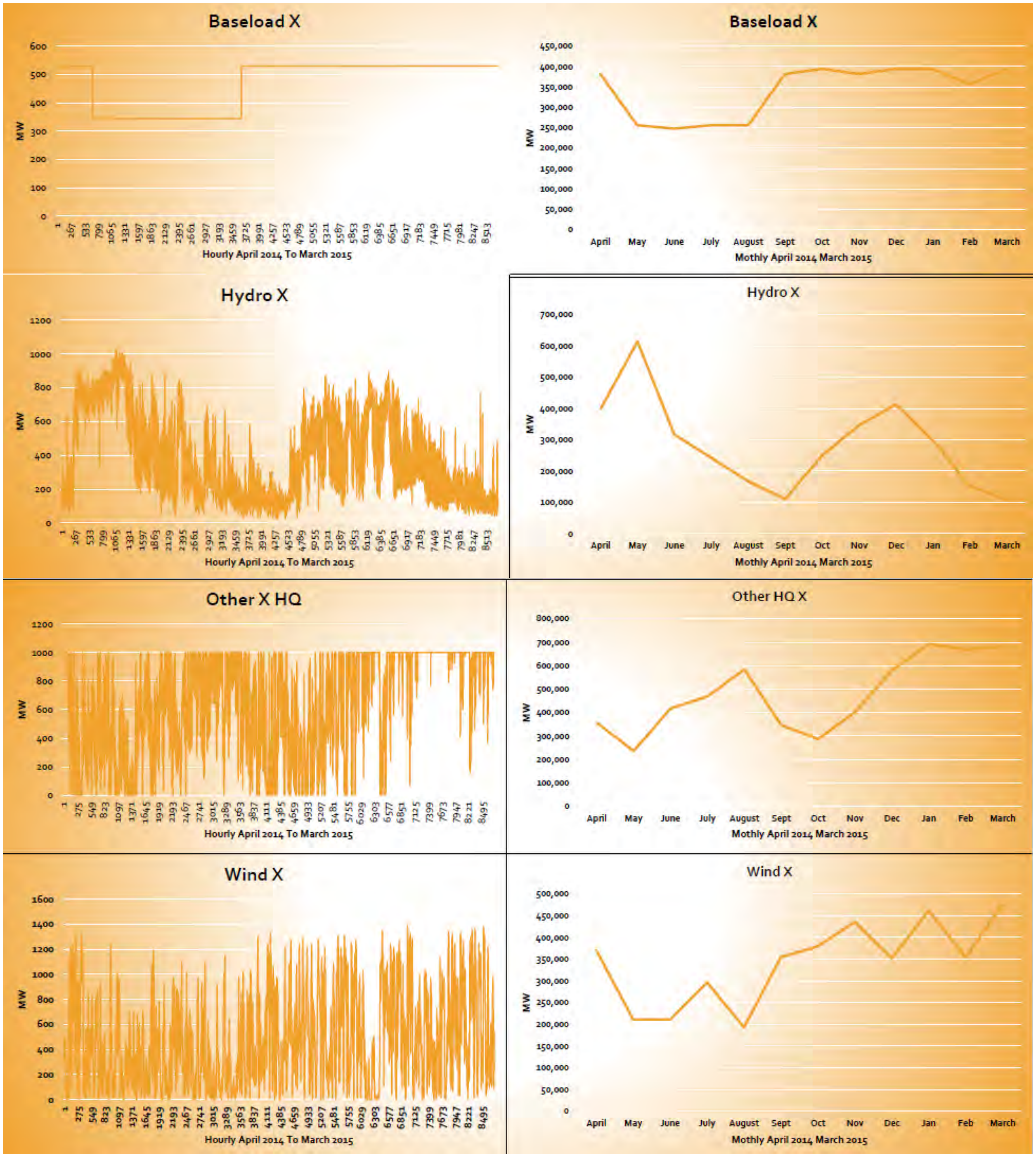
Sensitivity Analysis

Sensitiviity Case	Base Case Net Earnings	Business As Usual Net Earnings	Plus 10%-Net Earnings	Minus 10%-Net Earning	Plus 10% Difference From Base Case	Minus 10% Difference From Base Case
Captial Cost	$693,514,966	$73,000,000	$662,503,155	$724,526,778	-$31,011,812	$31,011,812
Wind Capacity Factor	$693,514,966	$73,000,000	$704,291,306	$680,343,885	$10,776,340	-$13,171,082
Fixed O and M	$693,514,966	$73,000,000	$675,905,211	$711,124,722	-$17,609,756	$17,609,756
Fuel Cost	$693,514,966	$73,000,000	$683,695,230	$703,334,702	-$9,819,736	$9,819,736
Lifespan	$693,514,966	$73,000,000	$721,707,523	$659,057,398	$28,192,556	-$34,457,569
Demand	$693,514,966	$73,000,000	$762,208,949	$624,781,097	$68,693,982	-$68,733,869
Rates	$693,514,966	$73,000,000	$830,894,486	$556,023,766	$137,379,520	-$137,491,200
Best/Worst Case Scenario	$693,514,966	$73,000,000	$514,259,696	$863,011,068	-$179,255,271	$169,496,101

Demand and Rates have the largest effects on the plan. Reducing Demand has significant impacts on the financial health of NB Power and generally lower demand = increase in rates. We strongly disagree with the reduce part of the RASD program at this current time.






Baseload X
MW
Hourly April 2014 To March 2015
Baseload X
MW
Mothly April 2014 March 2015
April May June July August Sept Oct Nov Dec Jan Feb March
Hydro X
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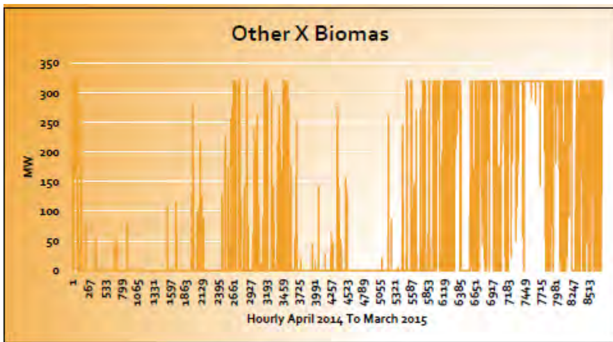
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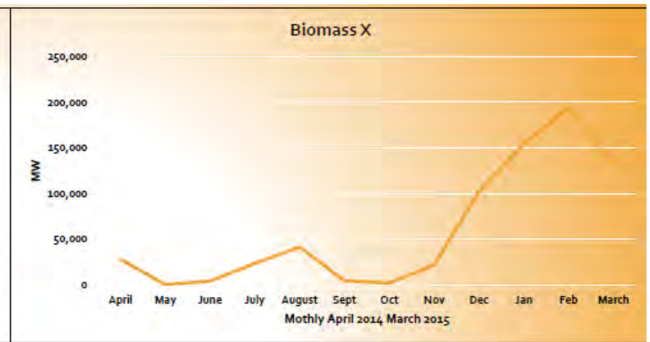
Hourly April 2014 To March 2015


Biomass X
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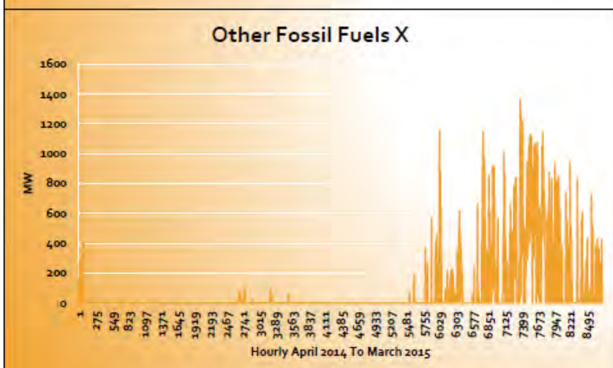
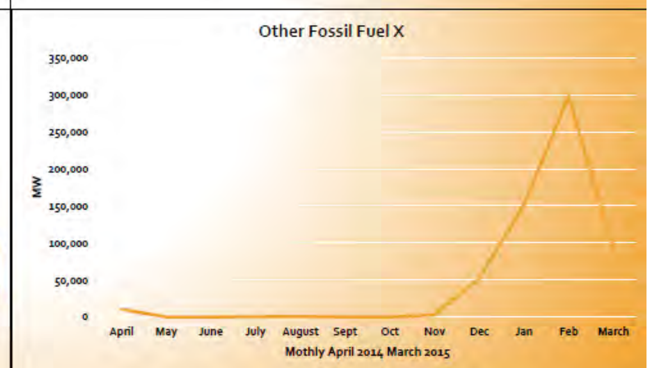
Mothly April 2014 March 2015


Other Fossil Fuels X
MW
Hourly April 2014 To March 2015


Other Fossil Fuel X
MW
April
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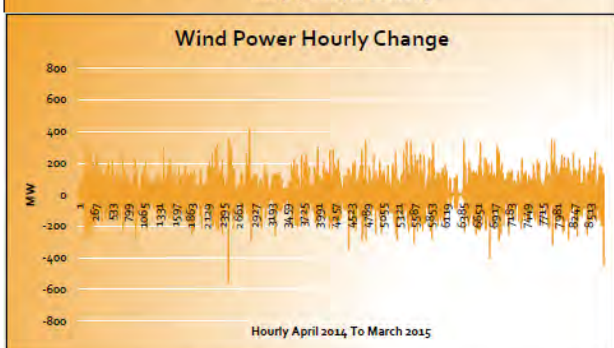
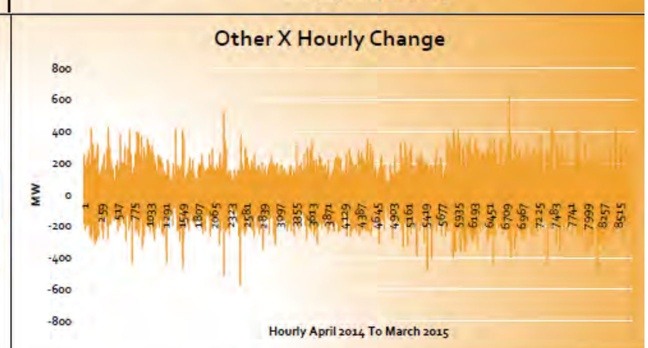
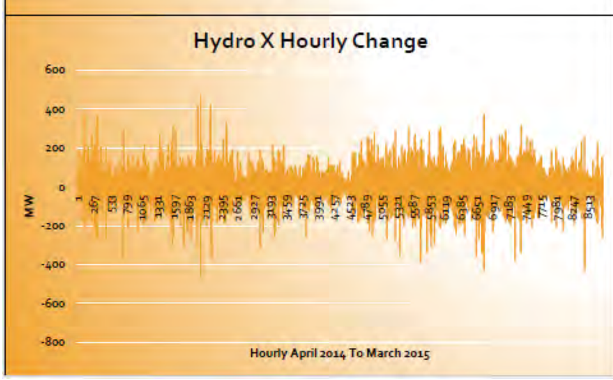
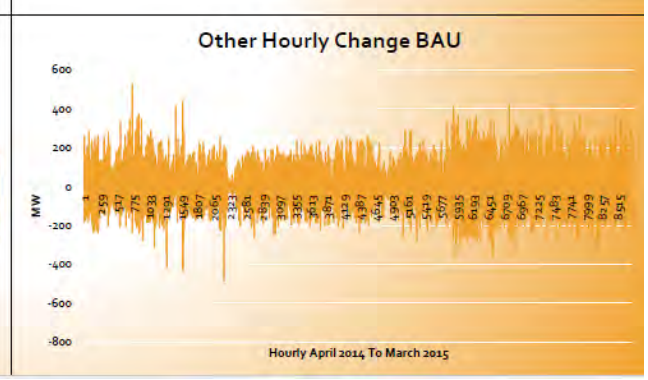
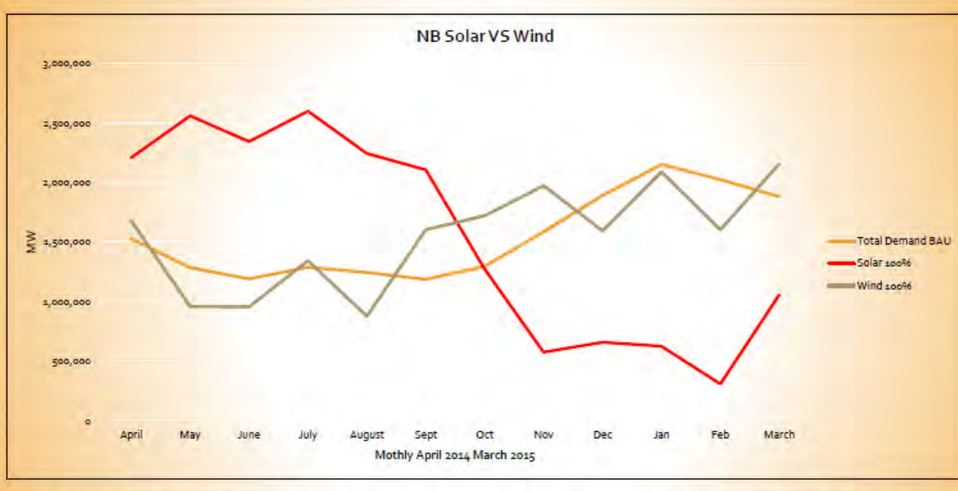
March
Mothly April 2014 March 2015


Wind Power Hourly Change
MW
Hourly April 2014 To March 2015


Other X Hourly Change
MW
Hourly April 2014 To March 2015


Hydro X Hourly Change
MW
Hourly April 2014 To March 2015


Other Hourly Change BAU
MW
Hourly April 2014 To March 2015



The above graph uses actual monthly Wind and Solar profiles scaled up to be 100% of our current usage. Please note that wind power closely matches our current energy usage while solar is opposite. It is much easier to integrated resources who's profiles closely match our usage. Hot climates generally will use more solar while colder northern climates more wind.

Hon. Donald Arseneault
Minister of Energy and Mines
PO Box 6000
Fredericton, NB, E3B 5H1
tyler.campbell@gnb.ca

Dear Minister and subsequent ministers of the Province of New Brunswick:

We are a group of 12 New Brunswick citizens randomly selected as part of a research project at the University of New Brunswick. The group deliberated over the weekend of October 3 and 4, 2015, to develop a 25-year electrical energy vision for the province.

We believe that there is a strong and immediate need for action on climate change and effort is needed toward the reduction of greenhouse gas emissions. Specifically, we are interested in the integration of renewable systems such as hydro, solar, wind, tidal, and biomass, while minimizing the use of non-renewable resources.

We respectfully present the following recommendations to maintain an affordable and renewable energy system, progressively built into the retirement of current assets over time.

- All major policy decisions regarding the future of the electricity systems should be open and transparent.
- Partnering and sharing assets with the Atlantic region (including options south of the border) will improve efficiency and reliability of the system.
- Grid reliability can be improved by including small sustainable systems to provide more flexibility.

The consensus of the committee is to establish pilot projects to implement these system changes, by setting up studies in the municipalities, including solar, wind, home-based energy systems, and consideration for electric cars (for example, the Halifax Solar City and Property Assessment Clean Energy program). We believe the benefits of this program will include employment, high skilled jobs, local training and will keep our youth in the province.

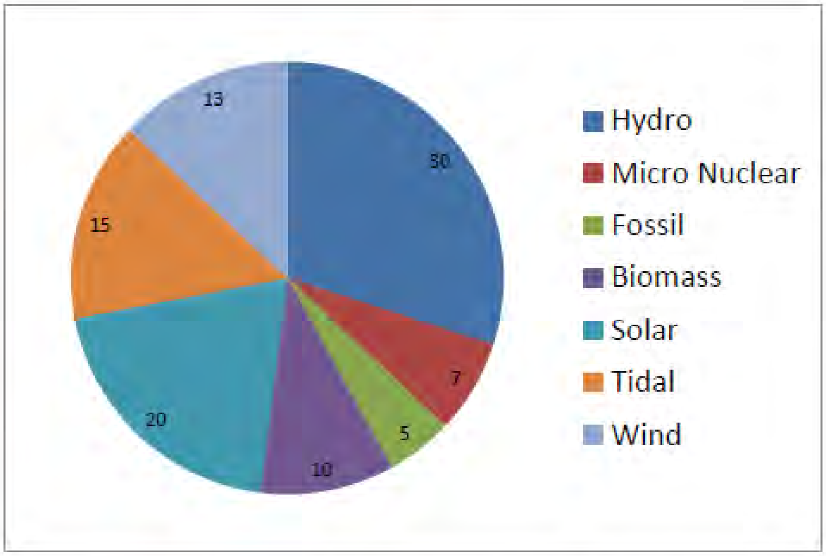
The size of the system will ultimately be affected by greater efficiency in the current system and electrification to support non-fossil fuel based transportation technologies. We also recognize there will be great gains made by energy saving technologies including reducing and shifting demand.

We have taken into consideration concerns for sustainability, climate change, cost effectiveness, and we are sensitive to the continuity and the reliability of the current electrical infrastructure in the Province of New Brunswick.

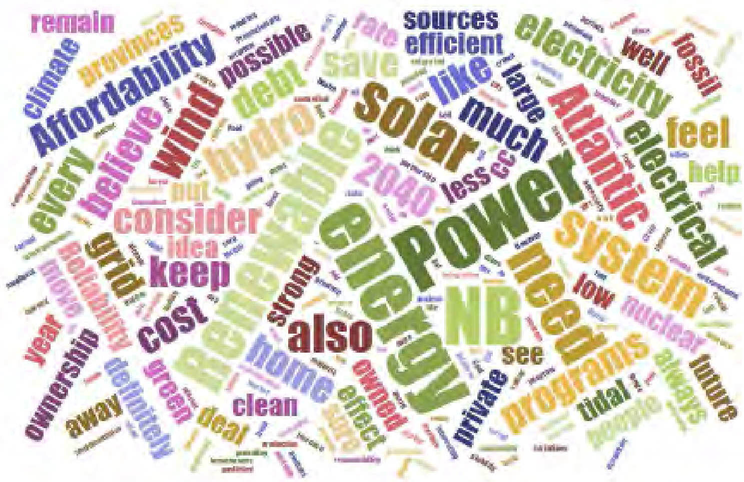
Sincerely,

The Deliberating Members of the New Brunswick Electrical Energy Futures Jury

cc: Gaeton Thomas, President and CEO, NB Power, gathomas@nbpower.com



Pie chart representing the consensus of the deliberating Members of the New Brunswick Electrical Energy Futures Jury on the 2040 fuel mix. The group began with a figure containing equal sized pie wedges for each of the seven categories of electrical energy generation and then negotiated this final graphic through a consensus process.



Word cloud representing a graphic summary of themes and topics of concern to participants. The data from the word cloud were drawn from paragraphs written by the Members of the New Brunswick Electrical Energy Futures Jury and the size of the font for each word represents the frequency that word was mentioned. The end result gives a graphic depiction of the attributes of the electrical energy system in 2040 that they felt will be most important to most New Brunswickers.

Conservation Council *of* New Brunswick
Conseil de conservation *du* Nouveau-Brunswick
www.conservationcouncil.ca

May 16, 2017

Mr. Gaëtan Thomas
CEO, NB Power
515 King Street
Fredericton, NB
E3B 4X1

Re: Comments on 2017 Integrated Resource Plan

Dear Mr. Thomas:

Thank you for the opportunity to provide input on NB Power's 2017 Integrated Resource Plan (IRP). The Conservation Council believes New Brunswick, and NB Power, have an important opportunity to create a clean electricity system in line with national and international climate change commitments, that improves the health and well-being of ratepayers, and that creates long-term sustainable jobs in our province. We believe we can achieve these objectives while maintaining reliability and managing rate impacts. Before summarizing the menu of options to consider, let's set the table by summarizing the context within which IRP planning is taking place.

Since the 2014 IRP, significant changes have occurred in the policy landscape with the 2016 national Pan-Canadian Framework resulting from the 2015 United Nations Paris Agreement being one of the most significant. NB Power must now explicitly plan for an electricity system operating under a nationally coordinated carbon price, as well as regulations aimed at significantly reducing greenhouse gas emissions intensity of coal-fired power plants. While questions remain with respect to how carbon pricing and coal-fired power plant regulations will be fully implemented, we know enough now to say that NB Power and the Province of New Brunswick should plan for a fossil-fuel free electricity system by 2030.

We also know from the response of New Brunswickers to the proposed sale of NB Power to Hydro Québec that ratepayers/citizens want their electricity produced in New Brunswick by New Brunswickers for New Brunswickers. Ratepayers/citizens also want reasonable power rates and electricity that is reliable. We know clearly from the 2017 ice storm on the Acadian Peninsula, as well as post-tropical storm Arthur, that reliability is not a certainty

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UN Global 500 Roll of Honour Laureate
Lauréat du Club global 500 de l'ONU

with increasing exposure to extreme events and that power outages of a week or more is dangerous to public health.

NB Power argues that it is changing its culture to adapt to changing electricity market conditions, including the transition to significantly more electricity generated from smaller-scale, distributed renewable energy. Its commitment to Smart Grid technologies and to reduce and shift demand initiatives are positioned as evidence of cultural change within NB Power and an openness to developing a new business model. The Conservation Council is concerned that NB Power is not adapting quickly enough to changing conditions. We recommend an offensive, rather than defensive IRP, setting a clear direction toward a fossil-free electricity system by 2030.

Such a commitment would, for example, direct attention away from weakening proposed implementation of federal regulations affecting Belledune, and instead, would focus on transitioning the plant off coal by 2030 and the region toward a renewable, distributed and resilient electricity system in the Acadian Peninsula. Such an approach could ensure a just transition for Belledune workers, create jobs in Northern NB, and allow for federal-provincial partnerships that position our province, in the longer-term, to provide power in NB, for NB, produced by New Brunswickers.

We recommend that the IRP, should be positioned as an electrification strategy for the province, and include commitments to:

1. An economy-wide investment in energy efficiency through building retrofits in social housing, the residential, commercial/institutional/government (including municipal), and industrial sectors; and equipment and appliances. The goal would be to **advance NB Power's Reduce and Shift Demand objective of 609 MW by 2038 to between 2020 and 2025**[1].
2. **Accelerate investments in the Smart Grid** (the Energy Internet) to give the electricity system the capacity it needs to significantly increase the supply of renewable energy (aiming for 100% renewable). The Smart Grid is central to managing a more distributed energy system, as well as providing load balancing services to Nova Scotia, PEI and New England. The electrification strategy, or roadmap, can build on work completed under the Atlantic Energy Gateway Initiative and take advantage of new federal support aimed at identifying opportunities for regional electricity cooperation[2]. Our electrification roadmap needs to be regionally focused, particularly because Nova Scotia will also need to reduce and then phase out the use of coal, and include a regional and long-term system investment plan (i.e. modernizing and

[1] https://www.nbpower.com/media/102794/irpjuly2014-english.pdf, p.128

[2] http://www.acoa-apeca.gc.ca/eng/publications/ResearchStudies/Pages/Home.aspx#aeg; Federal budget 2016 provided $5 million over two years to engage provinces and utilities in assessing regional electricity cooperation opportunities

integrating regional transmission networks, as well as regional targets for renewable energy to replace the loss of coal-fired generation. Acceleration of Smart Grid investments could advance installation of additional renewable energy technologies along with installation of next generation meters, hot water heaters and storage devices using telecommunications systems to manage a distributed load (including micro-grids; beyond what is already currently funded).

3. Expand regional investment in renewable energy, including accelerated solar rooftop targets. **A stretch target for New Brunswick could be 200,000 kilowatts (kW) of cumulative installed commercial and residential solar power by 2025** (100,000 kW each for residential and commercial, grid connected and off-grid), with NB Power working with suppliers to develop home equity loan and/or leasing programs, and power purchase agreements aimed at lowering payback periods from the current 13 to 15 years to between 5 and 10 years.[3]

4. Accelerated scale-up of electricity transportation infrastructure and incentives to increase the sale of electric plug-in and low-emission hybrid vehicles. Québec has a legislated target of putting 100,000 electric vehicles on the road by 2020: that's about 1.2% of the total fleet of over 8 million vehicles registered or about 16% of new car sales in 2020.[4] A similar scheme for New Brunswick would **set a goal of 10,000 electric vehicles on the road by 2020, with the number of electric car sales increasing each year so that by 2030 there would be 140,000 to 150,000 electric vehicles on the road.**[5] A fossil-fuel vehicle driven 20,000 kilometres a year generates about 5 tons of greenhouse gases. A rough estimate of the emissions reduction potential is at least 500,000 tonnes.[6]

5. Community economic development and worker transition investments to maximize job creation from energy efficiency and renewable electricity investments.

Electricity-related investments would be complemented by a provincial investment plan. To see the Conservation Council's full climate action plan, go to: http://www.conservationcouncil.ca/our-programs/climate-and-energy/.

[3] https://www.nbpower.com/media/169863/dsm-plan-2016-18.pdf; represents stretch target for achievable potential

[4] http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ58a-eng.htm; assuming at 50,000 new car sales a month = 600,000 a year so 100,000 electric vehicles in 2020 would be equivalent to at least 16% of all new sales

[5] Assuming at 5,000 new car sales a month or 60,000 a year that 16% would be 9600 vehicles so rounding to 10,000

[6] Assuming 2017: 1k, 2018: 2k, 2019: 3k, 2020: 4k (cumulative = 10k), 2021: 6k, 2022-2030: 8k rising to 20k/year for a total of 140,000 to 150,000 electric vehicles on the road and declining greenhouse gas reductions from fleet fuel economy standards.

We also strongly encourage NB Power to more actively consider risks from climate change impacts in its IRP. Our infrastructure and our capacity to respond to these events has not kept pace with the changes in our climate. Individual extreme events need to be understood in the context of a rapidly changing climate. Scientists working on climate change adaptation increasingly urge a move from short-term emergency response to extreme events. Instead, we are being encouraged to move toward long-term risk reduction and preparedness. This change in focus opens the door to considering and planning for the long-term resiliency of New Brunswick communities and families. Solutions with the longer-term lens in focus encourage us to integrate climate change mitigation and climate change adaptation approaches.

The recent ice storm provides an opportunity think about how we can integrate mitigation and adaptation to climate change into electricity planning. We can develop a regional energy plan for the Acadian Peninsula that brings low to non-emitting sources (from wind, solar, hydro, biomass, if sustainably produced) of electricity and Smart Grid/micro-grid infrastructure into the system that also improves resiliency to extreme events. Priority for installation of new energy resilient technologies could be First Responder buildings like fire halls, city halls, and community centres used as warming centres. The shift to energy resiliency would also involve job-creating retrofits of homes in the region (and throughout the province) to improve energy efficiency and to install renewable energy and other modern technologies. A system-based assessment of options would ensure a sustainable energy system for, in the case of this example, the North that situates solutions within our climate change mitigation, as well as adaptation objectives.

The Conservation Council urges NB Power to advance an electrification strategy in its 2017 IRP that would form the basis of federal-provincial negotiations on how carbon pricing revenue and infrastructure dollars could be allocated within the electricity sector. A progressive and forward-looking IRP has the potential to satisfy the requirements for a reliable, cost-effective and sustainable electricity system based on a new model of delivery and financial operations.

We look forward to collaborating with you to make this vision a reality.

Sincerely,

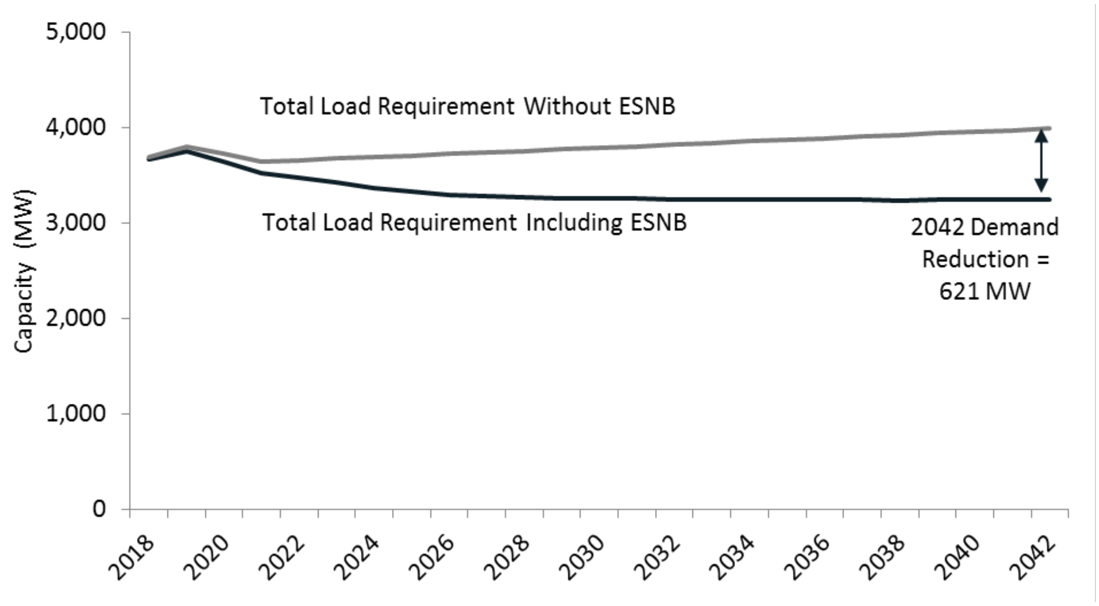
Lois Corbett

Lois Corbett
Executive Director

Appendix 2: List of assumptions for IRP

- **General Inflation**
  - o Assumed 2.0% per year throughout the period.

- **Load Growth**
  - o Based on NB Power's most recent 10-year Load Forecast.
  - o New Energy Smart NB projection determined from the IRP analysis.
  - o Planning reserve requirement of 20% or the largest contingency was applied.



- **Energy Smart NB Impacts**
  - o Energy Smart NB options identified with the assistance of Dunsky Energy Consultants.
  - o Grid modernization projects are forecasted to enable over 200 MW in demand reduction programs.
  - o Two scenarios were provided for Energy Efficiency from Dunsky Energy Consultants. A high energy efficiency scenario will be examined as a sensitivity.
  - o Capital, OM&A and program costs have been updated to reflect the three-year energy efficiency plan and Energy Smart NB budgets.

- **Fuel and Purchased Power**
  - o Fuel and market price forecast in the short-term based on NB Power projections incorporated into the 2017/18 forecast.

  - Long-term fuel and market price projections based on forecasts and analysis provided by (Energy Ventures Analysis Inc.) EVA, an external consultant specializing in this area.
  - Foreign exchange rates based on Bank of Canada Foreign Exchange Forward Curve in the short term (3 years). In the long term, foreign exchange rates are based on long-term historical rates and long term forecasts by the Conference Board of Canada.
  - Energy production from all generating units is determined by economic dispatch to meet in-province load requirements.
  - Short-term interconnection purchases are made available when generating unit dispatch prices exceed forecasted market prices.

- **New Supply**
  - New supply options and costs refreshed by Hatch Engineering in Nov 2016.
  - Supply options included conventional and renewable alternatives.
  - Screening analysis performed using levelized cost methodology to determine cost effectiveness and feasibility.

- **Locally-owned Renewable Energy Projects that are Small Scale (LORESS) and Embedded Generation Programs**
  - 80 MW of renewable energy from LORESS program is assumed to be online in 2020/21.
  - An additional 13 MW of renewable embedded generation is expected to be added by 2020/21.

- **Existing Plant and Power Purchase Agreements End of Life**
  - Belledune generating station operating life is assumed to March 2040. This includes additional costs associated with life extension.
  - Coleson Cove generating station operating life is assumed to April 2040. This includes additional costs associated with life extension.
  - The end of operating life for remaining generating assets are assumed as follows:
    - Millbank and Ste. Rose – November 2030 (25 year life extension option is made available and based on March 2013 discussion paper by Generation Engineering)
    - Point Lepreau – December 2039
      - Capacity and energy assumed to be replaced in kind to maintain 75% non-emitting target and for security of supply
    - Mactaquac Generating Station will be life extended and during the period Jan 2027 – Dec 2032, only 5 of 6 units will be available, lowering the available capacity with a slight reduction to annual production. Additional

engineering is ongoing and this schedule will be finalized as these studies approach completion.
    - Other existing hydro facilities assumed to be replaced in kind
- Power Purchase Agreement (PPA) with Bayside is assumed to end in March 2026.
- PPA with Grandview is assumed to end November 2024.
- Renewable energy PPAs located at Large Industrial customer sites are assumed to persist through the forecast period.
- Wind PPAs renewed for an additional term at reduced prices.

Retirement summary

Nov 2024	Grandview (95 MW)	Retired at end of PPA
Sep 2025	Grand Manan (26 MW)	Retirement
Mar 2027	Bayside (277 MW)	Retired at end of PPA
Jan 2027 to Dec 2033	Mactaquac (672 MW)	Extension to 2068
Nov 2030	Millbank/Ste Rose (496 MW)	25-year extension option
Nov 2039	Lepreau (660 MW)	Capacity and Energy replaced in-kind
Apr 2040	Coleson (972 MW)	Retirement
Mar 2040	Belledune (467 MW)	Retirement

- **Greenhouse Gas Regulation and Prices**
    - Proposed federal performance standards applied to new and existing refurbished coal plants.
    - Existing coal plants are assumed to operate to their end of operating life without penalty.
        - This includes ceasing to use petcoke at Coleson 3 in June 2029.
    - Federal Carbon pricing legislation is included as a sensitivity.

- **Major Capital Expenditures**
    - Grand Falls expansion is not required to meet Renewable Portfolio Standard requirements. In service costs are estimated at approximately $450 million (2017$). This project will be selected if it is an economic supply choice.
    - In-Service costs for Mactaquac Life Achievement are assumed at approximately $1.8 ($2017).
    - The major capital costs to extend the lives of Belledune and Coleson Cove were estimated to be $66 million and $63 million (2017$) respectively. These figures were based on very preliminary engineering estimates. An asset optimization study will be conducted to update these estimates.

- Capital and O&M estimates for new generating supply options provided by Hatch Engineering.
  - Construction price index for new hydro supply options was calculated at 3.2% per year.
  - Construction price index for other new generating supply options was calculated at 3.6% per year.

- **Export Sales**
  - Revenues from MECL continue for participation agreement in Point Lepreau until the end of its life – based on future forecasted costs.
  - Other export load currently held for MECL and Maine was assumed to be maintained.
  - Other opportunity exports were modelled or estimated based upon margins currently generated from existing export load and changes in plant availability in the future.

- **Operations, Maintenance and Administration Costs**
  - Long-term costs escalate at general inflation of 2% per year.
  - OM&A costs for Point Lepreau were modelled to reflect biennial outages.
  - New plants (combustion turbines and natural gas facilities) have operating costs provided by Hatch Engineering, and include OM&A and capital. Amounts for ongoing capital reinvestments have also been included in OM&A.

- **Amortization**
  - The Belledune and Coleson Cove plant costs are amortized over their existing book life and additional expenditures required to extend the life of the plants were recovered over the extension period.
  - The costs of future power plants were amortized over different periods:
    - Wind farms, natural gas plants: 25 years
    - Geothermal and nuclear plants: 30 years
    - Hydro stations: 50 years

- **Deferral Accounts**
  - The Point Lepreau Regulatory Deferral is recovered over the life of the plant.

- **Financing Assumptions**
    - All existing and new supply options assume public financing.
    - Long term financing rate of 5.9% was assumed; 5.25% for debt financing plus the government guarantee fee of 0.65%. This provided for an equivalent weighted average cost of capital (WACC) of 5.9%.
    - An earnings rate of 5% was assumed for the trust funds and the sinking fund held.
    - A discount rate equivalent to the WACC of 5.9% was assumed for all present value analysis.
    - The discount rates for decommissioning and used fuel management liabilities were assumed to be 4-5%.

- **Ratemaking Assumptions**
    - A debt-equity ratio target of 80:20 was assumed to be achieved as per the *Electricity Act* with annual rate increases of 0-2 per cent

Appendix 3: Fuel and Market Price Forecast

	HFO C$Nom/ MMBtu	LFO C$Nom/ MMBtu	Nat Gas Strip C$Nom/ MMBtu	Coal Blend C$Nom/ MMBtu	Coal C$Nom/ MMBtu	Pet-Coke C$Nom/ MMBtu	Nuclear C$Nom/ MMBtu	Mass Hub C$/ MWh
2018	10.50	17.85	9.71	3.78	4.01	3.35	0.513	55.63
2019	10.37	17.66	9.23	3.94	4.05	3.74	0.447	51.29
2020	9.99	17.10	9.38	3.96	4.09	3.73	0.45	51.13
2021	9.75	16.75	10.44	3.97	4.11	3.71	0.455	51.01
2022	10.12	17.38	10.72	3.91	4.04	3.65	0.486	53.83
2023	10.25	17.61	10.67	3.85	3.99	3.6	0.522	56.51
2024	10.27	17.64	10.65	3.78	3.91	3.53	0.557	59.00
2025	10.29	17.67	10.59	3.73	3.86	3.48	0.606	61.28
2026	10.53	18.09	10.82	3.77	3.9	3.52	0.664	62.50
2027	10.75	18.47	11.06	3.81	3.94	3.56	0.711	65.01
2028	10.99	18.88	11.32	3.86	3.99	3.6	0.74	65.62
2029	11.25	19.32	11.59	3.90	4.04	3.65	0.759	67.29
2030	11.52	19.79	11.88	3.96	4.1	3.7	0.781	68.79
2031	11.82	20.31	12.18	4.02	4.16	3.76	0.809	70.33
2032	12.08	20.75	12.50	4.08	4.22	3.81	0.839	72.36
2033	12.36	21.24	12.86	4.14	4.28	3.87	0.869	74.57
2034	12.66	21.74	13.20	4.20	4.35	3.93	0.901	76.37
2035	12.96	22.25	13.61	4.27	4.42	3.99	0.933	78.75
2036	13.26	22.77	14.03	4.33	4.48	4.05	0.968	81.87
2037	13.56	23.30	14.46	4.40	4.55	4.11	1.003	81.97
2038	13.87	23.83	14.92	4.47	4.62	4.17	1.04	84.98
2039	14.17	24.34	15.44	4.54	4.7	4.24	1.078	87.26
2040	14.46	24.83	15.94	4.61	4.77	4.31	1.117	91.67
2041	14.79	25.40	16.42	4.68	4.84	4.37	1.159	94.09
2042	15.13	25.99	16.91	4.75	4.92	4.44	1.201	96.57

Appendix 4: Supply Options

1 CONVENTIONAL SUPPLY OPTIONS

1.1 Nuclear

How is electricity generated using nuclear fuel?
Power is produced from controlled nuclear reactions and the heat generated from the nuclear reactions converts water to pressurized steam, which is then used to generate electricity. According to the World Nuclear Association, about 17 per cent of the electricity generated in Canada came from nuclear power in 2015.

NB Power owns and operates the Point Lepreau Nuclear Generating Station. This station is comprised of one Candu 6 unit constructed during the period 1975-1983 at a cost of approximately $1.4 billion (1983 dollars). The unit was originally designed with a net capacity of 635 MW. The original plans for the facility as developed by Atomic Energy of Canada Limited (AECL) allowed for a two-unit plant.

Following approximately 25 years of operation, a refurbishment project began in 2008 and, after several delays, the unit was returned to service in November 2012. The overall cost of the refurbishment was approximately $2.4 billion (2012 dollars) and is expected to operate for the next 27 years. The refurbished facility is now more efficient and has a net capacity of 660 MW.

Figure 1: The Point Lepreau Nuclear Generating Station

Nuclear Power Plant Development Activities in Canada

Candu Energy Inc. (the private sector company that purchased AECL's generation business) is developing the Advanced Candu Reactor (ACR)–1000 which is described as a generation III+, 1,200 MW heavy water reactor. Design work has advanced to a preliminary stage and the Canadian Nuclear Safety Commission's (CNSC) pre-project design review completed in December 2010 concluded there were no fundamental barriers to licensing the unit in Canada. Ongoing development work on the ACR–1000 has resulted in design changes that have also been applied to the Candu 6 design. The current Candu 6 design is referred to as Enhanced Candu 6 (EC6).

Areva Inc. of France is ranked as the top firm in the global nuclear power industry. The company reported in July 2013 that its ATMEA1 reactor, which it is developing jointly with Mitsubishi Heavy Industries, has passed the first stage of the pre-certification process used by the CNSC. The second and third stages will consist of in-depth analysis of the reactor design in order for the certification process to begin under what it refers to as "the best possible conditions." This reactor has similar features to those of Areva's European Pressurized Reactor (EPR).

In 2009, Ontario received bids from AECL, Areva and Westinghouse Electric for installation of two additional units at Ontario Power Generation's Darlington Nuclear Station. AECL's bid for two 1,200 MW ACR–1000 units to be operational by 2018 was indicated to be the only one of the three bids that was compliant with the terms of the request for proposals. It is reported that the project cost would be approximately $10,800 per kW. The Province of Ontario did not move forward with the project. The Province continues with rehabilitation work on the existing fleet of nuclear generating units.

Nuclear Power Developments in Other Areas

As per the information collected from the World Nuclear Association web site, there currently are 444 reactors operable, 157 reactors in permanent shutdown, two reactors on long-term shutdown and 64 rectors under construction around the world. Among the ones under construction, China, Russia, India and USA have a total of 41. Examples of projects in Finland and the US are discussed below.

Finland currently has two nuclear power plants in service, each with two units, with a total net capacity of some 2,740 MW. These plants typically produce about 30% of the country's annual electricity consumption. In 2002 the country's parliament approved construction of a fifth unit to be in operation by 2009 at the site of one of the existing plants. The owner signed a contract with Areva and Siemens in December 2003 for an EPR reactor with an output of 1,600 MW at a cost of some €3.2 billion. The project has undergone delays and cost overruns and was reported to be more than 80% complete in December 2011. It is reported by the World Nuclear Association that the project will now cost about €8.5 billion ($10,600 per kW) and will not enter commercial operation until December 2018.

There are currently 99 nuclear units operable and five new nuclear units under construction in the USA. Georgia Power is adding units 3 and 4 at its Plant Vogtle, which are Westinghouse AP1000 units with a net output of approximately 1,117 MW per unit. The company reports an estimated cost of US$6,300/kW. The current schedule for these units is for commercial operation to begin in 2019/2020. Two similar units are being installed by South Carolina Electric & Gas at the existing V. C. Summer nuclear station in South Carolina. These units are also scheduled to be on-line in the 2019/2020 timeframe. The fifth unit under construction, also a Westinghouse pressurized water reactor with a net capacity of 1,165 MW, is the Tennessee Valley Authority's Watts Bar unit 2. Construction of this unit was restarted in 2007 and the unit was connected to the grid in June 2016. News reports indicate that the unit has now operated at up to 40% of its capacity and is expected to be tested at full load during the remainder of 2016. The total project cost is now estimated at US$6.1 billion, i.e. US$5,236/kW. This unit is the first new nuclear generating unit to be commissioned in the US in twenty years. The available information indicates capital cost for these units in the CDN $ 6,000 – 7,500/kW range. However it is noted that these figures include costs incurred over an extended construction period and thus could be understated.

Cost Estimates for New Nuclear Generating Units

In its Annual Energy Outlook 2015 the US Energy Information Administration provides an overview of existing nuclear generating capacity and projections of uprates, retirements and new builds over the period to 2040. As of 2012, the total net operable generating capability in the USA was approximately 102,000 MW providing just under 20% of the country's total electricity supplies. The report's reference case projection for nuclear capacity up to year 2040 includes 9,000 MW of new additions, 200 MW of uprates and 3,200 MW of retirements. In its Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants dated April 2013, the EIA estimated an overnight capital cost of US$5,530/kW (2012$ and equivalent to CDN $6,500) for a dual unit nuclear plant with a total capacity of 2,234 MW, excluding financing costs and interest during construction. The EIA reports fixed O&M costs in the US$93/kW-yr (equivalent to CDN $135/kW-Yr, 2016$) range and variable O&M costs of more than US$2/MWh (equivalent to CDN $3.1/MWh, 2016$).

A new nuclear reactor built in New Brunswick could be one similar to the ACR-1000 technology. This facility would likely be a regionally shared facility because of the size. The capital cost was assumed to be in the order of CDN $7,500/kW for a new 1,100 MW unit. This is the upper end of the range for the US units and assumes that for a new nuclear unit to be given serious consideration as an option, the cost would need to be competitive with other nuclear options. Fixed and variable O&M costs are assumed to be in the range of $140 to $210 per kW-Yr and $3 to $6/MWh respectively.

Small Modular Reactors

The current generation small modular reactor (SMR) is designed to be built economically in factory-like conditions (rather than onsite), and with capacities between approximately 10 MW and 300 MW.

There is growing interest in SMRs to provide electricity to service small electricity grids, and possibly to provide heat for resource industries. SMRs can also be added incrementally to larger grids as demand grows. The IAEA estimates that as many as 96 SMRs could be operational worldwide by 2030.

Some SMR designs are in advanced stages of development, including several designed to be fully underground, minimizing land use, staffing, and security needs. Some designs include passive safety systems, and can operate for up to four years without refuelling.
SMR development can be generally grouped into two categories, utility-scale SMRs for main grid applications and small SMRs for off-grid and remote mine applications. The former group is discussed in this section.

Although SMR development has been supported by various governments (such as Canada, US, UK, Russia and China), regulatory agencies (such as the IAEA, Canadian Nuclear Safety Commission and United States Nuclear Regulatory Commission) and private companies (such as mPower, NuScale and Westinghouse), SMR technologies have not been fully commercially available. It is noted that there are a few operational SMRs around the world. Based on information published by the World Nuclear Association, there are at present three sizes of small reactors operating around the world, 300 MW units in Pakistan and China, 220 MW units in India and 11 MW units in Russia. The Association also lists three sizes of small reactors under construction, one 35 MW unit in Russia, one 27 MW in Argentina and two 105 MW units in China.

In Canada, Ontario-based Terrestrial Energy has announced plans to build a commercial Integral Molten Salt Reactor (IMSR) plant in Canada in the 2020's, which is being designed and engineered as a 400 MW unit and the IMSR technology can be formulated in the range from 80 MW to 600 MW.

It was reported in 2013 that Toshiba aimed to build a 4S (ultra super safe, small and simple) nuclear reactor in Alberta to supply energy to oil sand facilities, to be operational by 2020. However, no recent news has been located on this development.

News posted recently on the Nuclear Energy Institute web site indicates that the Tennessee Valley Authority (TVA) filed an "early site permit" application with the U.S. Nuclear Regulatory Commission in May 2016 for a potential SMR plant at its Clinch River Site in eastern Tennessee. This application is based on a plant parameter envelop encompassing the light-water SMRs currently under development in the United States by BWX Technologies, Holtec, NuScale and Westinghouse.

Capital Costs of Small Modular Reactors

As the SMR technologies have not been fully commercialized, there is very limited information on their costs publically available. A consortium prepared the Small Modular Reactor (SMR) Feasibility Study to the UK National Nuclear Laboratory in December 2014, which analyzed the overnight capital cost of four selected SMR designs. The study results show SMR cost varies from £4143/kW to £5754/kW. Without adjustment on inflation and application of an exchange rate of £1 to CDN 1.8, the capital cost range would be from $7,500/kW to $10,400 kW.

Due to their immaturity, it was estimated that the capital cost of SMRs would be in the proximity of $10,000/kW, with a range from $7,500/kW to $15,000/kW (-25% to +50%). Decommissioning cost is addition to the capital cost estimate.

In addition to the similar cost categories of conventional thermal power plants, operation of a SMR power plant will require funds to cover security, non-proliferation compliance, nuclear fuel waste management, spent fuel storage and licensing. It was estimated that the annual fixed operational cost of SMRs would be approximately 2% of the capital cost which based on a capital cost of $10,000/kW would be in the order of $200/kW-yr. As no specific information is available on variable operating costs, it is assumed that these would be $4.50/MWh as per the estimate for large nuclear plants.

One of the main SMR developers, NuScale released some cost information on November 3, 2015, which aims to use advanced manufacturing techniques, savings on facility costs and economies of scale to lower the levelized cost of electricity of its plants to US$ 90/MWh. The company has announced plans to deliver its first commercial plant in late 2023 to owner-operated Utah Associated Municipal Power Systems, which is composed of twelve 50 MW (12 x 50 MW) units.

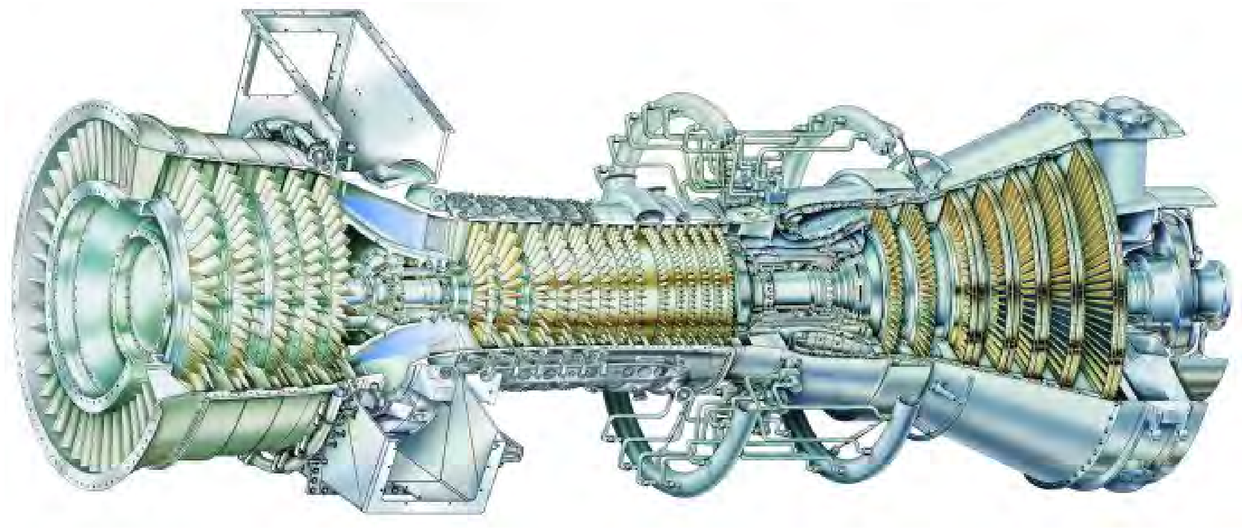
1.2 Natural Gas

How is electricity generated using natural gas?
A combustion turbine is a rotary engine that uses gas to generate electricity. An air/gas mix is ignited in a combustion chamber. The resulting gas flow is directed to the blades of a turbine which turn a shaft. The rotating shaft is connected to an electrical generator which converts the rotating shaft motion into electrical energy.

1.3 Combustion Turbines

Combustion turbines (CTs) are typically used for specialized needs and are available in unit sizes from as low as 10 MW up to 150 MW. They are tailored to system-peaking requirements or back-up supply to increase system security, and typically operate below 20 per cent capacity factor. The capital costs for these units are relatively small, but efficiencies are low in comparison to base load facilities so the fuel costs can be significant. This study has provided two options, similar in size of approximately 100 MW, but with two efficiency points.

Figure 2: Cross section of a GE LM6000 combustion turbine



A high efficiency option was included in this study using a nominal 100 MW natural gas-fired simple cycle combustion turbine based on two GE LM6000PH combustion turbine generators with dry low NO_x combustors. The mid-efficiency option, assuming a nominal 90 MW natural gas-fired simple cycle combustion turbine, was based on one GE 7E.03 combustion turbine generator with dry low NO_x combustors. The mid-efficiency combustion turbine plant option is a newer technology than the combustion turbines located at NB Power's Ste. Rose and Millbank Generating Stations, which employ the older model GT11N1 and operate on diesel fuel.

Post-combustion emissions controls (i.e., SCR – selective catalytic reduction) for both CT options were assumed not to be required as a CT generator is capable of achieving NO_x emissions of fifteen parts per million (ppm) or less.

Pipeline gas was assumed to be available at adequate pressure to support combustion turbine operation at all ambient conditions without on-site gas booster compressors.

The project capital costs were estimated based on a factored cost methodology, using Hatch in-house data and recent vendor quotes for the major equipment.

The operational costs for this alternative include costs for operators of the facility, maintenance labour and materials and the administrative costs to provide the facility service. Non-fuel operating and maintenance costs were estimated based on a peaking duty mode of operation with approximately 500 hours of operation and 150 starts per year. Staffing was assumed to include four operators, two maintenance personnel and an allowance for administration/management staff.

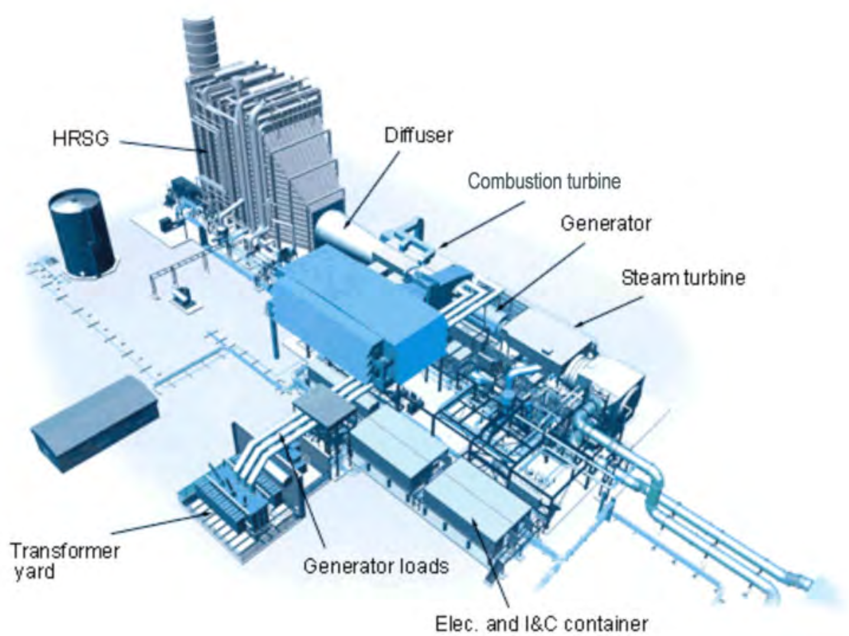
Project lead time, from notice to proceed to commercial operation date, would be two years, based on combustion turbine delivery time of 15 months after receipt of order. This combustion turbine plant would have an accounting life estimated at 25 years.

1.4 Combined Cycle

In a combined cycle power plant, a combustion turbine (normally operating on natural gas) generates electricity. The waste heat from the exhaust is used to make steam to generate additional electricity via a steam turbine. This last step enhances the efficiency of electricity generation. Typical thermal efficiencies of combined cycle power plants range between 50 to 60 per cent, depending on the equipment used and the configuration. Typically, about one-third of the electricity is generated from the combustion turbine and two-thirds from the steam turbine generator.

A combined cycle system includes single-shaft and multi-shaft configurations. The single-shaft system consists of one combustion turbine, one steam turbine generator and one Heat Recovery Steam Generator (HRSG). This configuration is typically called a 1x1x1 arrangement and is shown in Figure 3. The combustion turbine generator set and steam turbine generator set are coupled in a tandem arrangement on a single shaft. The key advantage of this single-shaft arrangement is its operating simplicity with higher reliability than multi-shaft configurations. Further operational flexibility is provided with a steam turbine that can be decoupled for simple cycle operation of the combustion turbine as stand-alone operation.

Figure 3: Typical combined cycle system configuration



In some cases the construction of these systems can be phased so that the combustion turbines are built first and operated, with the steam system added later.

This study included three sizes of combined cycle plants; a large size in the order of 420 MW, a medium size of about 285 MW and a small size of about 120 MW, each with varying efficiencies.

The large combine cycle generation option is for a nominal 420 MW natural gas-fired combined cycle power plant. The reference plant would be a 1x1x1 arrangement based on a Mitsubishi M501GAC (air-cooled) combustion turbine generator with dry low NO_x combustors, triple pressure reheat HRSG with SCR and a nominal 140 MW steam turbine generator. Thermal efficiency is approximately 52 per cent.

The medium combined cycle option is for a nominal 285 MW natural gas-fired combined cycle power plant. The reference plant would be a 1x1x1 arrangement based on a General Electric 7F.04 combustion turbine generator with dry low NO_x combustors, triple pressure reheat HRSG with SCR and a nominal 100 MW steam turbine generator. Thermal efficiency of this option is approximately 50 per cent.

The small combined cycle option is for a nominal 120 MW natural gas-fired combined cycle power plant. The reference plant would be based on a 2x2x1 arrangement that includes two GE LM6000PH combustion turbine generators with low NO_x combustors, two heat recovery steam generators, and one steam turbine generator. Thermal efficiency of this option is approximately 47 per cent. Two options of this smaller version of combined cycle were included: one with once-through cooling water access and one that included a cooling tower for plant cooling. The latter would be required if access to seawater was not readily available.

The plant location assumed for all options, unless otherwise specified, would be located adjacent to an existing power generation facility on the coast and would employ a once-through seawater cooling system. Site average performance was estimated based on an elevation of 8 m AMSL and annual average temperature of 5.5ºC, and an annual seawater inlet temperature of 7.5ºC.

Post-combustion emissions controls (SCR) for the medium and small combined cycle options were not included to reduce NO_x emissions as the combustion turbines are capable of achieving NOx of 15 ppm. An oxidation catalyst for carbon monoxide (CO) abatement were not included as all the combustion turbine CO emissions are low and the pollutant is not specifically addressed in Environment Canada's *National Emission Guidelines for Stationary Combustion Turbines.*[20]

[20] https://www.ccme.ca/files/Resources/air/emissions/pn_1072_e.pdf

It was assumed that pipeline gas would be available at adequate pressure to support combustion turbine operation at base load without on-site gas booster compressors.

The overnight total project costs were estimated based on a factored cost methodology using Hatch in-house data and recent vendor quotes for the major equipment. Costs include three generator step-up transformers. Also, it was assumed that a piped municipal water supply and a sanitary sewer up to the plant fence would be available, as well as natural gas lateral piped to a metered regulating station located adjacent to the plant fence.

The operational costs for this option include costs for operators of the facility, maintenance labour and materials, and the administrative costs to provide the facility service. Non-fuel operating and maintenance costs were estimated based on an intermediate duty cycling mode of operation with approximately 7,000 hours of operation and 75 starts per year. Fixed costs include operations and maintenance staff, administrative costs and fixed maintenance, and long-term service agreement costs. Variable O&M costs include major planned maintenance parts and labour, unscheduled maintenance, SCR catalyst replacement and disposal, chemicals and consumables and municipal water.

Project lead time would be approximately 36 months. All combined cycle plant options would have an accounting life of 25 years.

1.5 Hydro

How is electricity generated using hydro resources?
Hydroelectric power is generated from the movement of water from a reservoir through a channel or pipe into a turbine. The flowing water makes contact with turbine blades, causing the shaft to rotate. The rotating shaft is connected to an electrical generator that converts the rotating shaft motion into electrical energy. A hydroelectric facility requires a dependable flow of water and a reasonable height of fall of water commonly called the head. According to the CEA, 63.3 per cent of the electricity generated in Canada came from hydro in 2012.

1.5.1 Grand Falls Additional Power

The existing Grand Falls Generating Station is located on the St. John River. The station is situated on an oxbow-like turn in the river in the town of Grand Falls. The initial water drop in the river is at the falls, and then cascades to the powerhouse location where the river widens to a gentle flow. The total drop in elevation is approximately 39 m.

The existing station, shown in Figure 4, was built in the mid-1920s. It is comprised of a concrete gated control structure near the crest of the falls, a riverbank intake structure, a concrete-lined tunnel in bedrock (inside diameter of 7.5 m), a surge tank, a short, steel penstock and a four-unit powerhouse at the base of the gorge. The powerhouse is comprised of four units with an initial installed capacity of 60 MW. As a result of unit upgrades in the mid-1990s, the powerhouse capacity is now 66 MW.

Figure 4: The Grand Falls Generating Station

The addition of a new hydroelectric facility adjacent to the existing 66 MW station at Grand Falls is technically feasible and could be readily constructed. Additional power at this site would add to NB Power's portfolio of renewable energy generation, further demonstrating a commitment to environmental leadership.

The project would have many advantages, including:

- low project cost per kW;
- use of existing water storage structures;
- low environmental effect;
- improved use of water resources by utilizing more of the available water and decreasing spill at the site;

- all land for the proposed project is already owned by NB Power; and
- the ability to carry out the entire construction without shutting down hydroelectric production at the existing generating station.

The new construction and main equipment that would be required for the new facility includes:

- a power intake structure – concrete structure with trash racks, steel vertical gate and stop logs;
- a drop shaft immediately downstream of intake, to an approximate 700 m long power tunnel, running parallel with the existing tunnel;
- a surge tank;
- a powerhouse located just west of the existing four-unit powerhouse; and
- one or two vertical Francis turbines.

The anticipated additional annual generation would be approximately 300 GWh (with 100 MW installed capacity).

Figure 5: Artist's rendition of the additional power project for Grand Falls

Project lead time would be approximately 48 months. This hydro plant would have an accounting life of 100 years (provided that upgrades occur after 50 years).

1.5.2 High Narrows

The proposed High Narrows project is located in northern New Brunswick, south of the city of Bathurst. The project site is approximately 12 km upstream of NB Power’s existing Nepisiguit Falls Generating Station (previously known as Great Falls).

Figure 6: NB Power’s existing Nepisiguit Falls Generating Station

A pre-feasibility study was completed in 1980 by Rosseau, Sauvé, Warren Inc. (RSW) that evaluated the feasibility of harnessing hydroelectric potential at various sites along the Nepisiguit River. As a result of that work, the High Narrows project was determined to be a viable option for a potential hydroelectric development.

The addition of a new hydro station on this river would add to NB Power’s portfolio of renewable energy generation.

The project would have many advantages, including:

- attractive project cost per kW;
- complementing the energy production at the existing Nepisiguit Falls Generating Station; and
- dam construction fill materials are available in abundance near the proposed dam site.

Main structures and equipment required for the proposed hydroelectric facility include:

- a diversion tunnel;
- a zoned earthfill dam;

- a concrete gated spillway;
- an intake structure;
- penstocks;
- a surface powerhouse; and
- three vertical Francis turbines.

Detailed hydro-technical analysis, including power and energy computer simulations of both the proposed new station at High Narrows and the existing Nepisiguit Falls Generating Station, yield the following options and incremental energy estimates:

- 20 MW and 71 GWh per year;
- 30 MW and 108 GWh per year;
- 40 MW and 148 GWh per year; and
- 60 MW and 180 GWh per year.

The 40 MW option was selected for evaluation in this IRP. A project schedule was prepared and consists of all stages of project development, including the environmental process, engineering, tendering, turbine/generator supply and construction.

For the 40 MW option, the project lead time would be approximately 60 months. This new hydro plant would have an accounting life of 100 years (provided that upgrades occur after 50 years).

1.6 Interconnection Purchases

The New Brunswick transmission system has been strategically designed to provide reliable energy to in-province customers while also providing a means with neighbouring utilities to buy and sell electricity through interconnections. These interconnections allow NB Power to purchase electricity at various times when the cost to supply electricity from in-province sources becomes more costly than market prices. But the interconnections also allow NB Power to consider options to purchase electricity from another region on a long-term contractual basis (25 years) that then can be used to defer the need to build new generation that will be required in the long-term to meet in-province requirements. There are several regions where NB Power can purchase electricity; two regions of particular interest, because of the potential availability of electricity from renewable hydro resources, are Quebec and Newfoundland and Labrador.

There remains uncertainty with respect to final terms and conditions for these contractual purchases and the assumptions with respect to pricing alternatives. For this study it was assumed that firm capacity would be priced at equivalent to the installed capital costs of new combustion turbines with energy priced at market prices.

1.6.1 Lower Churchill

The Churchill River in Labrador is a significant source of renewable electrical energy. However, the potential of this river has yet to be fully developed. The existing 5,428 MW Churchill Falls Generating Station began producing power in 1971, and harnesses about 65 per cent of the potential generating capacity of the river. The remaining 35 per cent is located at two sites on the lower Churchill River, known as the Lower Churchill Project.

Figure 7: Location of the Lower Churchill Project

The Lower Churchill Project consists of two of the best undeveloped hydroelectric sites in North America:

- Gull Island, which is located 225 km downstream from the existing Churchill Falls Generating Station. The 2,250 MW project at Gull Island has the potential to produce an average of 12 terawatt hours (TWh) of energy per year; and
- Muskrat Falls, which is located 60 km downstream from Gull Island. The 824 MW project at Muskrat Falls has the potential to produce an average of 5 TWh per year. This project is currently under construction.

Figure 8: Artist's rendition of the Gull Island project

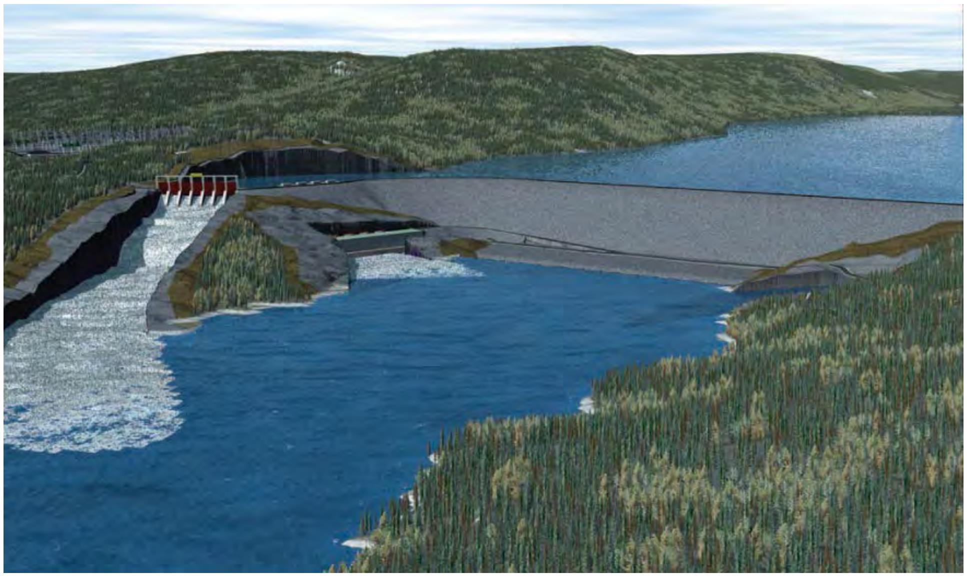
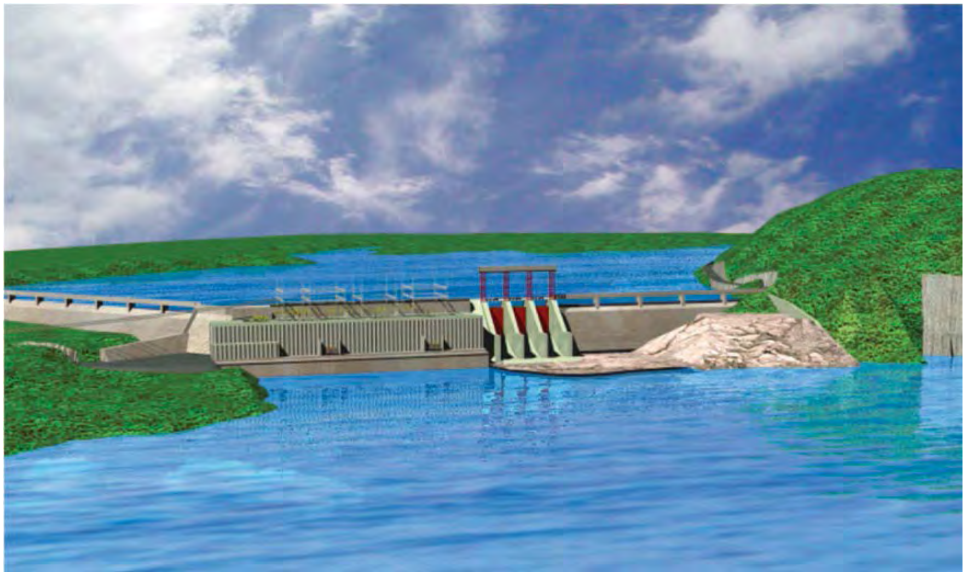


Figure 9: Artist's rendition of the Muskrat Falls project



This much needed resource of clean and stable renewable energy provides the opportunity for Newfoundland and Labrador to meet its own domestic and industrial needs in an environmentally sustainable way, with enough power remaining to export to other jurisdictions where the demand for clean energy continues to grow.

Nalcor, the Crown-owned parent company of Newfoundland and Labrador Hydro, is now developing the Muskrat Falls project and will transmit hydropower via a 1,200 km HVDC link from Labrador to Newfoundland's Avalon Peninsula near St. John's. Another HVDC link will connect the power system of the island of Newfoundland to the Nova Scotia power system. The majority of the energy from Muskrat Falls will serve both Newfoundland load as well as provide contractual capacity and energy to Nova Scotia.

The Gull Island project has some potential to provide NB Power with capacity and renewable energy in the future. Once completed, this electricity source could reduce New Brunswick's dependency on imported hydrocarbon fuels and, over the longer term, provide replacement capacity for the capital stock turnover of NB Power's existing fossil fuel resources for 40 years or more.

1.6.2 Other Interconnection Purchases – HQ Expansion Projects

Hydro-Québec (HQ) continues to develop Quebec's hydroelectric power potential. The Eastmain-1-A/Sarcelle/Rupert Project was completed in 2013. This project increased capacity by 918 MW and 8.7 TWh of energy. The Romaine Project, which started in May 2009, will add 1,550 MW of capacity and 8 TWh once completed in 2020. The installed capacity of HQ's hydroelectric generating fleet is nearly 1,000 MW greater than in 2008.

2 ALTERNATIVE SUPPLY OPTIONS

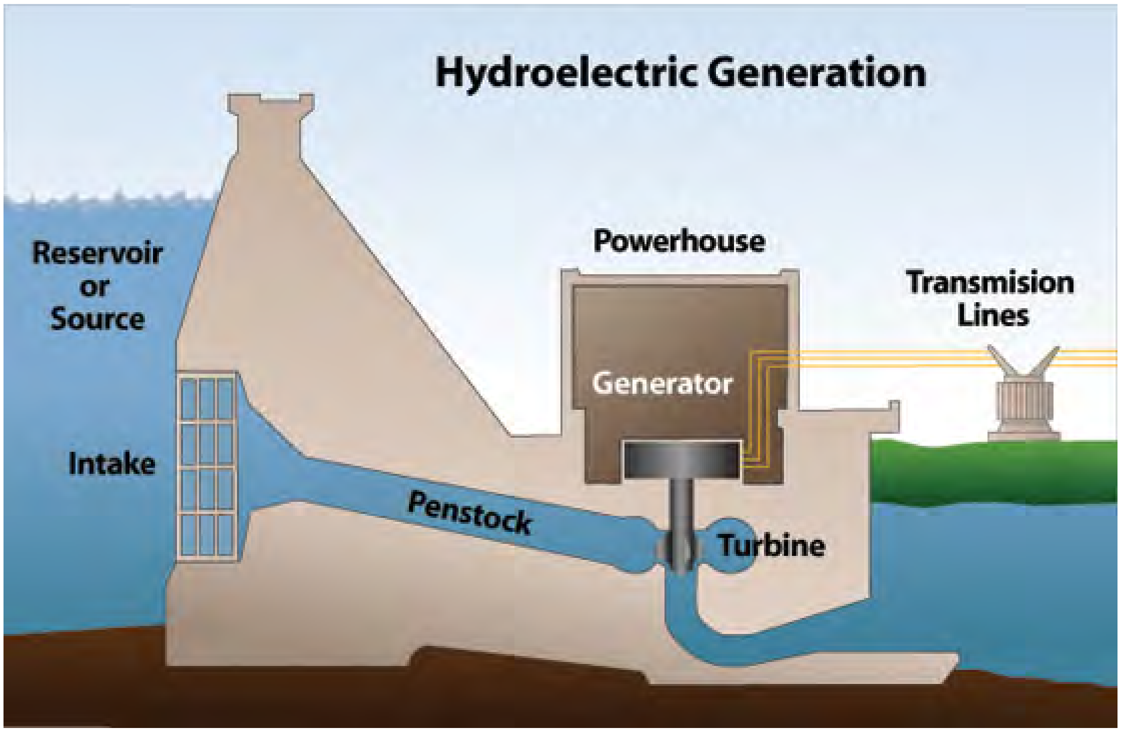
2.1 Small Hydro

How is electricity generated using small hydro?
Although there is no consensus by industry on the definition of "small" hydro, the upper limit is generally around 10 to 20 MW. See Section 1.5 (Hydro) for details on how hydroelectricity is generated. Many rivers exist in New Brunswick that could offer favourable conditions for low-impact run-of-river hydro developments. The advantage of this type of system is that it normally has a minimal impact on the ecosystems, and on fish habitat and passage.

This IRP evaluation has considered the small hydro plant size of 20 MW, slightly higher than the Canadian definition,[21] but within the generally recognized range.

[21] International Association for Small Hydro (IASH), 2009

Figure 10: Typical small hydro configuration



Several candidate sites for small hydro development within New Brunswick were identified in a 1984 study by Monenco.[22] This study, as well as a recent survey[23] of undeveloped hydropower potential in province, suggests that opportunities exist for further hydropower development with several candidate sites that can deliver or exceed the power production assumed in this cost review.

Head is of vital importance in a hydro plant cost estimate (the lower the head, the larger the water passages in the water transport and hydraulic equipment). In New Brunswick, existing sites are all considered to be low- to medium-head sites where head does not exceed 40 metres.

The undeveloped (green field) site capital cost estimates were based on Hatch experience and various industry publications and references. In general, the capital costs estimates provided by the various industry publications and references were typically based on historical experience and plant data, and are meant for high-level estimation purposes only. It is important to note that specific site details may have a significant impact on total project cost and feasibility.

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[22] "Identification of Environmentally Compatible Small Scale Hydroelectric Potential in Atlantic Canada", Monenco Limited, January 1984.

[23] http://www.eem.ca/index.php/case-studies/survey-of-canadian-hydropower-potential

These details can include:

- Topography;
- type of site/scheme (run-of-river, natural reservoir or man-made reservoir);
- access to the undeveloped site;
- available head and flow;
- civil structural requirements;
- spill capacity requirements; and
- distance to transmission systems.

Site-specific details and requirements must be carefully considered and fully explored in order to properly assess impact on project economics.

Operating and Maintenance (O&M) cost estimates for a 20 MW small hydro site were developed based on average industry costs for a wide variety of plant sizes and locations using various benchmarking methods. Because annual O&M costs for any given unit or plant can vary significantly depending on many factors, benchmarking methods were used that were based on published statistical data gathered from hydro facilities across North America.

Based on Hatch experience and industry statistics, development time frames from the concept to online date for hydroelectric facilities can range significantly depending on the complexity of the project.

According to the Canadian Hydro Association in 2006, on average, a hydropower project requires 8 to 12 years of preparation, from the preliminary step to its commissioning. Similarly, in 2006 and based on a range of reports, the Ontario Power Authority forecasted construction lead times for projects 10 MW or less to be approximately four to seven years.

The expected service life for new hydroelectric facilities is typically 50 years, with civil structures exceeding 100 years. Many facilities in North America have surpassed 100 years of service as a result of receiving life extensions every 20 to 40 years.

While the overall service life on many components is typically 50 years, it is noteworthy that certain components typically wear out before the end of the service life and need to be replaced or refurbished.

The following is a list of these components and each corresponding typical expected life.

Figure 11: Expected life of hydro components

Component	Typical expected life
Water conveying and control structures (channels and tunnels, gates and associated cranes, penstocks, surge alleviation facilities, intake valves)	50 years
Turbine	50 years
Governor system	50 years
Generator (rotor, stator, bearings, excitation systems)	35 years
Generator power transformer	35 years

2.2 Wind

How is electricity generated using wind?
Wind power is generated from the movement of wind passing the blades of a wind turbine. The rotating shaft of the turbine is connected to an electrical generator which converts the rotating shaft motion into electrical energy. Wind projects continue to develop at a rapid speed globally. According to the CEA, wind accounted for 1.5 per cent of the electricity generated in Canada in 2012.

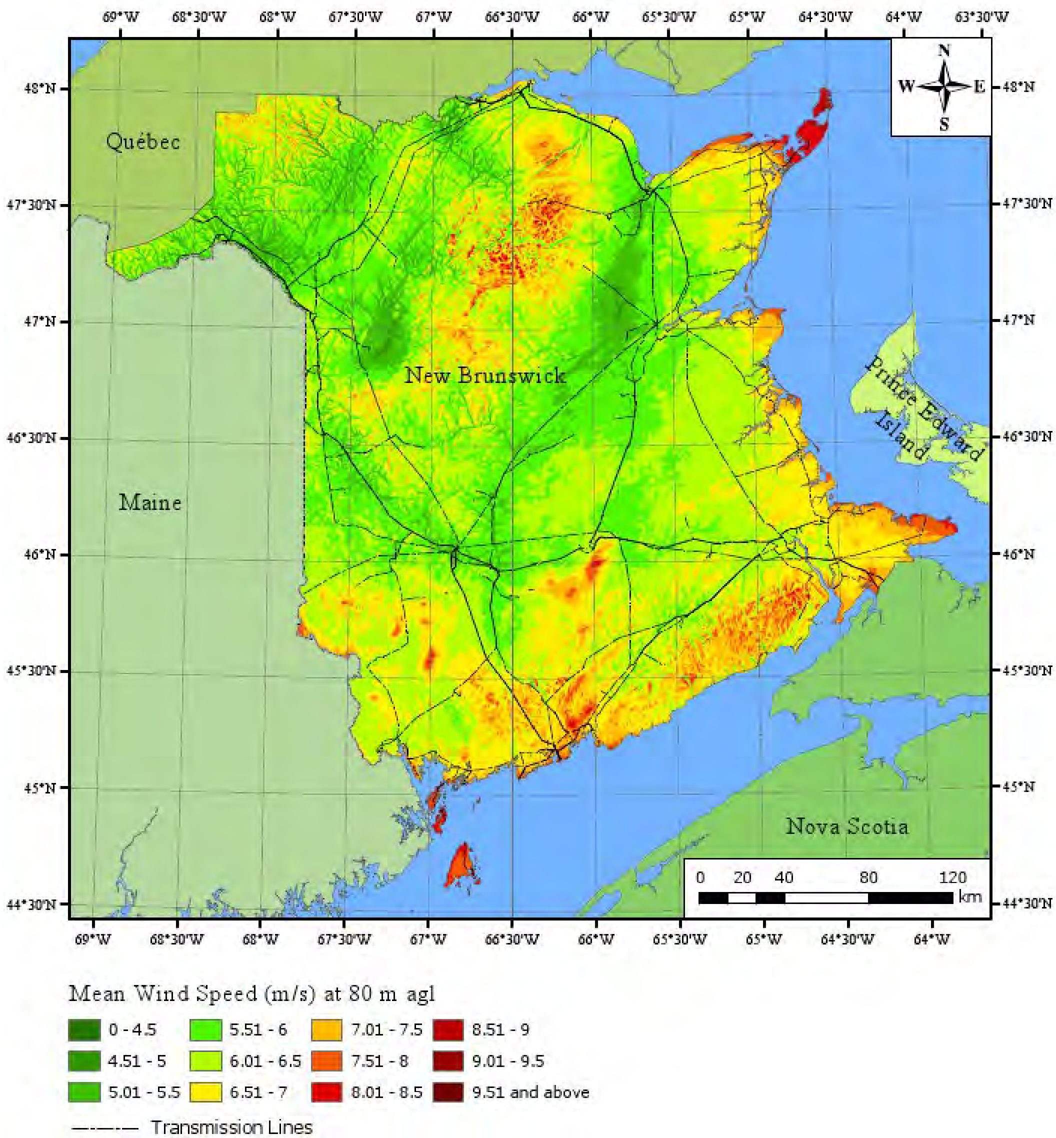
New Brunswick currently has a total of 294MW of installed nameplate wind capacity; 150 MW at the Kent Hills Wind Farm (see Figure 12) and 99 MW at the Caribou Mountain Wind Park with an additional 45 MW located in Lameque. According to the Canadian Wind Energy Association (CanWEA), and as of December 2016, Canada has about 11,898 MW of wind capacity installed. Much of this wind generation is located in Ontario, Quebec and Alberta.

Figure 12: TransAlta's Kent Hills Wind Farm, New Brunswick's first wind development

The majority of New Brunswick has average wind speeds of 6 to 7 m/s, with pockets over 7.5 m/s (at 80 m) (see Figure 13). These wind velocities are favourable to additional commercial-scale wind power development and are comparable to other areas in Canada with significant utility-scale activity (for example, the west coast of Lake Huron in Ontario). A report by Ea Energy Analyses of Denmark indicates that there is strong potential for wind development of up to 7,500 MW in New Brunswick by 2025.[24]

[24]http://www.ea-energianalyse.dk/reports/725_large_scale_wind_power_new_brunswick.pdf

Figure 13: Mean wind speeds in New Brunswick



Costs for two wind farms were considered in this study, a small-scale farm of 10 MW and a larger wind farm of 50 MW. Wind turbine unit size has some influence on capital cost; generally, but not universally, the larger the unit size, the lower per kW cost. For this IRP, plants based on 2.0-3.0 MW units were assumed.

There are four primary elements to wind project costs as shown in Figure 14.

Figure 14: Elements of costs for wind projects

Element	Portion of costs (per cent)	Includes
Generating equipment	65-75	the wind turbine blades, nacelle and tower, as well as commissioning costs
Mechanical/civil balance of plant	12-14	the construction of turbine foundations, crane pads, access roads and the erection of turbines
Electrical balance of plant	8-10	collection system, substation, switchgear and transmission interconnection
Project development (owner and consultants)	4-8	regulatory requirements, permitting, Environmental Impact Assessment, project management

The capital cost estimates provided in Appendix 3 were based on Hatch experience with wind developments in Canada up to 200 MW in size, as well as on a GL Garrad Hassan assessment of capital and operational expenditures for wind farms prepared for the Canadian Wind Energy Association [GLGH 2012][25].

The economics of a wind development project are heavily influenced by site-specific factors such as wind resource (which affects the machine class and hub height) and topography (the primary factor in transportation, civil and electrical costs). The main capital replacements over the project's lifecycle are turbine blades, gearboxes, and pitch and yaw systems. The necessities of these replacements are dependent on site conditions and vary by turbine manufacturer (some manufacturers produce direct-drive generators with no need for a gearbox).

Wind power is a relatively mature business with costs dominated by the turbine supply. The turbine supply cost is impacted by a number of site-specific factors including machine class, swept area (power output), hub height, transportation and erection. Non-site factors include technology selection (gearless versus geared, for example). Turbine costs in Hatch's database have varied by as much as $600 per kW and by $400 per kW in the GLGH report. The costs at the high end of the range would likely stem from the installation in isolated arctic projects where logistics, construction equipment and materials are extremely expensive to bring on site. However, breaking down the range of turbine costs into site and non-site specific factors was not attempted in this study. The other site-specific cost factor is the balance of plant category (civil/electrical), which varies by terrain and turbine density.

[25] http://www.canwea.ca/pdf/Assessment_Est-Cost-of-Wind-Energy_BC.pdf

One study of O&M costs for wind turbines produced a cost range of 1.5 to 2 per cent of original turbine investment [DWEA, 2009], or approximately $32 per kW per year (at 1.75 per cent). Add to this the costs associated with balance of plant (mainly the substation) and the total O&M cost increases beyond the operating expenditures (OPEX) for generating equipment alone. However, with increasing North American data about actual OPEX and many machines coming out of warranty, more evidence is presenting itself that suggests the O&M costs are closer to $70 per kW per year. This large increase is due to costs that were previously masked by the warranty and a small experience database in North America. The GLGH report suggests that for a small-scale wind farm, O&M is $86 per kW per year, while for large-scale wind farm, the value is $62 per kW per year.

The project lead times would be approximately three to four years, depending on the size of the project. Before a turbine purchase order is made, the environmental assessment study, permitting, interconnection studies, resource assessment and land lease agreements typically take two to three years. The larger project developers have volume purchase agreements with the major equipment suppliers, which can result in significantly reduced project turnaround time after the permitting phase.

Equipment lead times, depending on the size of the project, would be approximately one year, during which time mechanical, civil and electrical balance of plant is usually completed. Turbines can be erected quickly after the foundations are poured and cured, typically in parallel, taking two to three weeks each, including commissioning. A wind development typically has an accounting life of 20 years.

2.3 Ocean Power

How is electricity generated using ocean power?
Ocean power is a form of hydropower that converts the energy of tides or waves, into electricity or other useful forms of power.

Tidal stream turbines draw energy from water currents in a way similar to how wind turbines draw energy from wind. The higher density of water (which is 800 times the density of air) means that a single generator can provide significant power at low tidal flow velocities (compared with wind speed).

Wave power captures the movement of waves using devices such as buoy-like structures that convert wave motion to mechanical energy, which is then converted into electricity and transmitted to shore over a submerged transmission line.

2.3.1 Tidal Stream

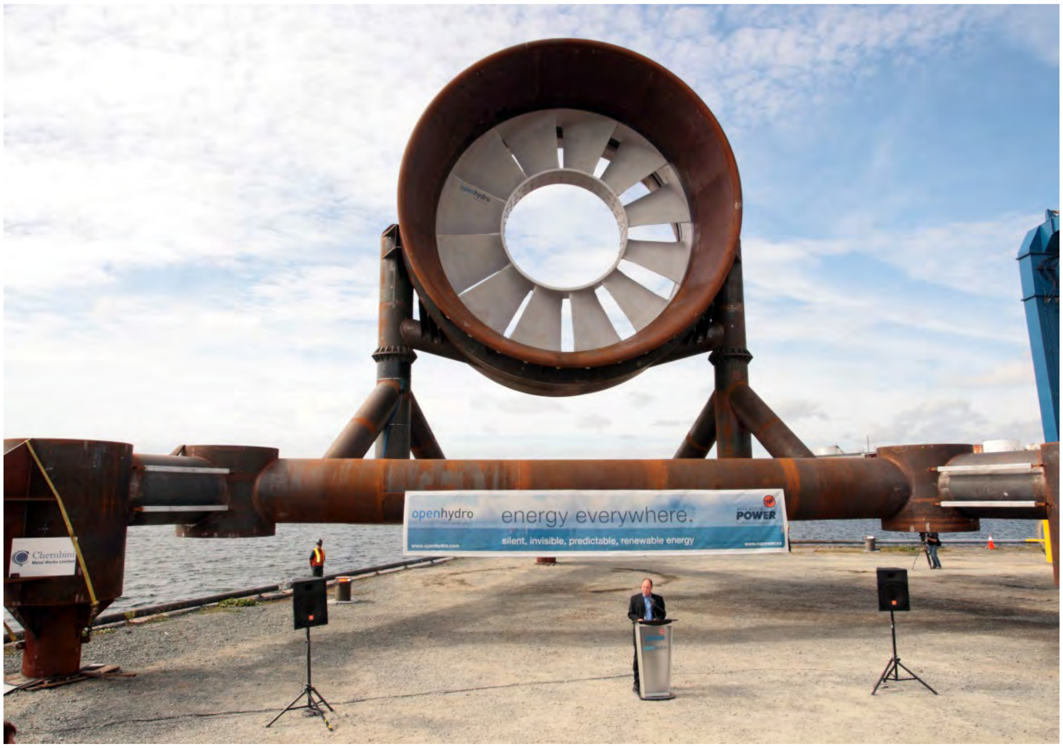
Tidal currents are water flow motions caused by the rise and fall of tides, salinity, thermal and underwater topography. The kinetic energy of the currents can be transformed into electricity by the use of horizontal or vertical axis hydrokinetic turbines. This method is gaining in popularity because of the lower cost, and of lower ecological impact when compared to tidal barrages.

A 50 MW tidal stream development in the Bay of Fundy area on a single site was considered for this IRP.

Some of the hydrokinetic technologies being developed and studied today are shown below.

In November 2009, Emera Inc. and its tidal technology partner, OpenHydro, successfully deployed its first commercial-scale, in-stream tidal turbine in the Bay of Fundy. The 1 MW turbine is shown in Figure 15.

Figure 15: In-stream tidal turbine used in Nova Scotia



In 2016, Emera deployed the first of two second generation in-stream tidal turbine in the Bay of Fundy. This 2 MW turbine is shown in Figure 16

Figure 16: Second Generation In-stream tidal turbine used in Nova Scotia

This turbine is part of a demonstration facility being hosted by the Fundy Ocean Research Center for Energy (FORCE) located in the Minus Basin region of the Bay of Fundy. FORCE acts as a host to turbine developers, providing a shared observation facility, submarine cables and grid connection at its pre-approved test site. The test site features water depths of up to 45 meters at low tide, a bedrock sea floor and relatively straight-flowing currents, with peak speeds exceeding 5 m/s. FORCE also oversees independently reviewed environmental monitoring in the Minas Passage. FORCE also conducts research to better understand the site conditions, estimated to contain 2,500 megawatts of extractable power.

There are four different tidal in-stream developers holding berths at FORCE:

- Minus Energy (with Marine Current Turbines and Bluewater Energy Services)
- Atlantis Resources Corporation (in partnership with Lockheed Martin and Irving Shipbuilding)
- Cape Sharp Tidal (a joint venture between Emera Inc. and OpenHydro)
- Black Rock Tidal Power (with Schottel as principal turbine developer)

There are at least three commercial-scale tidal power projects operating in the world (including a 20 MW plant in Nova Scotia), and these are all barrage plants. However, the kinetic energy of the marine currents can also be transformed into electricity by the use of horizontal or vertical axis hydrokinetic turbines.

Several turbine types are currently being tested. They include:

Axial Turbines – bottom mounted (anchored) or semi-submerged floating cable tethered.

Similar in concept to windmills operating under the sea. This type of turbine has the most prototypes currently operating, as well as a few commercial-scale applications. Their rated power typically ranges from 300 kW to 1.2 MW per turbine. This design is most used in the UK and the United States.

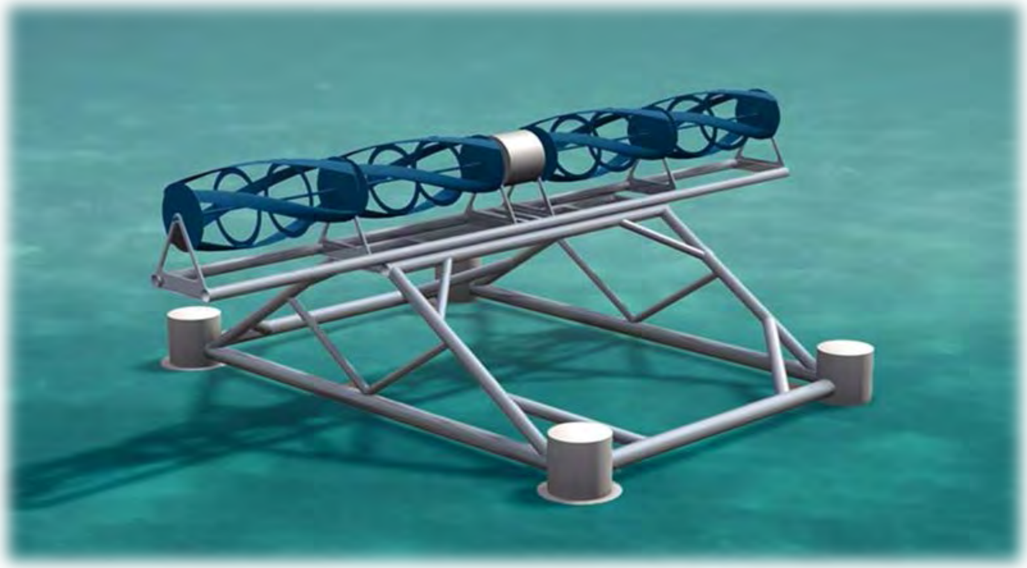
Figure 17: Typical bottom mounted axial tidal stream turbine

[Norwegian Environment Technology Center]

Axis Crossflow Turbines

This design is similar to standard hydropower crossflow turbines, but installed on the seabed. These turbines can be deployed either vertically or horizontally. They feature a helical blade design. Some projects using crossflow tidal turbines are being commercially piloted on a large scale in South Korea.

Figure 18: Typical crossflow tidal stream turbine

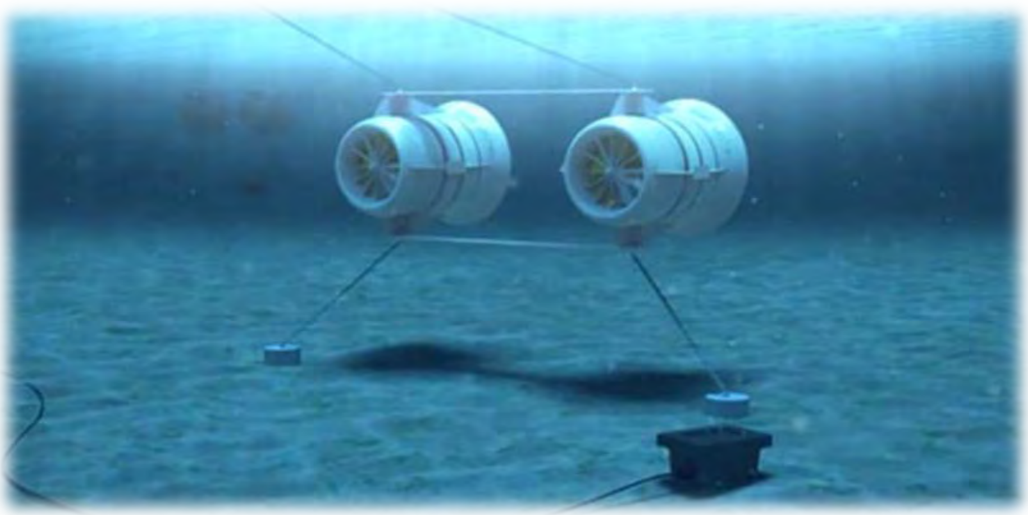


[Subsea World News]

Flow Augmented Turbines

This type uses flow augmentation measures, such as ducts or shrouds, which increase the incident power available to a turbine relative to the two previous types (axial and crossflow). Australian companies have performed successful commercial trials for this type of turbine.

Figure 19: Typical flow augmented semi-submerged floating tethered stream turbine

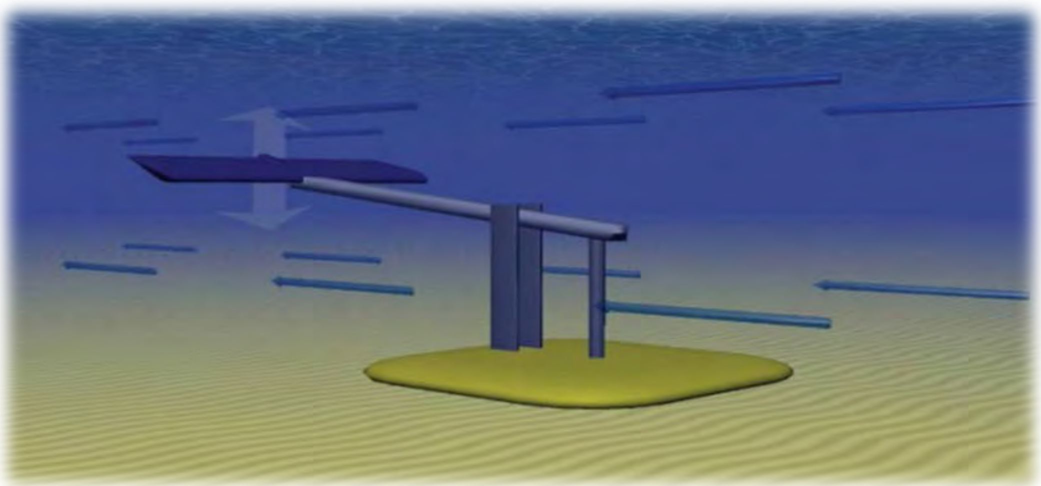


[hight3ch.com]

Oscillating Devices

These apparatuses do not have rotating components; rather, they make use of aerofoil sections that are pushed sideways by the flow. The motion is then used to power a hydraulic motor, which then turns a generator. European companies should shortly commission commercial-scale applications for this type of turbine.

Figure 20: Example of tidal oscillating device



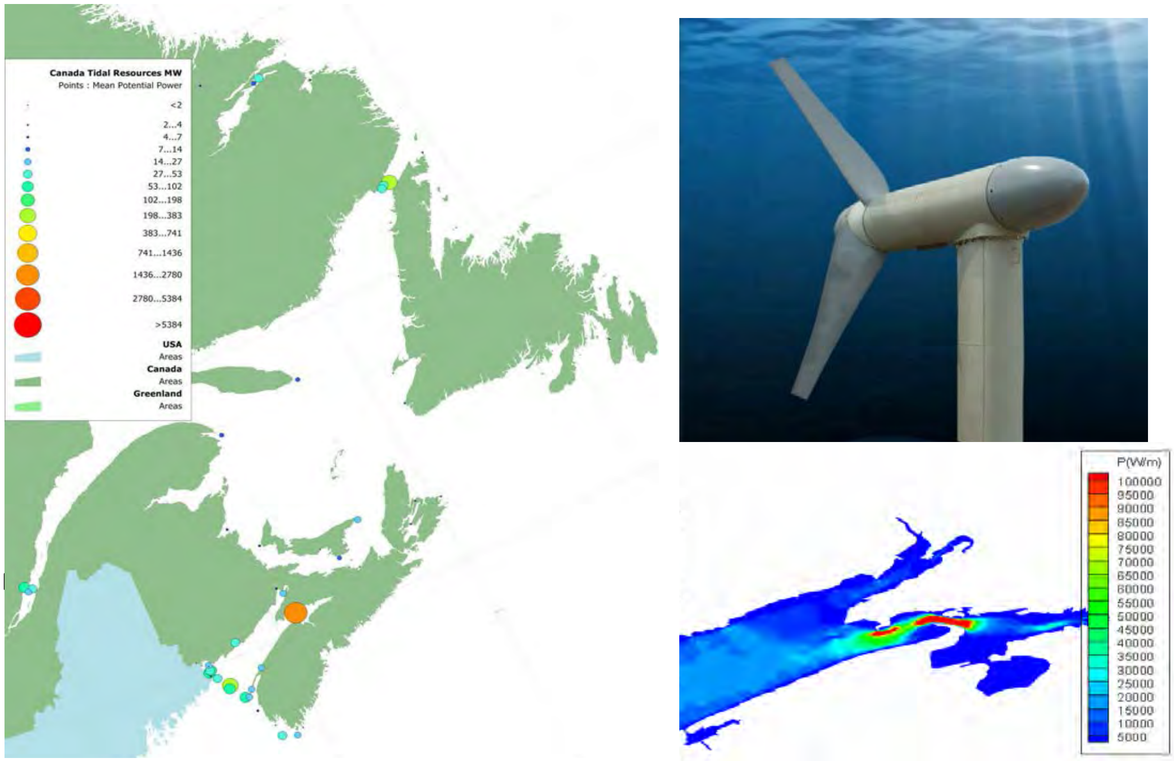
[Engineering and Technology Magazine]

Tidal stream generators are new technologies and are not commercially mature. As such, none of the above-mentioned turbine types have either become standard or emerged as the clear leader. Very few applications have been implemented on a commercial scale. Several prototypes have shown promise, with many companies making bold claims, some of which are yet to be independently verified. However, they have not operated commercially for extended periods to establish performance benchmarks and reliable information on rates of return on investment. Nonetheless, this method is gaining in popularity because of the lower cost and lower ecological impact when compared to tidal barrages.

Nova Scotia has started the procurement process for commercial-scale tidal stream schemes to be implemented in the Minus Basin region of the Bay of Fundy. This activity could provide information on the costs and performance of tidal stream power that could be of interest to New Brunswick.

For this study, a 50 MW tidal stream development in the Bay of Fundy area on a single site is considered.

Figure 21: Left: Potential Tidal Current Resource Sites; Top Right: Typical Horizontal-Axis Kinetic Turbine; Bottom Right: Tidal Power Density in the Bay of Fundy (W/m)



Although turbine performances are important, what really distinguishes one application and technology from the others is the support/anchoring system. This component has a significant impact on capital expenditures (CAPEX) and operating expenditures (OPEX).

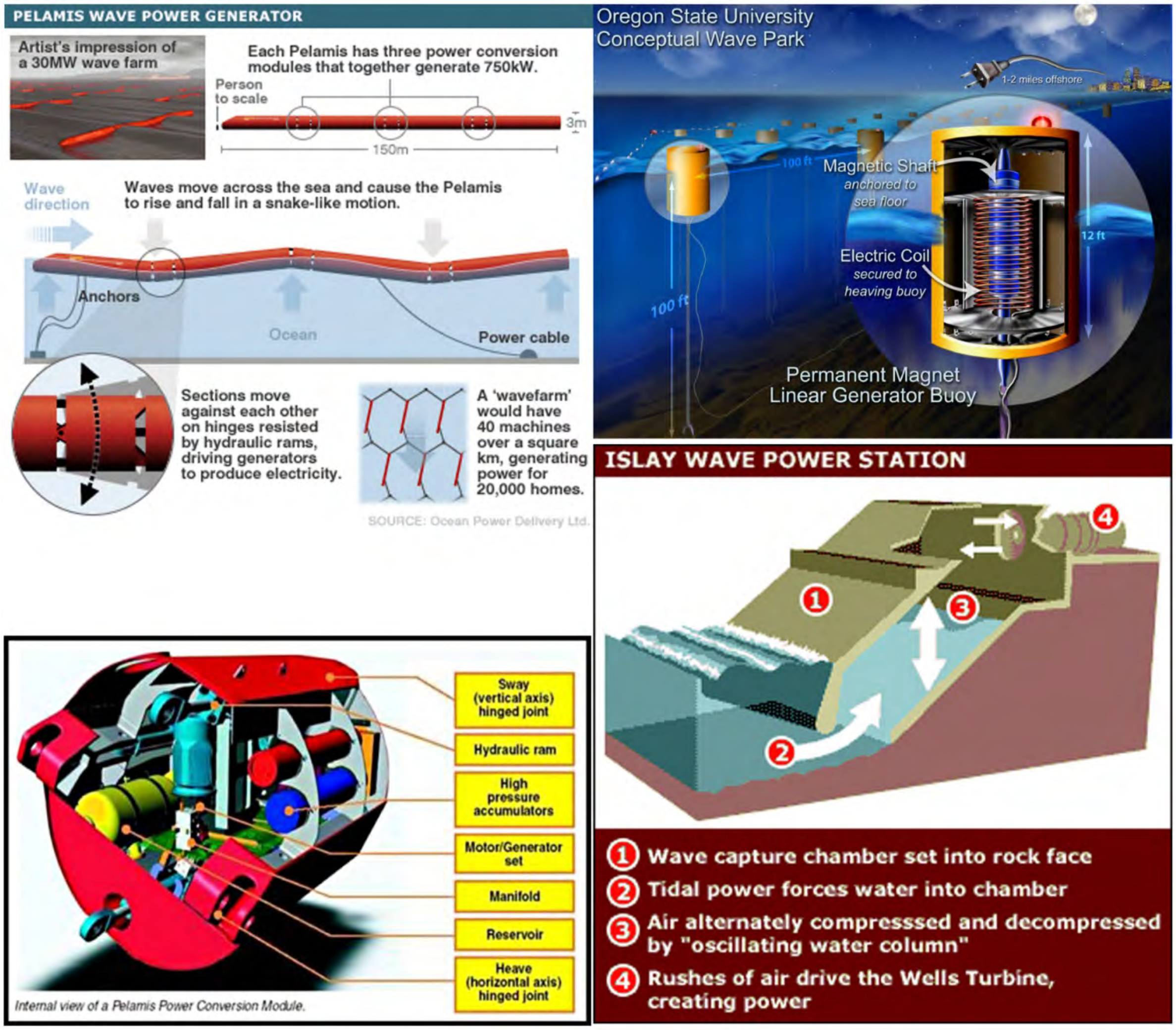
2.3.2 Wave

Devices that extract energy from ocean waves generally fall into two classes:

- near-shore devices that are rigidly mounted to the sea bottom or a rocky shore; and
- offshore devices that incorporate one or more semi-buoyant or floating oscillating bodies.

It has been suggested that the best wave power resource is offshore, due to the increased kinetic energy potential in waves offshore.

Figure 22: Typical wave power resource options



This study estimated the cost for a 10 MW wave power plant based on a surface-following system (shown in the leftmost part of Figure 22) that is an offshore device. The project location was assumed to be somewhere north of the Northumberland Strait, and the study based on the quality of the wind resource in the area (wave energy harvest is partly a function of surface wind speeds).

In a surface-following system, wave motion pressurizes hydraulic oil, and the pressure energy is subsequently converted into power through a specially designed hydraulic gear motor (in reverse).

Capital costs were based on scaling up a 2.25 MW wave power reference project located near Aguçadoura, Portugal. The wave energy converters in this project were located about 5 km off the Atlantic coast. Costs were based on 14 modules of 750 kW each and included the construction of a quayside facility for maintenance.

A significant project feature is the unit weight, which is approximately 1 tonne per kW covering sand ballast, floating vessels and hydraulic oils. Each module is approximately 750 tonnes. The hydraulic oils in the system are biodegradable; therefore, outside containment systems would not be required.

The cost estimate range for a wave power project is estimated to be -25 per cent to +75 per cent (relative to the baseline). As harvesting wave energy is technology specific, each technology has its own method of energy harvest, site-specific features and costs. All are considered "pre-commercial" at this time.

The O&M costs for wave power devices vary widely depending mainly on the technology, distance to the shore and wave intensity. However, the operation costs would be lower than for tidal devices because no divers would be required for inspection and maintenance operations. During maintenance, the surface-following devices are disconnected from their cabling and transported to a quayside facility. Typically, the wave power devices are modularized in order to allow quick removal and replacement operations without the need for large cranes or boats.

The project lead time for a surface-following wave converter would be approximately 12 to 18 months, depending on the capacity of the plant. The modules are commissioned separately on quayside, assembled, and then towed to site, where a final test is carried out. This process would take four to six weeks. This wave power plant would have an expected accounting life of at least 20 years; however, there is no proof of this with current technologies. Again, these figures depend greatly on the technology, tidal environment and operation conditions to which the devices are exposed, as well as on the maintenance schedule.

2.4 Combined Heat and Power

2.4.1 Biomass

How is electricity generated using biomass?

Biomass is defined as organic material derived directly from plants. It is produced through photosynthesis, the process used by plants to convert the sun's energy into chemical energy. This chemical energy can then be extracted from the biomass through combustion, to produce energy that can be used as heat or power. The optimum biomass option is a cogeneration option of steam and energy.

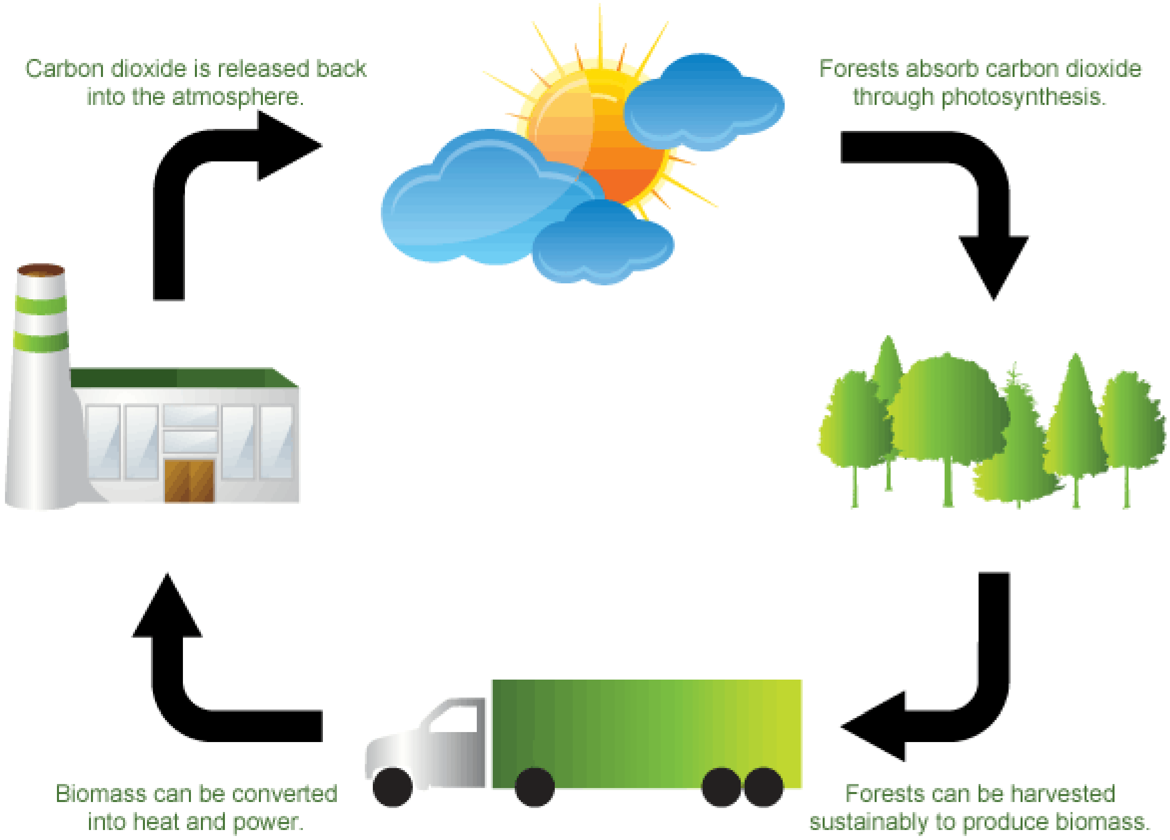
This generation option consists of a direct-fired biomass, combined heat and power (CHP) plant, with a net electrical output of 10 MW, and having the potential to supply a thermal output of 17 MW to an adjacent steam host. The plant would include a stoker grate boiler, a baghouse and a condensing steam turbine generator with a controlled extraction for the process steam supply. The condenser cooling system would include a multi-cell mechanical draft cooling tower.

The biomass stream was assumed to be wood waste with a gross calorific heating value of 6,800 Btu per lb. (15,788 kJ per kg) and a moisture content of 50 per cent. It was assumed that the wood waste would be sourced locally and delivered to the site via trucks with live bottom trailers. The site would include a wood handling and preparation area (screen and hogger). The plant configuration assumed a non-reheat rankine cycle with modest feedwater heating cycle and moderate main steam conditions (750 psig / 750 F).

In non-cogeneration mode (no steam host), the plant capacity would increase to 14 MW. Since this study did not identify a steam host, it was initially assumed that a non-cogeneration option would be evaluated. This would also provide the ranking of this supply option assuming electricity generation only. The economics would improve with consideration of a steam host as this would improve the thermal efficiencies of the system.

Biomass energy does not contribute to climate change in the way that energy derived from fossil fuels such as coal, oil and natural gas does. The carbon, which is stored in biomass material as it grows, is already part of the atmosphere. Biomass energy does not add new carbon to the active carbon cycle, unlike fossil fuels, which remove carbon from geologic storage. The carbon emissions from biomass facilities would have otherwise been released back into the atmosphere through some other fate or mechanism such as natural decay or an alternative disposal method like open burning. The advanced emissions controls on a biomass energy facility significantly reduce the amount of other emissions such as particulate matter.

Figure 23: Process for biomass



Biomass energy is considered a "zero-greenhouse-gas-emitting technology" by the Regional Greenhouse Gas Initiative RGGI in the Northeast U.S. and the EU Emission Trading Scheme (EU ETS).

The total project costs were estimated based on a factored cost methodology using Hatch in-house data and recent vendor quotes for wood-fired boilers.

The operational costs for this facility include operations and maintenance personnel, and management and administrative staff. For a plant of this size, 20 employees would be the minimum requirement for management, operations and maintenance staff.

The lead time for a project of this size would range from 30 to 36 months from the start of engineering to the commercial operation date. Permitting activities were not included in the above durations. The biomass plant would have an accounting life of 25 years.

2.4.2 Fuel Cells

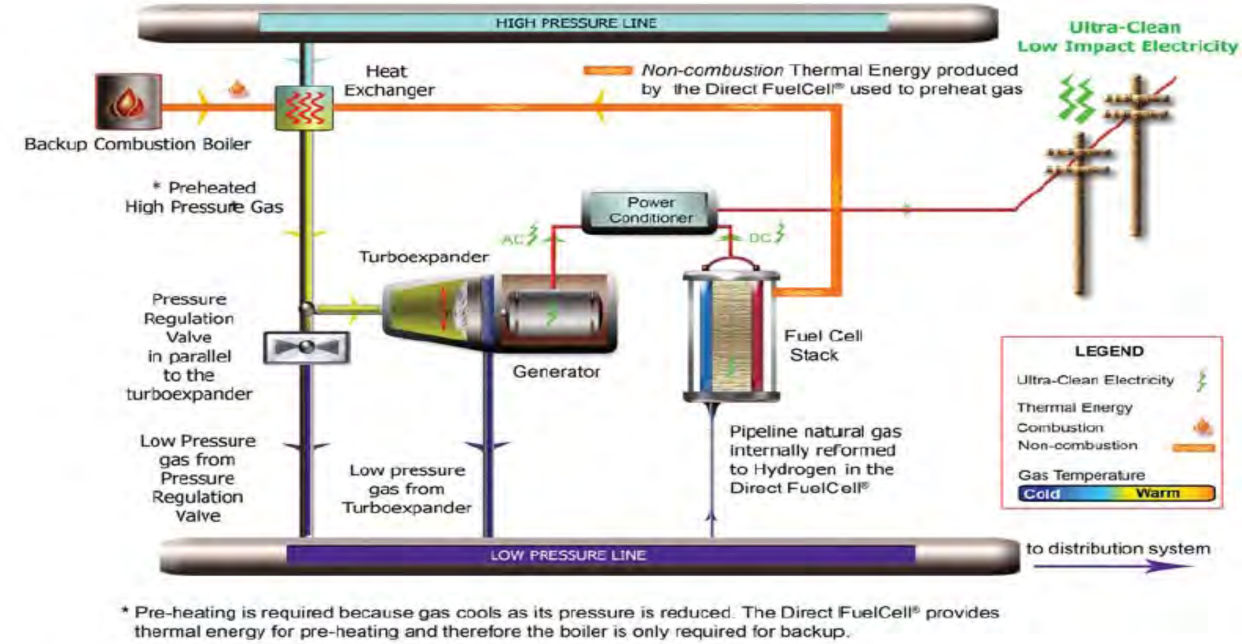
How is electricity generated using fuel cells?
Fuel cells work by catalysis, separating electrons and protons of the supply fuel, and forcing the electrons to travel through a circuit, hence converting them to electrical power. The waste produced from this process is typically simple compounds such as water and carbon dioxide. Fuel cells are different from conventional electrochemical cell batteries in that they use an external fuel such as natural gas or hydrogen.

Stationary fuel cells are typically installed in institutional and industrial facilities that can internally consume the power and heat generated. They are a combined heat and power technology with electrical conversion efficiencies exceeding 40 per cent. The heat load can be space or process heat, or heat to drive absorption chillers.

The construction of the Maritimes and Northeast Pipeline in 1999 provided end users in New Brunswick who were planning an upgrade of their utility plants with the option of using natural gas, which is also the feedstock for the two leading commercial fuel cell technologies on the market today. Fuel cells have also been installed in sewage treatment plants (running on digester gas), and have been installed as backup power in data and telecommunications centres.

Figure 24 illustrates a fuel cell being installed to generate power and heat in a gas letdown station in which gas pressures are recovered by the pressure reduction from mainline levels to distribution levels.

Figure 24: Fuel cell application



Capital costs for a 1 MW plant were estimated for this study. Costs were based on the supply of 4 x 250 kW fuel cell modules utilizing molten carbonate fuel cell technology (MCFC) by Fuel Cell Energy. The other commercial technology for utility scale plants is UTC Power's phosphoric acid fuel cell (PAFC). A 1 MW plant based on PAFC technology would consist of five UTC Power PureCell 200 modules.

One benefit of PAFC over MCFC is that the former does not require a continuous stream of water for the process (which also requires demineralization).

It was assumed that natural gas would be available at adequate pressures (<0.1 bar (g)) to support operation at base load under all site-ambient conditions without on-site gas booster compressors.

There are a number of factors that affect the capital cost estimate accuracy. These include equipment costs, as well as costs associated with interfacing with the heat distribution and electrical systems at a host site. Fuel quality and the amount of fuel conditioning can also vary from location to location on a continental basis, but within New Brunswick would need nearly the same requirements throughout (the exact details of these requirements were not determined in this study).

For this cost and technology review, the MCFC was selected due to:

- higher power production efficiencies (lower heat rate);
- higher temperature waste gas, of the order of 370°C (can be used in a wider variety of heating applications);
- lower estimated capital costs versus PAFC costs; and
- Canadian application experience (Enbridge).

Fuel cell plants in general require little or no site work due to their relatively small footprint. Most installations in the 200 kW to 1 MW range are located in the yard or parking area of an end-user's site or are installed on rooftops. Fuel cells located indoors require additional ventilation considerations (not assumed in the cost profile). Auxiliary costs for all fuel cell types include a heat recovery unit and piping (to/from a heat sink), and a small nitrogen facility (bottles or liquid form – for start-up, and desulphurization catalyst change-out). Fuel cells cannot "black start" and require utility power feeds or a diesel generator to start them up.

Fuel cells require about three days to warm up and are normally kept on warm standby when their power production is turned down. During start-up, the fuel cell is back-fed power from the utility (about 50 kW). Fuel cell plants typically run unattended. Water treating reagents associated with the molten carbonate technology require periodic refilling and system monitoring. Fuel cell vendors offer service agreements that include remote monitoring.

The other plant consumables are catalysts for desulphurization and Carbon monoxide (CO) shift (part of the reforming operation); these require replacement every three years or so, depending on the sulphur content of the fuel and on utilization.

Project lead time would be approximately 9 to 12 months after receipt of order. Including up-front studies and preliminary engineering, project implementation would take approximately two years. To date, one utility-scale project has been implemented in Canada by FuelCell Energy. From a project implementation perspective, this means that issues related to Canadian codes and standards have been overcome (the product in this case is FCE's 1500 series, 1.4 MW fuel cell in an application that recovers pressure energy from gas pipelines developed in alliance with Enbridge – shown in Figure 25). Construction and commissioning would take approximately two months.

The main capital replacement issue over the project's lifecycle is the replacement of the fuel cell stack (the membrane) every five years, at a cost of about one-third of the original equipment cost.

This fuel cell plant would have an accounting life of approximately 20 years. Of the commercial plant profiles reviewed (those 200 kW or above), the longest-in-service was approximately 10 years. Steam reformer lifecycles routinely exceed 20 years (with periodic catalyst and reformer tube changes), as there are relatively few moving parts.

As mentioned above, the stack replacement is a major project lifecycle issue and has been addressed somewhat by UTC Power with their recent launch (late 2008) of their 400 kW model, which has a projected stack life of 10 years, compared to Fuel Cell Energy's five years (which formed the basis of the costs in this review). UTC Power does not have any Canadian fuel cell installations.

Figure 25: Fuel Cell installation at a brewery, 4 x 250 kW modules, from FuelCell Energy

2.4.3 Microturbines

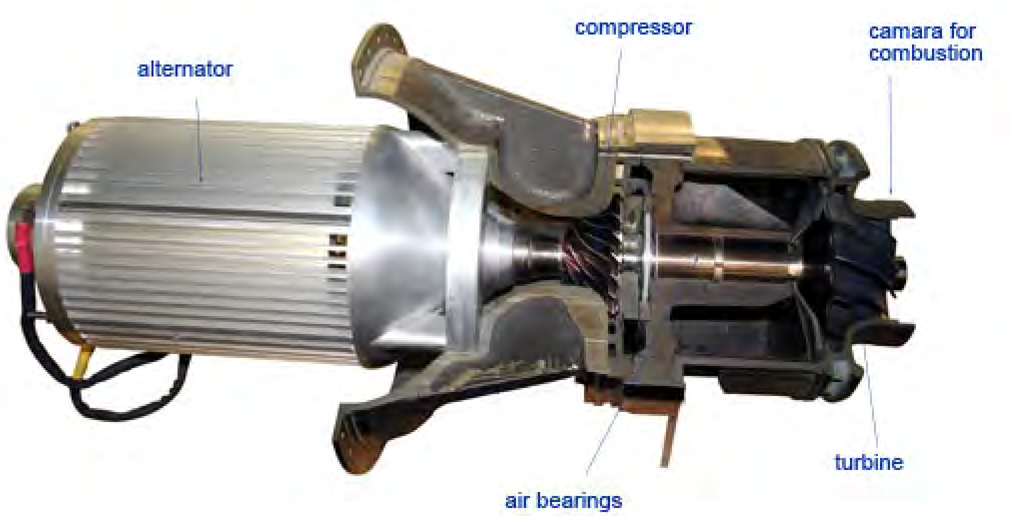
How is electricity generated using microturbines?

A microturbine is a small version of a combustion turbine. An air/gas mix is ignited in a combustion chamber and the resulting gas flow is directed to the blades of a turbine which turn a shaft. The rotating shaft is connected to an electrical generator which converts the rotating shaft motion into electrical energy.

Microturbines are used in niche applications where CHP is required, and are used mainly as distributed generation (DG) resources. The generation option considered in this study is a nominal 1 MW natural gas fired micro-turbine based. Several installations could be considered in communities or businesses where natural gas is available.

Packaged microturbines are typically considered to be in the range of 30 kW to 1 MW and are available from a number of manufacturers including Allied Signal Power Systems, Bowman Power Systems, Capstone Turbine, Elliot Energy Systems, NREC (Ingersoll-Rand) and Turbec (Volvo/ABB). For this study, the plant is assumed to consist of one 1 MW unit as manufactured by Capstone. This manufacturer is prominent in the microturbine field.

Figure 26: A typical microturbine



The system would be capable of operating in grid-connected mode and in islanded mode. The microturbine, with its low emissions, low maintenance requirements and high reliability, is well suited for combination peak-shaving and standby power applications as well as small-scale combined heat and power plants. Site average performance was estimated based on an elevation of 8 m AMSL and annual average temperature of 5.5°C.

Post-combustion emissions controls were not included (i.e., CO catalyst or NO_x catalyst) as many microturbines emit less than nine ppm of NO_x (ref.15 per cent O_2) (<0.49 lb. per MWh) at full load.

It was assumed that pipeline gas would be available at adequate pressure (6 bar (g)) to support combustion turbine operation at base load without on-site gas booster compressors.

The overnight total project costs were estimated based on a factored cost methodology using Hatch in-house data and recent vendor quotes for the major equipment.

Non-fuel variable O&M costs were estimated from EPRI technical reports. The costs were based on comprehensive maintenance packages being offered by microturbine packagers, and include all parts and labour.

The project lead time would be 1 year. This microturbine plant would have an accounting life of 25 years.

2.5 Biomass Bubbling Fluidized Bed

How is electricity generated using biomass bubbling fluidized bed?
Fluidized beds suspend solid fuels such as biomass on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids. The tumbling action, much like a bubbling fluid, provides more effective chemical reactions and heat transfer. The heat produces steam that drives a steam turbine connected to a generator, which then produces electricity.

This generation option is for a nominal 50 MW biomass bubbling fluidized bed (BFB) thermal power plant. The reference plant would be a one-on-one arrangement based on one boiler with bubbling fluid bed combustion technology and one condensing steam turbine generator. The facility would process approximately 2000 tonnes per day of wood.

The plant location is assumed to be a green field site on the seacoast with an elevation of six to eight metres above sea level. The plant would employ a once-through seawater cooling system. The fuel for the plant is assumed to be wood with a maximum moisture content of 50 per cent and a heating value of 6,800 Btu per lb. (15,788 kJ per Kg) (HHV). It is assumed that the wood waste is sourced locally and delivered to the site via trucks with live bottom trailers. The site includes a wood handling and preparation area (screen and hogger).

The BFB combustion process and control results in low NO_x and CO. Sulphur emissions are managed by utilizing low-sulphur biomass feedstock. It is not anticipated that post-combustion emissions controls would be required and these are not included.

The total project costs were estimated based on a factored cost methodology using Hatch in-house data for recent projects. The cost estimate reflects an EPCM contract strategy. The total project cost does not include owner’s costs.

The cost of the plant includes one (1) BFB boiler, one (1) steam turbine generator, and all auxiliary and ancillary equipment required for the thermal cycle. The scope also includes a generator step-up transformer; a switchyard; a water treatment plant; biomass handling equipment from the truck unloading point to the boiler house, including a biomass stockyard, stacker and reclaim system; light and heavy oil fuel systems for ignition and warm-up, including storage; and office and maintenance facilities.

Hatch has made the following assumptions:

- power from the power distribution grid will be available to start the plant;
- the plant will have access to deep seawater requiring a short cooling water intake and outfall;
- biomass will be delivered by truck;
- fresh water will be available to the plant for cycle make-up and other water needs; and
- oil fuel will be supplied by truck.

Figure 27: 50 MW biomass bubbling fluidized bed plant located in France

2.6 Municipal Solid Waste

How is electricity generated using municipal solid waste?
Waste-to-energy plants burn municipal solid waste (MSW) to generate electricity or heat. At the plant, MSW is unloaded from collection trucks and shredded or processed to ease handling. The waste is fed into a combustion chamber to be burned. The heat released from burning the MSW is used to produce steam, which turns a turbine to generate electricity.

This generation option is for a nominal 50 MW municipal solid waste thermal power plant. The reference plant would be a three-on-one arrangement based on three refuse boilers and one condensing steam turbine generator. The facility would process approximately 2,000 tonnes of waste per day.

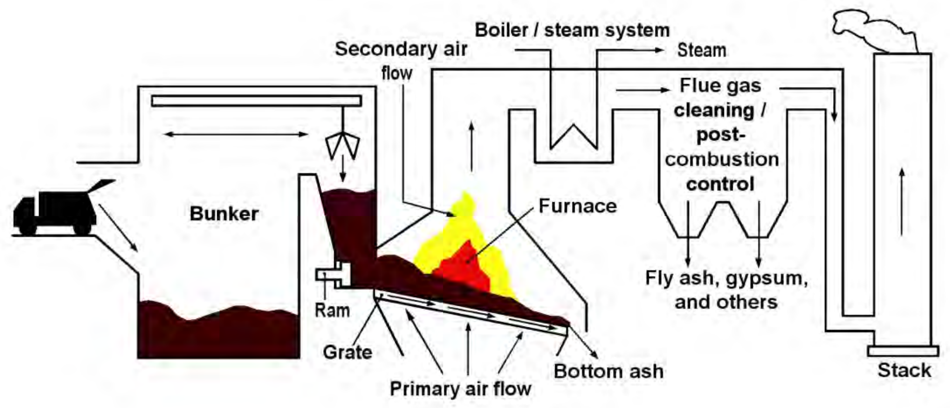
The plant location is assumed to be a green field site on the seacoast with an elevation of 6 to 8 meters above sea level. The plant would employ a once-through seawater cooling system. The waste for the plant is assumed to have a heating value of 5,300 Btu per lb. (12,305 kJ per Kg).

The cost of the plant includes three MSW boilers, one steam turbine generator, and all auxiliary and ancillary equipment required for the thermal cycle. The scope also includes a generator step-up transformer; a switchyard; a water treatment plant; waste handling equipment from truck to boiler house, light and heavy oil fuel systems for ignition and warm-up, including storage; and office and maintenance facilities.

Assumptions:

- power from the power distribution grid will be available to start the plant;
- the plant will have access to deep seawater requiring a short cooling water intake and outfall;
- waste will be delivered by truck and unloading provisions have been included;
- fresh water will be available to the plant for cycle make-up and other water needs; and
- oil fuel will be supplied by truck.

Figure 28: MSW combustion plant



2.7 Solar Photovoltaic

How is electricity generated using solar energy?

Solar energy can take the form of photovoltaic or thermal energy. Incident solar radiation (sometimes called "insolation" for short) can be converted into electricity directly, using photovoltaic (PV) cells.

Solar irradiance consists of direct radiation (between the sun and the point of interest), and diffuse radiation, which is received from all directions after being scattered by the atmosphere, or redirected by a cloud cover. The total irradiance varies as a function of time throughout the day (peaking at midday), and varies seasonally, with the angle of the sun in the sky peaking at the summer solstice. In addition to the daily and seasonal variability, the energy source is also intermittent, primarily as a function of air mass and cloud cover.

Figure 29 shows New Brunswick's average annual daily photovoltaic potential. Figure 30 summarizes the average solar resource available for a typical year in three cities in New Brunswick. Data for the chart and table was gathered from Natural Resources Canada.

Figure 29: New Brunswick's photovoltaic potential

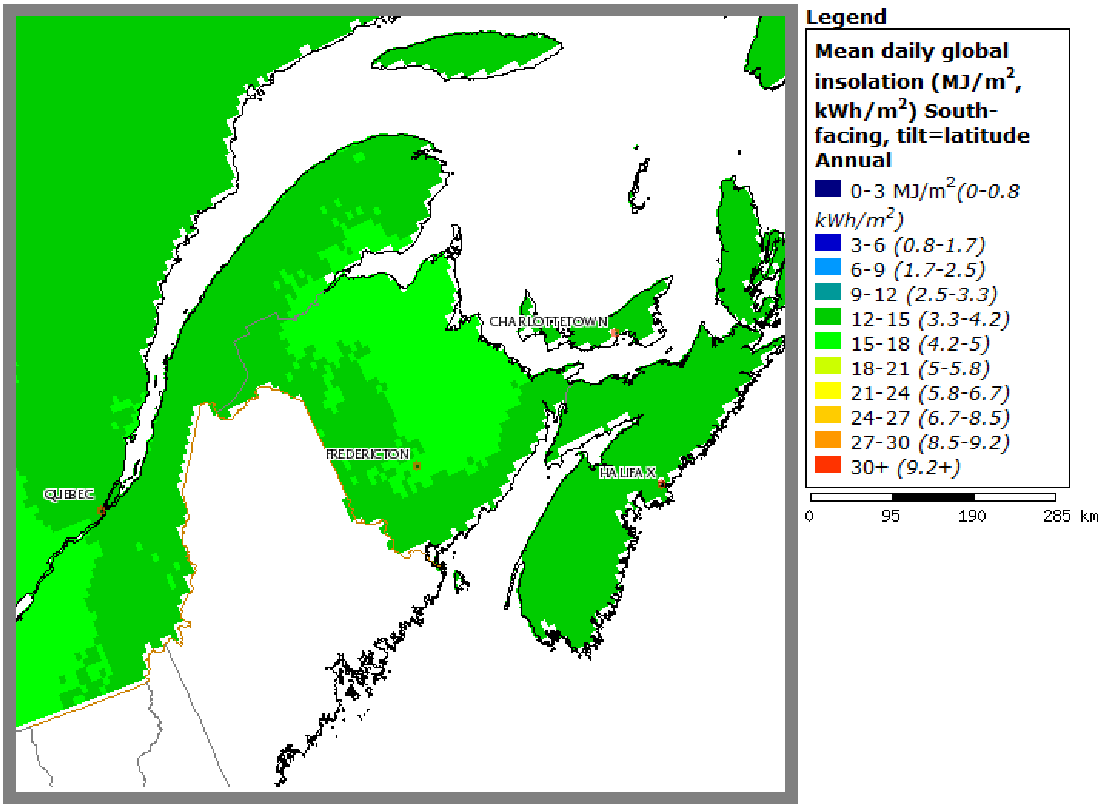


Figure 30: Photovoltaic potential in three cities in New Brunswick

City	South-facing Tilt = Latitude Solar Resource
Fredericton	1,530 kWh/m^2/year
Saint John	1,510 kWh/m^2/year
Miramichi	1,560 kWh/m^2/year

Incident solar radiation can be converted into electricity directly (using photovoltaic (PV) cells) or indirectly (first converting the radiant energy to mechanical energy by thermal means).

PV panels (or "modules") are capable of converting both types of incident radiation to electricity, and can therefore produce electricity even during periods dominated by diffuse radiation (cloud-covered skies). PV modules use a silicon semi-conductor material to directly convert solar radiation to direct current (DC) electricity. The most common implementation of solar cell technology is the grouping of monocrystalline or polycrystalline cells to create panels. A panel is typically composed of 60 or 72 cells, mounted to a glass surface using an epoxy, and then laminated with a plastic backing material. Monocrystalline is the most mature of the photovoltaic technologies. The cells are created from single crystals sliced into wafers and are the most expensive and the most efficient, achieving module efficiencies up to 22 per cent. Monocrystalline panels are often in applications where space constraints exist such as rooftop installations. Polycrystalline cells are comprised of multiple crystalline structures created by melting silicon in a mold and then creating wafer slices. They can achieve efficiencies up to about 17 per cent and are generally less expensive on a dollar per watt basis than monocrystalline, although the cost differences have become narrower in recent years. Combined, the various crystalline technologies comprise of approximately 90 per cent of the global PV module market.

PV panels can also be manufactured using thin film technology, consisting of a thin layer of semiconductor material directly deposited on a glass substrate via vapour deposition. The manufacturing process for thin film cells is less costly than that of crystalline cells. Thin film panels have been traditionally regarded as a less efficient technology compared to crystalline modules, however recent innovations in this area have resulted in independently verified module efficiencies of up to about 18 per cent in a test setting. Modules using this technology are not yet commercially available, but will potentially be competitive with crystalline technologies. Thin film technologies also perform better in high temperature environments due to a better thermal coefficient. Thin film technology has approximately 10 per cent of the global market for PV modules, but has very little presence in Canada.

Theoretical efficiency of lab-made cells has been increasing, but the efficiencies of commercially available cells have not changed significantly over the last several years. Over time, it is expect that efficiencies will improve as the lab-made cells progress into mainstream commercial manufacturing.

PV power plants consist of PV modules wired together in series to make up a string, with strings connected in parallel to comprise a solar array. The parallel strings direct the DC electricity produced by the cells to an inverter that converts it to alternating current (AC) power, synchronized with the grid. Inverters include power electronics that continuously monitor and modify solar array voltage to maximize power production. Solar arrays can either be mounted on a fixed support structure at an angle selected to optimize annual production, or on a one or two-axis tracking system that follows the sun throughout the day. A tracking system increases the annual energy yield due to an increased aperture area, and decreased reflection losses that occur at high solar incidence angles; however, they increase the capital and operational costs, and are less effective in areas with high amounts of diffuse radiation.

Based on the solar resource available in New Brunswick, the current CAPEX analysis was based on a PV solar plant mounted on a fixed support structure, at an angle optimizing annual energy production. An additional option was also included in this analysis that represented a single axis tracking system where comparison of different racking technologies could be made.

Two plant sizes were considered in this study, 10 MW and 25 MW. These two plant sizes would generally both represent a large-scale PV plant. Although slight economies of scale would be realizable with the 25 MW plant, the capital costs would essentially be equal on a per kW installed basis.

Figure 31: A 12 MW PV facility located on cropland in Germany

Cost estimates for the PV plants were based on Hatch in-house data and publically available cost data from industry from NREL (National Renewable Lab) in the USA.

The cost estimates include everything from the onset of the engineering phase to connection of the plant to the grid. A summary of the assumptions used follows:

- PV plant is grid connected with no battery storage;
- 10 MW plant based on fixed tilt racking;
- 25 MW plant based on fixed tilt racking;
- 25 MW plant based on single axis tracking; and
- The arrays use similar balance of plant equipment (central inverters crystalline modules etc.).

Items excluded from the estimate are as follows:

- Cost of land. Land budgets range from 1.8 ha (4.4 acres) per MW for fixed racking and polycrystalline technology, to 2.2 ha (5.4 acres) per MW for single axis tracking (includes maintenance space between arrays but not land that cannot be used due to site features such as drainage paths). Lands proposed for solar projects are typically deforested.
- Transmission line to point of interconnection (POI) and substation at POI. It should be noted that this can vary greatly, based on jurisdiction and grid capabilities. In Ontario, interconnections costs for projects built or under construction can range from $500,000 to more than $8,000,000.
- Geotechnical conditions unfavourable to the installation – the cost of installation of solar plant is in part dependent on the civil/geotechnical aspects of the site. The installations with lowest cost involve installation in soil that allows for driven pile construction. Sites with bedrock near the surface (that may need rock trenching), or unstable gravel soils that require caissons, can increase the cost of installation.

The cost of PV panels has continued to decline as global production continues to scale up and the technology continues to improve. Price reductions also continue to occur in balance of plant components such as inverters and tracking, as they are a proportionally larger component of the cost. Unfortunately the falling value of the Canadian dollar relative to the American dollar has significantly offset the decrease in costs. An exchange rate of 0.85 USD – 1.00 CAD was assumed for the purpose of the estimate used in this analysis. These values were developed from estimates for utility scale projects at Hatch and industry wide surveys of PV installations in the United States.

Going forward, higher DC voltages have been proposed to decrease cable sizing and increase efficiency of inverters with 1,000 volts now standard in most jurisdictions and 1,500 volts gaining traction.

The two main types of operation and maintenance costs (O&M) methodologies are usually labeled “preventative” and “reactive” maintenance. Preventative maintenance involves a regime of regularly scheduled activities including inspections, cleaning and minor repairs or equipment replacements. The goal of this methodology is to prevent issues before they occur and to minimize unscheduled visits, repairs and downtime. Reactive maintenance, on the other hand, relies heavily on detailed monitoring and fixing issues as they occur. This is sometimes referred to as the break-fix model. The goal of this strategy is to minimize maintenance cost by only repairing on an “as-needed” basis.

O&M costs can vary significantly between solar facilities depending on a variety of factors. One survey conducted by NREL of utility scale plants in the US found that total O&M costs range from $9–$33 per kW per year (NREL 2016). For sites of the size described in this analysis, it is expected O&M cost to be approximately $21 per kW per year with an additional $6 per kW per year as a reserve for the expense of replacing the inverters every 10 years on an amortized basis, due to the shorter lifespan of the inverters versus solar panel lifecycle. This reserve is the equivalent cost of purchasing inverters with 20-year or more warranties. This translates to $27 per kW per year for all solar facilities.

Some tracking technologies may also increase the O&M costs, but the single axis tracking market has moved towards maintenance free technologies with fully enclosed drive systems. Unscheduled maintenance would still be required in the event of a breakdown, but no periodic lubrication or other tasks are necessary.

The typical development time frame, from concept to on-line date (lead time), is relatively short for PV power plants. Procurement and installation time varies with market conditions but can be expected to take 6 to 12 months. Including the engineering phase, lead times of 18 to 24 months are estimated for the 10 MW and 25 MW projects respectively (not including environmental screening and utility connection studies).

The expected service life of the PV plant is estimated to be 30 years. Typically, solar panels have a 25-year limited warranty on power output, which includes 90% power output assurance for the first 10 years and 80% power output assurance for the remainder of the warranty period. This is frequently stated by manufacturers as a linear warranty rather than the steps. It is expected that the panels will continue to operate with a reasonable power output for at least 5 years longer than the stated warranty.

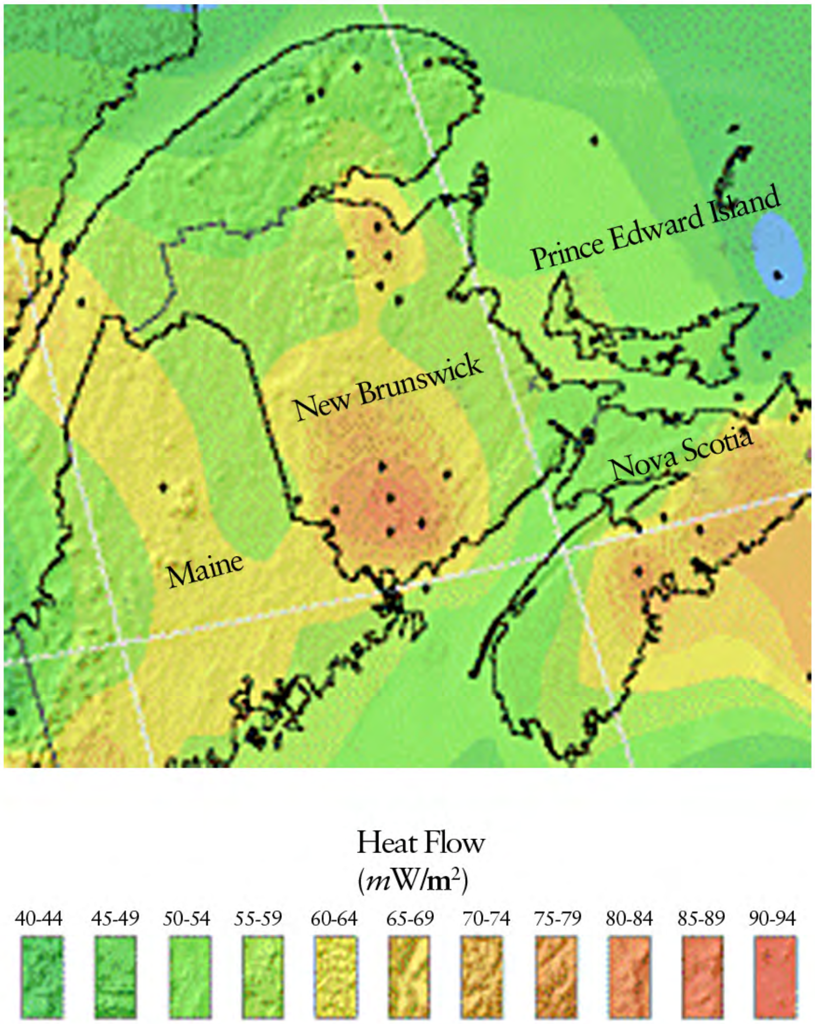
While the overall service life of the plant is stated above, it is noteworthy that the inverters will typically wear out before the end of the service life of the plant and need to be replaced or overhauled, as previously stated. It is noted that this cost has already been accounted for in the operation expenses estimate.

2.8 Enhanced Geothermal

How is electricity generated using enhanced geothermal?
Enhanced geothermal systems inject cold water under high pressure into underground rock formations. This water travels through the fractured rock capturing heat until it becomes very hot and is forced to the surface through a second borehole. A steam turbine and generator can be used to convert the energy in the heated water to electricity.

Geothermal energy originates from natural heat in the earth that is trapped close enough to the surface to be extracted economically. This energy resource is considered renewable, sustainable and reliable over the long term. From the geothermal mapping of North America (American Association of Petroleum Geologists, Figure 32), New Brunswick has modest geothermal potential, particularly in the southwest near Fredericton and the northeast near Bathurst.

Figure 32: Enhanced geothermal potential in New Brunswick

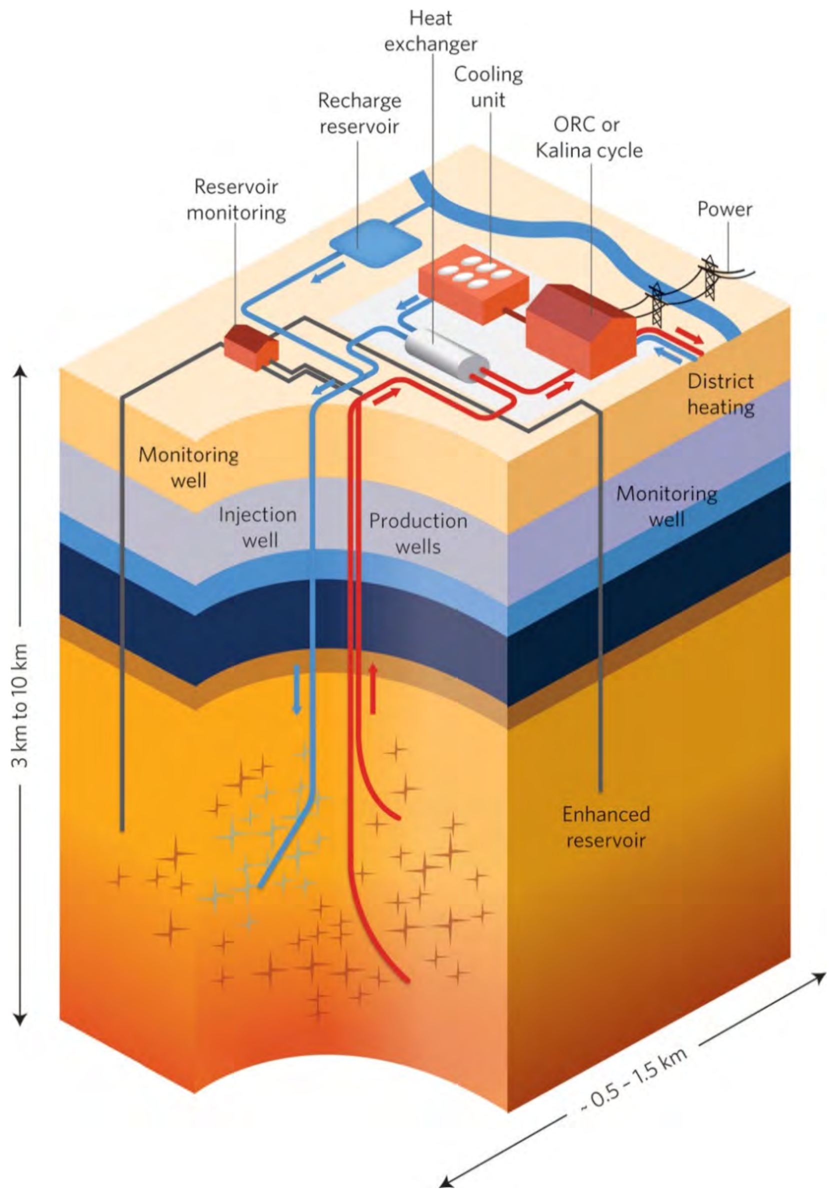


All of the commercial geothermal power plants are based on transferring geothermal water to the surface, where the heat energy is converted into electricity at a geothermal power plant. There are three commercial types of geothermal power plants:

- dry steam power plants – drawing from underground resources of steam;
- flash steam power plants – this is the most common and using geothermal reservoir of water with temperatures greater than 182°C; and
- binary steam power plants – that operate on lower water temperatures of about 107°C to 182°C.

In addition to the above-mentioned technologies in use today, additional geothermal applications and technologies are being developed. For example, two types of geothermal resources can at present be used in binary cycle power plants to generate electricity: enhanced geothermal systems (EGS) and low-temperature or co-produced resources. The most commonly discussed method is EGS, as shown in Figure 33, which has the potential of dramatically expanding the use of geothermal energy. EGS provides geothermal power by tapping into the Earth's deep geothermal resources that are otherwise not economical due to lack of water, location or rock type. This method's concept is to extract heat by creating a subsurface fracture system to which water can be added through injection wells. Improving the natural permeability of rock will create an enhanced or engineered geothermal system. Injected water is heated as it contacts with the high temperature rock and returns to the surface through production wells, as in naturally occurring hydrothermal systems.

Figure 33: Enhanced geothermal system



Low-temperature and co-produced geothermal resources are typically found at temperatures of 150°C or less. Some low-temperature resources can be harnessed to generate electricity using binary cycle technology. Co-produced hot water is a by-product of oil and gas wells.

For this project, capital costs are estimated for a 30 MW power plant and were based on the average costs of the binary and flash technologies, which were collected from the Staff Draft Report of the California Energy Commission (CEC)[26], released on May 2014. However, it is understood that more information about the nature of the resource is required in order to narrow down technology suitability for applications in New Brunswick. Nevertheless, the majority of a geothermal project's cost is the power plant (about two-thirds) due to the relatively low temperatures of the geothermal resource (in New Brunswick, estimated to be about 180-200°C at 6 km depth).

The costs of developing a geothermal power plant are comprised of exploration, resource confirmation and characterization (drilling and well testing), and site development (facility construction). These estimates were based on geothermal power plant construction in western US states.

A summary of the cost estimate assumptions are as follows:

- the costs of developing a geothermal power plant in CEC Draft Staff Report are average costs for the two technologies analyzed;
- the cost estimates in the CEC report are based on developing a 30 MW power plant, which corresponds to our selected size of 30 MW; and
- cooling water would be readily available.

Costs are estimated to range from -30 per cent to +40 per cent relative to a baseline cost. The cost range has three main contributing factors:

- the extent of exploration required to identify and harvest a geothermal resource;
- the costs associated with different harvest technologies (site specific); and
- the trade-offs associated with going deeper into the earth to obtain higher temperatures versus the power plant costs.

Operation and maintenance costs encompass all expenses related to the operation and maintenance of the power production equipment (including generator and turbine), the collection system (field pipes) and vehicles. The costs related to steam field renewal were also included and are discussed in more detail below.

Project lead time for most geothermal projects would be three to five years. A geothermal power plant would have an expected accounting life of at least 30 years.

[26] http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf

It is important to note that some components would typically wear out before the end of the accounting life and would need to be replaced or overhauled. The most important components that require replacement in geothermal power plants are production and injection wells.

The well productivity decline is a complex phenomenon mainly explained by the pressure and/or temperature drop of the reservoir. Make-up drilling aims to compensate for the natural productivity decline of the project start-up wells by drilling additional production wells. This operation could be considered as the geothermal "fuel" cost. The annual maintenance and make-up drilling costs correspond to approximately 5 to 7 per cent of the initial drilling costs.

2.9 Pumped Hydro Storage

How is electricity generated using pumped hydro storage?

Pumped storage is a variation of hydroelectric power generation, which utilizes the difference between on and off peak electricity in the project's economic evaluation. Pumped storage uses low cost, overnight electricity to pump water from the tailwater pond back up into the reservoir; during the peak periods during the day, this water is then used to generate electricity that is sold at a higher price.

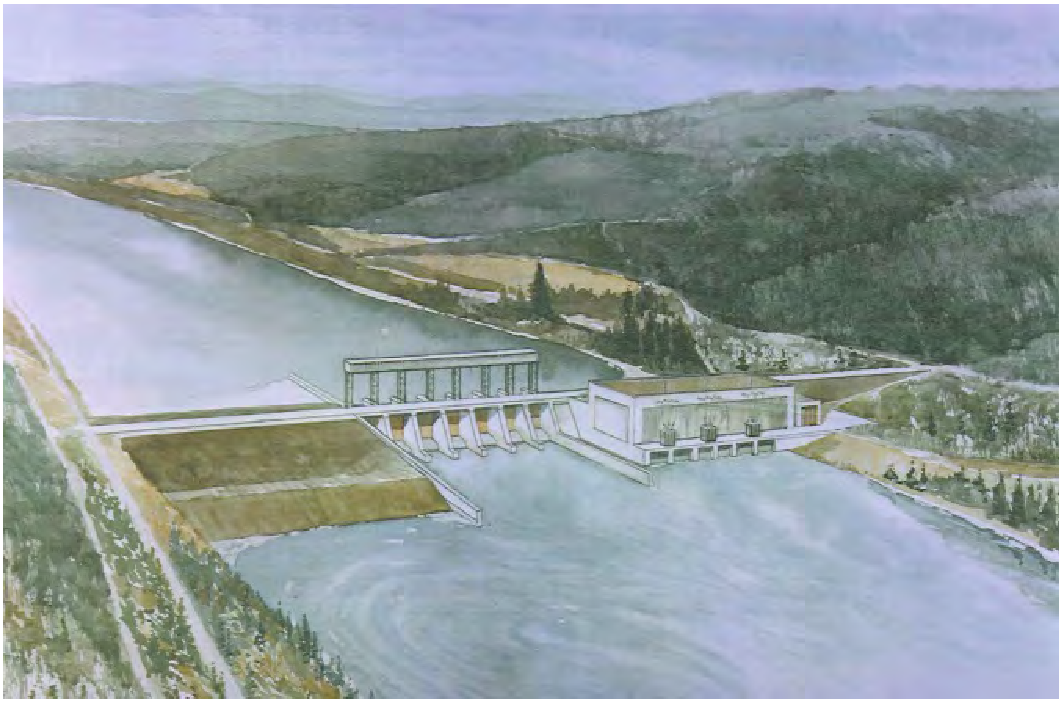
NB Power currently owns and operates seven hydro generating stations, one of which—the Grand Falls Generating Station—has been investigated as a potential site for pumped storage.[27] More recently, Hatch studied the addition of a new 100 MW powerhouse at the Station. For more information, refer to Section 1.5.1 (Grand Falls Additional Power).

In the case of a pumped hydro scheme, the development at the existing Grand Falls Generating Station would consist of a 100 MW pump turbine instead of a normal hydro turbine. Also, a lower reservoir would be developed to provide a sufficient volume of water to be pumped into the upper reservoir. This could be accomplished by constructing a dam with spillway at a suitable distance downstream of the Grand Falls facility and impounding the upstream water to create sufficient water to be stored. This entire scheme can be seen in Figures 34 and 35.

[27] "Grand Falls – Morrell Integrated Pumped Storage Project", 1989, New Brunswick, Canada, Acres International P8472.

Figure 34: Artist's rendition of the pumped hydropower project at Grand Falls

Figure 35: Artist's rendition of the hydro station to provide storage for pumping



For purposes of this study, the total costs for a 100 MW pumped storage plant were estimated. Costs from Grand Falls new supply study were used directly (base costs) and the incremental costs were estimated.

The incremental costs were based on installing pump-turbine equipment in the proposed new 100 MW powerhouse at Grand Falls (instead of turbines only) and adding a lower reservoir. All of the other new facilities (intake, penstock, surge tank and spillway) can be used as described in Section 1.5.1 (Grand Falls Additional Power).

The lower reservoir is required to provide a sufficient volume of water for pumped storage operation during periods of low river flow. This could be accomplished by constructing a dam with spillway a suitable distance downstream of the Grand Falls facility and impounding the upstream water to create sufficient live storage. However, with this approach the difference between the level of the impoundment (elevation ~95 m) and the river (elevation ~90 m) would represent lost energy, even when Grand Falls was operating strictly in the "conventional hydro" mode. Construction of a separate low head hydro facility at the impounding dam would be necessary to recover this energy. An alternative would be to have a separate lower reservoir isolated from the river into which the pump-turbine could discharge during pumped storage operations. The pumped storage plant would also be designed to discharge (along with the conventional hydro units) directly into the river during periods of higher river flow.

Lower reservoir costs will vary with retention capacity. The lower reservoir can be constructed within the existing river ("split" river arrangement), next to the river and close to the plant, or some variation in between. Hatch estimates that for every hour of live storage, approximately 1.25 million m^3 is required assuming zero natural river inflow; at 6.6 m depth, that's 189,000 m^2). This study did not assess if this was feasible; it only presents the idea as an alternative to the previous Grand Falls/Morrell Integrated Development concept where the lower reservoir consisted of the entire river from Grand Falls to Morrell, and was raised by approximately 4 m at the Grand Falls tailrace, resulting in a head loss of 10 MW at the existing Grand Falls Generating Station.

For pumped storage plants, the costs of reservoirs are site specific; in other recent pumped storage studies, costs were \$3 to \$40 per m^3 live storage. Assuming \$20 per m^3, the cost of the reservoir with four hours live storage would be \$100 million.

The other element of incremental cost, compared to the 100 MW addition at Grand Falls, was the increase in capital cost for the powerhouse to allow for:

- the physically larger pump-turbine machinery (as compared to a conventional turbine);
- motor starting equipment and reversing switches, etc.;
- the civil costs for the slightly larger powerhouse, which has a deeper setting to accommodate the increased submergence requirements for pumping operation; and
- facilities to allow the pump-turbine to discharge either to the river or the reservoir.

The cost increase is estimated to be approximately 40 per cent of the total powerhouse costs of the base powerhouse. The cost increments for the added pumped storage features range between -25 per cent and +65 per cent.

O&M costs for pumped storage facilities in the US are estimated at $18 per kW [EIA 2013]. Adjusted to 2016 price levels the cost is $19.70 per kW. Translating this to a pumped storage installation at Grand Falls, the annual O&M costs are approximately $2,000,000. The EIA information also indicates that pumped storage O&M costs are approximately $4 per kW higher than for conventional hydro.

Operating costs do not include the cost of electricity for pumping (similar in concept to "fuel"). These costs have a number of variables related to timing of the pumping operation and NB Power's internal cost structure. Energy consumption is estimated at 58.4 GWh per year (75 per cent cycle efficiency, 5 per cent capacity factor basis).

Hydro and pumped storage stations have similar lifecycles with the exception of the pump turbine, which typically has a slightly decreased life span relative to conventional hydro due to its nature of operation (increased wear on bearings, bushings and seals). The anticipated design life of a pumped storage hydro facility varies from 40 to 70 years; the service life of the pump turbine is anticipated to be 60 years, with major refurbishment every 20 years. Capital refurbishment costs can range between 30 to 50 per cent of the original cost of the hydraulic machinery in a major renewal. Given these rules of thumb, the capital renewal portion of OPEX costs are estimated to be $27 per kW per year[28] (present value basis spread over 20 years). Compared to the base plant, the lower reservoir is the main addition to the overall project.

2.10 Compressed Air Energy Storage

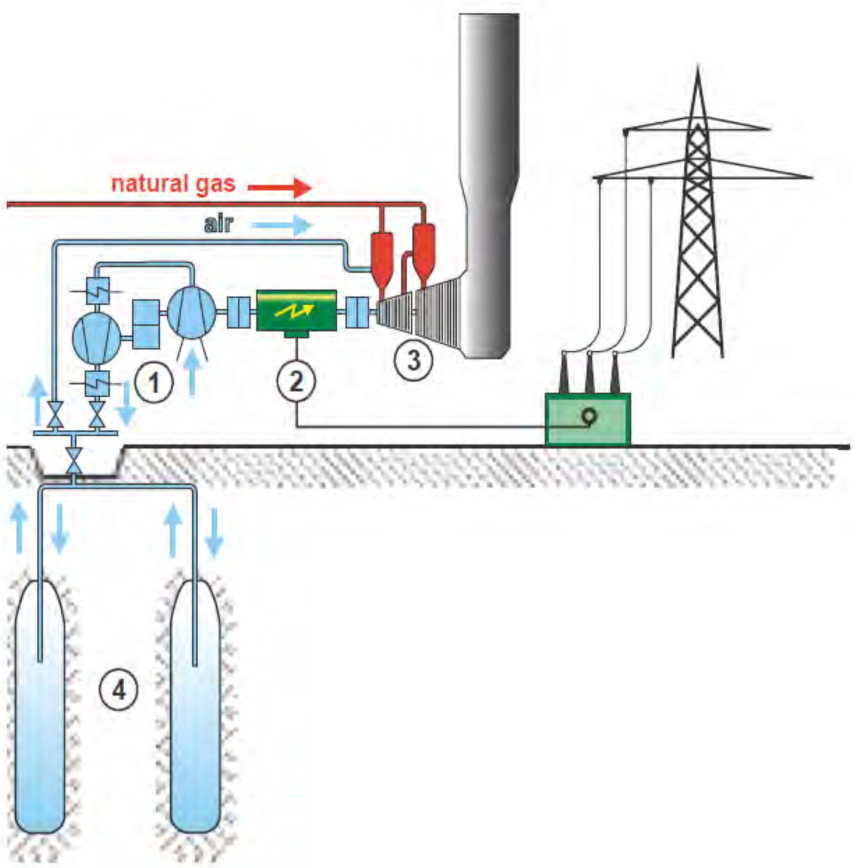
How is electricity generated using compressed air energy (CAES) storage?
CAES commonly uses a compressor during off peak hours to store air in an underground cavern or an above-ground tank. When electricity is required, the compressed air is released through a recuperator, increasing in temperature, and ignited with natural gas to rotate a turbine. The rotating shaft of the turbine is connected to a generator which converts the energy of the shaft into electrical energy.

A typical CAES plant consists of an injection compressor, a storage facility and a fired expansion turbine. The typical arrangement is a single train with the compressor and expander each connected to a common motor/generator via a clutch.

[28] Machinery cost is the sum of $970/kW (base plant) + 380/kW (pump-turbine/motor-generator features) = $1350/kW x 40% capital renewal spending = $27/kW/yr (20 year basis). For incremental O&M, charge $4/kW to the pumped storage function.

High-pressure air is typically injected into a storage reservoir in an underground geologic formation such as a saline aquifer or abandoned mine for large-scale CAES applications (although it is possible to use surface piping systems and reservoirs, these are usually impractical due to high costs). Storage pressures typically range from 50 to 80 bar (g), and limits will depend on the storage reservoir site-specific characteristics such as depth and geology. The simplified CAES system considered for this study is shown graphically in Figure 36.

Figure 36: A simplified compressed air energy storage system
(1. Compressor, 2. Motor/Generator, 3. Turbine, and 4. Storage Reservoir)



In storage mode, electricity from the system (2) drives a motor to compress air at high pressure (1), which is then stored in the storage reservoir (4).

In generation mode, the stored high-pressure air from the storage reservoir (4) is delivered to the combustors where heat is added prior to the turbine (3), which drives the generator to produce electricity (2). To increase efficiency, a recuperator is added to recover heat from the turbine exhaust to preheat the air withdrawn from the storage facility upstream of the combustor.

CAES systems are mainly used for energy storage and as backup for wind. Although the CAES system uses about 70 per cent less natural gas than regular combustion turbines, there may be associated costs to compress the stored air, depending on the source of electricity. The costs could be as low as zero if sourced from wind generation. Normally the costs are associated with off-peak electricity prices. This study assumed market prices for the electricity required for compression of air.

For this study, the plant configuration was assumed to include a 100 MW generator with 12 hours of operation, 67 MW of compressor power (with re-pressure time of 12 hours), and storage volume of 1,200 MWh.

It was assumed that pipeline gas would be available at adequate pressure (30 bar (g)) to support plant operation at rated load under all ambient conditions without on-site gas booster compressors. The charging electricity ratio (CER) is the ratio of generator output in kWh to compressor motor input in kWh. For the above plant, the CER is 1.5. Typical CERs range from 1.2 to 1.8.

This technology can be considered commercial, yet immature, as there are only a few CAES plants in operation. The following plants are in operation:

- E.N. Kraftwerke's 290 MW CAES Plant in Huntorf, Germany – went online in 1978; and
- Alabama Electric Cooperative's 110 MW CAES Plant in McIntosh, Alabama, U.S. – went online in 1991.

As of February 2009, the EPRI announced a program to develop advanced CAES plants and is seeking utilities to participate in two demonstration projects. One will use below ground air storage for bulk storage (at about 300 MW with 10-hour storage). The other will use an above-ground air vessel/piping system for short-term storage (at about 15 MW with 2-hour storage).

The overnight capital cost of a CAES plant within the 100 to 300 MW range has been estimated at between US$1,100 and US$1,500 per kW, excluding the cost of the underground storage reservoir, switchyard, transmission and owner's cost. Using an exchange rate of 0.75 US$/CDN$ this translates to between CDN$1,300 and CDN$1,770 per kW. As noted, this cost does not include the costs required for preparing and upgrading the underground air storage reservoir. Costs for this will be site specific but could range from CDN$18 to CDN$62 per kWh of storage capacity. Based on the assumed configuration requiring 1,200 MWh of storage this translates to a specific cost for storage of between CDN$210 and CDN$740 per kW. The total overnight cost is thus estimated to range between CDN$1,510 and CDN$2,510 per kW (2016$) for plants in the 100 to 300 MW range. Due to economies of scale the higher cost would typically be associated with the smaller plants so the total overnight cost for a 100 MW CAES plant is estimated at $1,850 per kW which includes the storage cost..

A CAES plant would be most economic when sited on an abandoned mine site. Based on limited research, there are a significant number of abandoned mine sites in southern New Brunswick between Saint John and Moncton [NB DNR Report][29]. Salt caverns are particularly attractive as storage reservoirs, and there may be some potential in the Sussex area where Potash Corporation of Saskatchewan has active potash and salt mining operations.

The operational costs for this alternative include costs for operators of the facility, maintenance, labour and materials and the administrative costs to provide the facility service. Non-fuel operating and maintenance costs were based on the simple-cycle combustion turbine peaking plant numbers as given in Section 1.3 (Combustion Turbines).

The project lead time was estimated based on simple cycle peaking plant, and factored to allow for the longer lead times for the compressor/generator equipment as it is a highly customized design. The project lead time would be approximately 30 months, assuming that the geological formation had been previously located and investigated during the feasibility study phase (not included in the lead time). This CEAS plant would have an accounting life of 25 years.

[29] NB Department of Natural Resources – Abandoned Mine Sites Policy – Policy MRE 006 2004.

3 EXISTING SUPPLY, LIFE EXTENSION AND CONVERSION

3.1 Millbank and Ste. Rose Life Extension

This generation option is for upgrades to the existing Millbank and Ste. Rose Generating Station (pictured below) in the form of a retrofit of combustion turbines and a life extension program for an additional 25 years.

Figure 37: The Ste. Rose Generating Station

The total project cost of this retrofit was estimated at $226 per kW. This is an estimate from plant engineering staff and is based on normal running hours expected over the next 13 years of its current lifecycle.

Appendix 5: Project and Operating Cost Parameters

Table 1: Public Funding Scenario (Base Case)

							Levelized Cost of Electricity - LCOE ($/MWh)						
								Operating Costs					
Project	Capacity (MW)	Capacity Factor (%)	In-Service Capital Cost (2013 $k)	In-Service Capital Cost ($/KW)	Expected Life (Years)	Representative Heat Rate (Btu/KWh)	Capital	Fuel	Variable O&M	Fixed O&M	Total Operating (before income taxes)	Income Taxes	Total LCOE
Simple Cycle Gas Turbine - High Efficiency	100	5.0%	158,474	1,586	25	9,639	280.63	129.02	4.95	37.68	171.65	0.00	452.29
Simple Cycle Gas Turbine - Mid Efficiency	93	5.0%	109,567	1,173	25	11,449	207.53	153.26	18.48	34.09	205.83	0.00	413.36
Large Combined Cycle - Gas	422	80.0%	749,124	1,775	25	6,615	19.63	88.55	3.64	2.36	94.55	0.00	114.17
Small Combined Cycle - Gas	289	80.0%	534,052	1,850	25	6,755	20.46	90.42	4.11	3.13	97.66	0.00	118.12
LM6000PF Combined Cycle	122	80.0%	264,961	2,179	25	7,241	24.09	96.93	4.43	3.40	104.75	0.00	128.84
LM6000PF Combined Cycle - Cooling Tower	121	80.0%	265,795	2,189	25	7,285	24.21	97.51	4.43	3.40	105.34	0.00	129.54
Microturbines	1	80.0%	4,392	4,723	25	6,100	52.22	151.98	28.25	10.08	155.95	0.00	208.17
Natural Gas Fuel Cells	1	80.0%	14,107	10,077	20	7,980	124.33	191.46	0.00	58.46	243.67	0.00	367.99
Biomass Combined Heat and Power	14	80.0%	88,573	6,327	25	8,680	69.95	46.55	4.95	10.08	61.57	0.00	131.52
Biomass Bubbling Fluidized Bed	50	80.0%	267,646	5,353	35	13,500	52.07	77.04	7.60	21.69	106.33	0.00	158.40
Municipal Solid Waste	50	80.0%	535,293	10,706	35	18,000	104.14	0.00	12.09	81.81	93.90	0.00	198.04
Geothermal	30	80.0%	228,940	7,631	30	0	78.27	0.00	18.68	20.43	39.11	0.00	117.37
Compressed Air Energy Storage	100	16.8%	194,226	1,942	25	0	102.57	0.00	68.72	9.56	78.28	0.00	180.85
Nuclear	1,100	80.0%	9,270,151	8,427	30	11,000	86.43	7.86	5.60	31.09	44.55	0.00	130.98
Nuclear - Small Modular	50	80.0%	561,827	11,237	30	11,000	115.24	7.86	5.60	35.53	48.99	0.00	164.23
Small Wind	10	40.0%	25,015	2,502	20	0	61.74	0.00	11.70	26.72	38.43	0.00	100.16
Large Wind	50	40.0%	115,643	2,313	20	0	57.08	0.00	11.70	26.72	38.43	0.00	95.51
Small Solar Photovoltaic - Fixed Tilt Racking	10	16.0%	23,410	2,341	30	0	120.04	0.00	12.45	23.98	36.43	0.00	156.48
Large Solar Photovoltaic - Fixed Tilt Racking	25	16.0%	57,488	2,300	30	0	117.92	0.00	12.45	23.98	36.43	0.00	154.35
Large Solar Photovoltaic - Single Axis Tracking	25	18.5%	61,373	2,455	30	0	108.87	0.00	12.45	20.74	33.19	0.00	142.07
Pumped Storage Hydro	100	41.4%	690,365	6,904	50	0	119.21	0.00	8.76	10.60	19.35	0.00	138.57
Small Hydro	20	35.0%	107,655	5,383	50	0	109.83	0.00	0.00	20.82	20.82	0.00	130.65
Wave Power	10	25.0%	102,593	10,259	20	0	405.12	0.00	11.70	128.27	139.97	0.00	545.09
Tidal Stream Power	50	35.0%	404,924	8,098	20	0	228.42	0.00	0.00	101.16	101.16	0.00	329.59
Hydro - Grand Falls	100	36.4%	491,053	4,911	50	0	96.46	0.00	0.00	6.03	6.03	0.00	102.48
Hydro - High Narrows	40	46.2%	301,446	7,536	50	0	116.49	0.00	0.00	2.24	2.24	0.00	118.73
Interconnection Purchases	350	50.0%	0	0	25	10,000	0.00	61.31	0.00	20.75	82.07	0.00	82.07
Millbank/Ste Rose Life Extension	500	5.0%	112,893	226	25	12,000	39.94	270.80	0.00	0.00	270.80	0.00	310.75

Appendix 6: Sensitivity Analysis Expansion Plans

Capital and Escalation Sensitivity Expansion Plans

FY Ending	Integrated Plan	All Capital +25%	All Capital -25%	Private Financing (WACC = 7.13%)	Low Wind Escalation
2018	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)
2019					
2020	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)
2021	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)
…					
2031	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (3 x 99 MW) Wind (200 MW)	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (2 x 99 MW) PUR (175 MW)
2032					
2033	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement
…					
2040	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)
2041	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (2 x 412 MW) CT (3 X 93 MW) Millbank (2 x 99 MW)	NGCC (2 x 412 MW) CT (93 MW) Millbank (2 x 99 MW) Grand Falls (100 MW)	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (2 x 412 MW) Millbank (3 x 99 MW) Wind (600 MW)
2042			CT (93 MW)		
PVRR ($2017)	**$ 24.6 B**	**$ 24.9 B**	**$ 24.3 B**	**$ 24.7 B**	**$ 24.6 B**

Fuel & Purchased Power and Foreign Exchange Sensitivity Expansion Plans

FY Ending	Integrated Plan	Gas and Market prices +25%	Gas and Market prices -25%	FOREX +15% (USD/CAD)	FOREX -15% (USD/CAD)
2018	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)
2019					
2020	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)
2021	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)
…					
2031	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (4 x 99 MW) Wind (200 MW)	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (3 x 99 MW) Wind (200 MW)	Millbank / Ste Rose (3 x 99 MW)
2032					
2033	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement
…					
2040	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)
2041	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (2 x 412 MW) CT (93 MW) Millbank (1 x 99 MW) Grand Falls (100 MW)	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (2 x 412 MW) CT (93 MW) Millbank (2 x 99 MW) Grand Falls (100 MW)	NGCC (2 x 412 MW) CT (3 x 93 MW) Millbank (2 x 99 MW)
2042		CT (93 MW)		CT (93 MW)	
PVRR ($2017)	**$ 24.6 B**	**$ 24.8 B**	**$ 24.3 B**	**$ 25.3 B**	**$ 23.9 B**

Load Related Sensitivity Expansion Plans

FY Ending	Integrated Plan	High Load Forecast	Low Load Forecast	High Energy Efficiency	Extreme Energy Efficiency
2018	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (820 MW)	Energy Smart NB (1,084 MW)
2019					
2020	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)
2021	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)
…					
2031	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (5 x 99 MW)	Millbank / Ste Rose (2 x 99 MW)	Millbank / Ste Rose (2 x 99 MW)	Millbank / Ste Rose (2 x 99 MW)
2032					
2033	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement
…					
2040	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)
2041	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (3 x 412 MW) CT (2 x 93 MW)	NGCC (2 x 412 MW) Millbank (3 x 99 MW)	NGCC (2 x 412 MW) Millbank (3 x 99 MW)	NGCC (2 x 412 MW)
2042					
PVRR ($2017)	**$ 24.6 B**	**$ 26.4 B**	**$ 23.2 B**	**$ 24.4 B**	**$ 24.7 B**

Solar PV Related Sensitivity Expansion Plans

FY Ending	Integrated Plan	Medium Solar Penetration	High Solar Penetration
2018	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)
2019			
2020	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)
2021	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)
…			
2031	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (3 x 99 MW)
2032			
2033	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement
…			
2040	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)
2041	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (2 x 412 MW) CT (2 x 93 MW) Millbank (2 x 99 MW) WIND (200 MW)	NGCC (2 x 412 MW) CT (2 x 93 MW) Millbank (2 x 99 MW)
2042			
PVRR ($2017)	**$ 24.6 B**	**$ 24.5 B**	**$ 24.4 B**

GHG Related Sensitivity Expansion Plans

FY Ending	Integrated Plan	CO2 Cap: 3 Mt	CO2 Cap: 2.5 Mt	Federal GHG Regulation
2018	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)
2019				
2020	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)
2021	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)	LORESS (80 MW)
2022				
2023			Grand Falls (100 MW)	
…				
2031	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (2 x 99 MW) Wind (200 MW)	Grand Falls (100 MW) CT (93 MW) Millbank / Ste Rose (5 x 99 MW) Wind (200 MW)
2032				
2033	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement
…				
2040	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)
2041	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (2 x 412 MW) CT (93 MW) Millbank (3 x 99 MW)	NGCC (2 x 412 MW)
2042			CT (93 MW)	CT (93 MW)
PVRR ($2017)	**$ 24.6 B**	**$ 25.1 B**	**$ 25.4 B**	**$ 27.1 B**

Expansion Plans for Scenarios

FY Ending	Integrated Plan	High Electrification	Global Recession
2018	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)	Energy Smart NB (621 MW)
2019			
2020	Embedded Generation (13 MW)	Embedded Generation (13 MW)	Embedded Generation (13 MW)
2021	LORESS (80 MW)	LORESS (80 MW) Wind (200 MW)	LORESS (80 MW)
2022			
2023		Grand Falls (100 MW)	
…			
2031	Millbank / Ste Rose (3 x 99 MW)	Millbank / Ste Rose (4 x 99 MW) Wind (200 MW)	Millbank / Ste Rose (2 x 99 MW)
2032			
2033	Mactaquac Life Achievement	Mactaquac Life Achievement	Mactaquac Life Achievement
…			
2040	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)	Lepreau Replace-in-kind (660 MW)
2041	NGCC (3 x 412 MW) Millbank (2 x 99 MW)	NGCC (3 x 412 MW) Millbank (99 MW)	NGCC (2 x 412 MW) Millbank (3 x 99 MW)
2042			
PVRR ($2017)	**$ 24.6 B**	**$ 27.1 B**	**$ 22.8 B**

Appendix 7: Glossary and Abbreviations

Biomass: Non-fossilized organic matter often used as fuel (e.g., wood waste).
British thermal unit (BTU): The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, equalling roughly 1000 kilowatts (kW).
Capacity: The maximum power that a generating unit, generating station or other electrical apparatus can supply, usually expressed in megawatts.
Carbon Dioxide (CO_2): A colourless, odourless, non-poisonous gas that is a normal part of the ambient air. Carbon dioxide is also a product of fossil fuel combustion. It is a greenhouse gas that traps terrestrial (i.e., infrared) radiation and contributes to the potential for global warming.
Cogeneration: The simultaneous production of electrical or mechanical energy and useful heat energy from a single fuel source. For example, forest sector mills can burn wood waste in a boiler to generate electricity and use low-temperature steam from the generator in pulping processes.
Decommission: To take a piece of equipment such as a generation or transmission facility permanently out of service.
Demand: The size of any load, expressed in kilowatts (kW), averaged for a specified period of time.
Demand-Side Management: Actions that modify customer demand for electricity, helping defer the need for new energy and capacity supply additions.
Distributed Generation: Also referred to as DG, is a method of generating electricity from multiple small energy sources very near to where the electricity is actually used.
Distribution System: The poles, conductors and transformers that deliver electricity to customers. The distribution system transforms high voltages to lower, more usable levels. Electricity is distributed at 120/240 volts (V) for most residential customers and 120 to 600 V for the majority of commercial customers.
Economical Dispatch of Generating Units: The scheduling of power production as demand for electricity varies, according to the lowest cost generating sources available to the System Operator, given transmission limits and other constraints.
Electrical Energy: Electrical utilities sell electrical energy to their customers who, in turn, convert this energy into a desirable form — such as work, heat, light, or sound. Electrical energy is measured in kilowatt hours (kWh).
Energy: Quantity of actual power produced by a generating station over a period of time, measured in megawatt-hours (MWh).
Energy & Utilities Board (EUB): The provincial government's regulatory body through which all of New Brunswick's electricity and natural gas rate applications must be approved before rate increases can become implemented.
Energy Imbalance Service: The hourly difference between the actual and scheduled energy flow.
Federal Energy Regulatory Commission (FERC): A US agency that regulates the interstate transmission of natural gas, oil and electricity.

Fly Ash: Represents the finely divided particles of ash suspended in gases resulting from the combustion of fuel. Electrostatic precipitators are used to remove fly ash from the gases prior to the release from a power plant's stack.
Generator: A machine that converts mechanical energy — such as a rotating turbine driven by water, steam, or wind — into electrical energy.
Gigajoule (GJ): A measure of energy for natural gas equaling one billion joules or one million BTUs. One gigajoule of energy is equivalent to that provided by approximately 278 kilowatt hours of electricity or 30 litres of gasoline.
Gigawatt (GW): The unit of electrical power equivalent to one billion watts or one million kW.
Greenhouse Gas (GHG): Gases that trap heat in the atmosphere and are thought to contribute to global climate change, or the "greenhouse effect," including carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O) and sulphur hexafluoride (SF6).
Hydroelectricity: Electricity produced by harnessing the power of falling water or streamflow.
Independent Power Producer (IPP): Operator of a privately owned electricity generating facility that produces electricity for sale to utilities or other customers.
Integrated System: An interconnected network of transmission lines, distribution lines and substations linking generation stations to one another and to customers throughout a utility's service area, but excluding isolated customers who are connected to freestanding generating plants.
Joule (J): A measure of energy for natural gas.
Kilowatt (kW): One thousand watts; the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light 10 100-watt light bulbs.
Kilowatt Hour (kWh): The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.
Load: The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy consuming equipment of the consumer.
Load Forecasting: Determining an estimate of load requirements for some future time.
Megawatt (MW): Unit of electrical power to measure the generating capability of a generating station or the maximum demand of an electricity consumer
National Energy Board (NEB): A Canadian federal regulatory agency.
Natural gas: A fossil fuel made from hydrocarbons stored millions of years ago when plants and other materials were buried in the earth's crust. Composed mostly of methane — a colourless and non-toxic substance — natural gas creates virtually no unburned particles or smoke to pollute the atmosphere. The products of combustion are chiefly carbon dioxide and water.
Net Capacity Factor: The actual station generation of power to the grid in MW divided by the ideal maximum generation of power to the grid in MW possible.
Net Metering: A program that allows customers with their own generation facility to "bank" their surplus electricity with the electric utility. This banked surplus is then applied against the amount of electricity supplied by the utility.
Nitrogen Oxides (NO_X): Gases consisting of one atom of nitrogen and varying numbers of oxygen atoms. Nitrogen oxides are produced, for example, by the combustion of fossil fuels in vehicles and electric power plants. In the atmosphere, nitrogen oxides can contribute to formation of photochemical ozone (smog) and impair visibility.

North American Electric Reliability Corporation (NERC): A US agency that establishes and enforces reliability standards for the bulk power system.
Open Access Transmission Tariff: Establishes non-discriminatory access to the transmission system for generators and customers inside and outside the province and generates revenues for Transco to operate and maintain the transmission system, based on the cost of providing services.
Outage: A planned or unplanned interruption of one or more elements of an integrated system.
Peak Capacity: The maximum amount of electrical power that generating stations can produce in any instant.
Peak Demand: The maximum instantaneous demand on a power system. Normally the maximum hourly demand.
Point-to-point Tariff: The fees charged for point-to-point service from one specific point to another. Typically this service is used for transporting energy through or out of the province.
Power grid: A number of interconnecting electrical power systems linking together electrical utilities and covering a large geographical area.
Power Purchase Agreements: Supply contracts between two parties for the supply of electricity.
Price Elasticity: A measure used in economics to show the responsiveness or elasticity of the quantity demanded of a good or service to a change in its price.
Renewable Portfolio Standard: Requirement that a certain amount of electricity sold in a competitive market includes some prescribed standard amount produced from renewable sources
Standard Service Supplier: The provider responsible for supplying adequate capacity and energy to meet customer demand for those customers not served by a competitive supplier.
Sulphur Dioxide (SO_2): Belongs to a family of sulphur oxide gases (SO_X) and is a colourless gas. It is formed from the sulphur contained in raw materials such as coal, oil and metal-containing ores used during combustion and refining processes. Flue gas desulphurization units are used to remove SO2 from the gases prior to the release from a power plant's stack.
System Average Interruption Duration Index (SAIDI): The average total duration of interruptions during the year.
System Average Interruption Frequency Index (SAIFI): The average number of times each customer on the distribution system is without power annually.
System Operator: An independent, not-for-profit entity that directs the operation of the electricity market maintains the long-term adequacy and reliability of the electricity system and administers the Open Access Transmission Tariff.
Transmission system: The towers, conductors, substations and related equipment involved with transporting electricity from generation source to areas for distribution — or to the power systems of out-of-province electrical utilities.

Abbreviations

AAR: Alkali-Aggregation Reaction
BTU: British Thermal Unit
CAD: Canadian dollar
CAPP: Canadian Association of Petroleum Producers
CFL: Compact fluorescent light
cfs: cubic feet per second
CH4: Methane (natural gas)
CMP: Central Maine Power
CO: Carbon monoxide
CO_2: Carbon dioxide
CPI: Consumer Price Index
CT: Combustion turbine generating unit
EIA: Energy Information Administration
EPA: Environmental Protection Agency
EUB: Energy & Utilities Board
ERCOT: Electric Reliability Council of Texas
ETS: European Trading Scheme
FERC: Federal Energy Regulatory Commission
FRCC: Florida Reliability Coordinating Council
GHG: Greenhouse Gas
GJ: Gigajoule
GW: Gigawatt
GWh: Gigawatt hour
ha: hectares
HQ: Hydro Quebec
HVDC: High Voltage Direct Current
IBEW: International Brotherhood of Electrical Workers
IRP: Integrated Resource Plan
J: Joule
kt: Kilotonne
kV: Kilovolt
kW: Kilowatt
kWh: Kilowatt hour
LCOE: Levelized Cost of Electricity
LED: Light emitting diode
MECL: Maritime Electric Company Limited
Mt: Megatonne
MW: Megawatt
MWh: Megawatt hour
MRO: Midwest Reliability Organization
N_2: Nitrogen gas
N_2O: Nitrous oxide
NEB: National Energy Board

NERC: North American Electric Reliability Corporation
NGCC: Natural Gas Combined cycle generating unit
NO_X: Nitrogen oxides
NPCC: Northeast Power Coordinating Council
NPV: Net present value
O&M: Operating and Maintenance
OPEC: Organization of Petroleum Exporting Countries
PCCI: Power Capital Cost Index
PEI: Prince Edward Island
PPA: Power purchase agreement
PSNH: Public Service of New Hampshire
PVRR: Present value of revenue requirement
PUR: Firm Capacity Purchase
REEP: Residential Energy Efficiency Program
RFC: ReliabilityFirst Corporation
ROE: Return on Equity
RPS: Renewable Portfolio Standard
SAIDI: System Average Interruption Duration Index
SAIFI: System Average Interruption Frequency Index
SARA: Species at Risk Act
SERC: SERC Reliability Council
SO_2: sulphur dioxide
SO_X: sulphur oxide gases
SPP: Southwest Power Pool
TPM: Total Particulate Matter
TRE: Texas Reliability Entity
TW: Terawatt
TWh: Terawatt hour
TTC: Total Transfer Capability
USD: US dollar
WACC: Weighted Average Cost of Capital
WCI: Western Climate Initiative
WECC: Western Electricity Coordinating Council