## NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF the New Brunswick Power Corporation and Section 103(1) of the Electricity Act, SNB 2013 c.7

# 2023/24 GENERAL RATE APPLICATION

## EVIDENCE

**REVISED NOVEMBER 7, 2022**

New Brunswick Power Corporation

# NEW BRUNSWICK ENERGY AND UTILITIES BOARD

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# 1.0 INTRODUCTION

NB Power takes very seriously its obligation to supply safe, reliable, competitively priced electricity to New Brunswick homes and businesses. We have an unwavering commitment to our customers, to the safety of the public and our employees, and to maintaining the reliability of electric service in New Brunswick.

NB Power maintains a high degree of fiscal responsibility and accountability while ensuring that we continue to meet the needs of our customers. Technology advancements, changing customer preferences, and climate change present new challenges for NB Power to manage, as well as potential positive opportunities to seize, both for the company and our customers.

## 1.1 Business Environment and Challenges

As New Brunswick's utility, we must evolve to meet the future needs of New Brunswickers in a responsible, safe, reliable, and cost-effective way. Aging infrastructure, increased carbon pricing, expanding electrification of the way we live and work, and the aggressive transition to renewable and low carbon generating sources present significant fiscal challenges that will put rising pressure on rates.

In the current and upcoming fiscal years, NB Power is facing unprecedented challenges due to never-before-seen increases in fuel and purchased power costs and volatility, higher than anticipated interest rates, significant increases in commodity prices, supply chain uncertainty, and extraordinary inflationary pressures. Many New Brunswickers and people across the world are facing the very same cost challenges. To help deal with these rising expenses, NB Power is committed to reducing costs and has engaged PwC Canada ("PwC") to identify all possible opportunities without compromising on reliability, safety, or affordability.

## 1.2 Basis for Increase in Rates

In each of NB Power's General Rate Applications since the 2015/16 fiscal year, the Corporation's requested rate increases have been based on a balancing of the policy considerations set out in Section 68 of the *Electricity Act*; proposed rates are intended to allow for sufficient income to achieve a capital structure of 20 per cent equity (s. 68(a)(ii)) over time, while maintaining rates as low as possible, and reducing variability in rate changes from year to year (s. 68(c)).

### 1.2.1 Underlying Cost Increases

The world economy is facing exceptional increases in market prices for all fuels and for purchased power when compared to historical norms, and a macroeconomic environment which simultaneously consists of the most significant inflationary cycle in over 40 years, together with significant increases in interest rates. As is the case with any business or household that must purchase fuel and other commodities, NB Power is not immune to the impacts of these rising costs. The most significant impacts are described below.

### 1.2.2 Fuel and Purchased Power

Table 1.2.1 provides a listing of market futures for the relevant fuel and market price indexes used in the preparation of NB Power's 2023/24 budget, as compared to the actual commodity price averages for the five-year period ending in March 2022. This comparison demonstrates that pricing for the input components of NB Power's Fuel and Purchased Power expense have increased between 58 per cent and 158 per cent over historical norms.

These market price increases, together with increases in forecasted in-province sales volumes, have resulted in an increase in fuel and purchased power expense related to the supply of in-province customers by $102.8 million (excluding interruptible sales). Further detail on this cost increase appears in Section 3.1.a.

**Table 1.2.1**

**NB Power Corporation**
**Commodity Price Comparison**

| Commodity | Index | Season | Unit | (1) Historical 5-Year Average | (2) 2023/24B Average | (3) Increase (%) |
|---|---|---|---|---|---|---|
| (1) Electricity | ISO-NE Mass Hub | Summer (Apr-Nov) | $US/MWh | $29.44 | $58.24 | 98% |
| (2) Electricity | ISO-NE Mass Hub | Winter (Dec - Mar) | $US/MWh | $53.95 | $121.87 | 126% |
| (3) Natural Gas | Algonquin | Summer (Apr-Nov) | $US/MMBtu | $2.73 | $5.75 | 110% |
| (4) Natural Gas | Algonquin | Winter (Dec - Mar) | $US/MMBtu | $6.52 | $16.82 | 158% |
| (5) Natural Gas | AECO | Summer (Apr-Nov) | $US/MMBtu | $1.72 | $4.40 | 156% |
| (6) Natural Gas | AECO | Winter (Dec - Mar) | $US/MMBtu | $2.17 | $4.78 | 120% |
| (7) Heavy Fuel Oil | Brent | Annual | $US/bbl | $61.25 | $96.48 | 58% |
| (8) Coal | API #2 | Annual | $US/Ton | $79.83 | $196.44 | 146% |

### 1.2.3 Financing Charges

In response to high inflation, the Bank of Canada has been tightening monetary policy and has implemented significant interest rate increases thus far in 2022. Given the outlook for inflation, it is expected that interest rates will rise further. Short term debt interest rates are projected to be 3.1 per cent in 2023/24 as compared to 0.4 per cent assumed for 2022/23, an increase of 2.7 per cent. Higher interest rates will increase finance costs by approximately $31 million in the test year.

### 1.2.4 Inflationary Pressures and Other Commodity Price Increases

Both general inflationary pressures and increases in specific commodity prices have contributed to an increase in costs. Within hired services, contractors who operate motor vehicles in the delivery of services have sought to pass along increases in fuel prices, forcing the utility to revise a number of contracts to incorporate these additional costs. Price increases for specific commodities such as steel, copper, aluminum, and lumber have impacted NB Power’s entire supply chain, with resulting increases in forecasted capital expenditures and Operations, Maintenance & Administration (“OM&A”) expenses.

As outlined in greater detail in Section 3.2, NB Power is exposed to increasing OM&A costs, despite considerable effort to reduce such costs in the test year. While not exhaustive, the most significant drivers of increased OM&A in the test year are:

- Increased spending on energy efficiency measures required to meet pending changes under the *Electricity Act* regulations setting energy reduction targets ($13.6 million)
- A one-time reclassification of costs related to the Mactaquac Life Achievement Project ($8.8 million)
- Increases in digital technology costs, including inflationary impacts on software licensing fees and computer equipment leasing costs, as well as increased reliance on digital technology (e.g., platforms to enable remote work, Microsoft suite of products, etc.) ($8.1 million)
- Increase in resources allocated to operations and maintenance activities as opposed to capital outage work at the Point Lepreau Nuclear Generating Station ("PLNGS") as a result of normal fluctuations in the scope and length of outages from one year to the next ($5.2 million)
- Increases in labour and benefits arising from wage increases that are well below the rate of inflation ($10.7 million)

#### 1.2.5 NB Power Efforts to Control Costs

NB Power recognizes that the requested rate increase is well above the level of rate increases in recent history and is committed to reducing costs across the organization in order to keep increases to the minimum necessary.

As part of the 2023/24 budget process, NB Power eliminated or deferred $18.5 million of initially proposed spending in order to reduce the rate ask. These savings are embedded in the revenue requirements detailed in the balance of NB Power's evidence.

The 2023/24 revenue requirements also include $27.5 million in improvement credits in recognition of NB Power's ongoing continuous improvement initiative and a cost optimization exercise being undertaken by PwC to identify opportunities for short-, medium-, and long-term cost savings. This exercise is ongoing at the time of filing this Application and the results are not yet available. In anticipation of the savings that will be realized through this initiative, a credit has been added to the Hired Services line item in Operations, Maintenance & Administration ("OM&A") expense.

In total, NB Power plans to achieve $46 million in cost reductions in the 2023/24 fiscal year. This is the most significant cost reduction commitment NB Power has ever made.

### 1.3 Rate Increase Request

In the context of the largely unanticipated and uncontrollable cost pressures discussed above, NB Power is seeking a rate increase of 8.9 per cent across all customer classes for 2023/24.

The proposed rate increase of 8.9 per cent does not make material progress toward the 20 per cent equity target established in s. 68(a)(ii) of the *Electricity Act*. Due to the extraordinary increases in costs, the rate increase requested is necessary just to ensure that forecasted costs for the 2023/24 fiscal year are recovered. Even with such a significant increase, NB Power's net income is forecasted to be only $13.9 million and net debt is forecasted to increase by $39.6 million.

NB Power acknowledges that this increase is larger than what our customers have come to expect; however, as discussed in more detail above and throughout this Application, this rate increase is necessary for NB Power to carry on its required operations and maintenance activities, to service its debt obligations, and to fund required capital expenditures to maintain the safety and reliability of our infrastructure.

Table 1.3.1 below sets out NB Power's annual average rate increases over the twelve-year period from 2011 to 2022. NB Power's average annual rate increase over that period was 1.35 per cent, a rate significantly lower than the average annual rate of inflation.

**Table 1.3.1**

**NB Power Corporation**
**Historical Rate Increases & NB CPI**

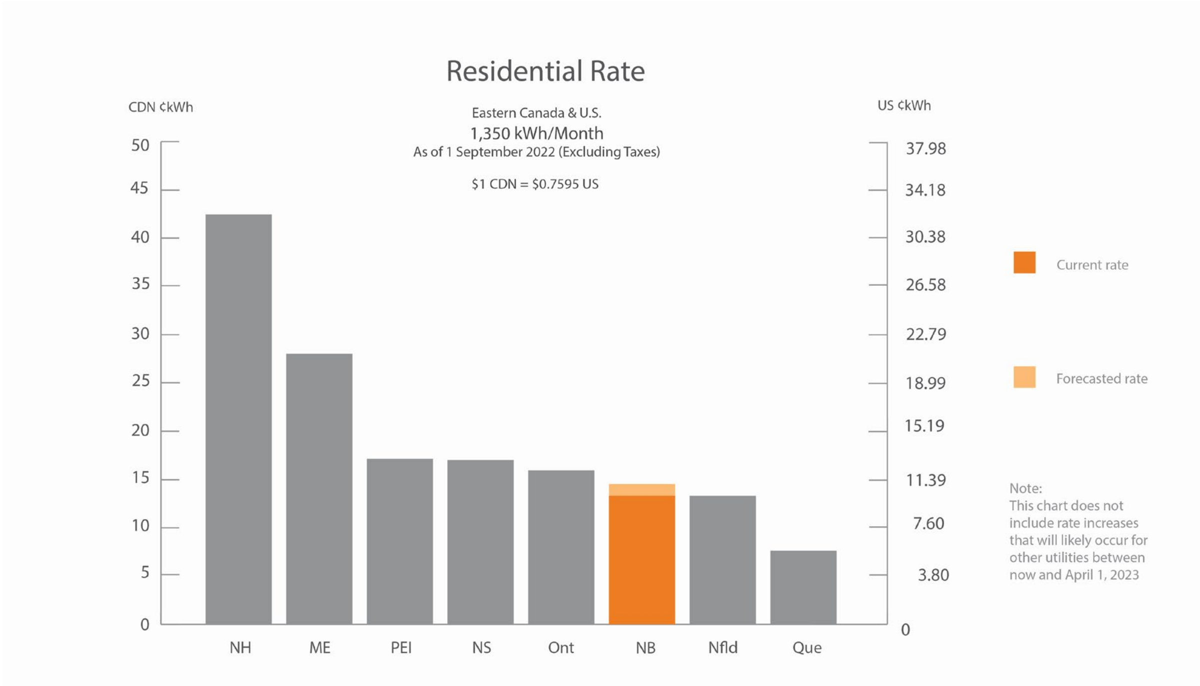
| | (1) Year | (2) Rate Increases | (3) NB CPI |
|---|---|---|---|
| (1) | 2011 | 0.00% | 3.54% |
| (2) | 2012 | 0.00% | 1.67% |
| (3) | 2013 | 2.00% | 0.82% |
| (4) | 2014 | 2.00% | 1.46% |
| (5) | 2015 | 1.63% | 0.48% |
| (6) | 2016 | 1.66% | 2.23% |
| (7) | 2017 | 1.77% | 2.34% |
| (8) | 2018 | 0.88% | 2.13% |
| (9) | 2019 | 2.48% | 1.72% |
| (10) | 2020 | 1.82% | 0.22% |
| (11) | 2021 | 0.00% | 3.81% |
| (12) | 2022 | 2.00% | 7.44% |
| (13) | Average | 1.35% | 2.32% |
| (14) | Cumulative | 16.24% | 27.86% |

Note: New Brunswick CPI for 2022 is the average of the monthly values to August 2022.

For more than a decade, NB Power has made significant efforts to maintain low and stable rates, with the result that electricity rates in New Brunswick compare favourably with other jurisdictions in Canada and the United States, even factoring in the requested increase for the 2023/24 fiscal year. Table 1.3.2 below compares NB Power's rates for an average residential customer to utilities in eastern Canada and the United States.

**Table 1.3.2**

**NB Power Corporation**
**Comparison of Residential Rates**




Even though electricity rates in New Brunswick continue to be amongst the lowest in the region, NB Power recognizes that low-income customers are disproportionately impacted when rates increase. Accordingly, NB Power will continue to work with these customers through the Enhanced Energy Savings Program ("EESP") to assist them in managing their energy bills. NB Power estimates that the rate increase proposed will increase the average customer's electricity bill by $200 per year, while the average participant in the EESP achieves approximately $500 per year in bill savings.

In addition, NB Power will continue to support all residential and business customers in offering valuable energy efficiency programs. In keeping with a new regulation under the *Electricity Act* proposed by the Province of New Brunswick, new mandatory targets for energy reduction will be established. NB Power will spend an additional $13.6 million in 2023/24 to meet these new targets, of which $11.6 million consists of incentives payable to participating customers.

### 1.4 Supporting New Brunswickers

NB Power understands how difficult the past two years have been on our customers and the extraordinary circumstances everyone is now facing with rising costs. From the beginning of the COVID-19 pandemic in early 2020, NB Power has assisted our customers in a number of ways and we will continue to work with customers to help them manage their energy costs.

While we have worked hard to manage the rate increase requested in this Application, we know how difficult this will be for our customers. We are New Brunswick's utility and our focus every day is on providing our customers safe, reliable, and competitively priced electricity.

# 2.0 GENERAL MATTERS

## 2.1 Revenue Requirement and Rate Increase Request[1]

As required by s. 103(1) of the *Electricity Act,* S.N.B. 2013, c.7 (the "*Act"),* NB Power files its application for approval by the New Brunswick Energy and Utilities Board of the Corporation's schedule of rates for the 2023/24 fiscal year.

In this 2023/24 General Rate Application ("GRA"), NB Power is seeking Board approval of the rates as set out in Appendix AC i., NB Power's Proposed Rate Schedules (Sections N and O), based on a revenue requirement totaling $2,314.6 million. This revenue requirement represents a rate increase of 8.9 per cent and includes net earnings of $13.9 million.

NB Power requests that the Board approve a uniform 8.9 per cent increase in rates across all customer classes for 2023/24. NB Power acknowledges that this increase is larger than what our customers have come to expect; however, as discussed generally in Section 1 and in more detail in the sections that follow, this rate increase is necessary for NB Power to carry on its required operations and maintenance activities, to service its debt obligations, and to fund required capital expenditures, all in the context of never-before-seen input prices and volatility for fuel and purchased power and other significant cost pressures resulting from higher than anticipated interest rates, commodity prices, and general inflation.

The regulatory framework requires the Board to base its rate decision on the revenue requirements of NB Power, taking into consideration the policy set out in s. 68 of the *Act,* any directives issued by the Executive Council under s. 69 of the *Act*, the most recent Integrated Resource Plan (IRP) (Appendix BE i.), the Three-year plan 2024 to 2026 (Appendix AB.), and any other relevant requirements imposed by law.

In accordance with the *Act*, this Application includes:

[1] This section addresses Minimum Filing Requirements 14, 16, 17, 18 and 22.

a. the schedules of rates NB Power proposes to charge commencing on April 1, 2023
b. NB Power's revenue requirement for the fiscal year 2023/24
c. NB Power's projection of load and revenue for the fiscal year 2023/24

### 2.2 One-year Rate Application

Changes introduced to the *Electricity Act* in 2021 permit NB Power to request Board approval of up to three years of rates with each general rate application.

Due to the current higher than normal levels of volatility and uncertainty with respect to fuel and purchased power costs, supply chain issues, capital and equipment costs, interest rates, labour costs, and general inflationary pressures, it is more difficult than normal to forecast with any reasonable certainty beyond the immediate future. While there is significant potential that fuel and purchased power prices will remain elevated for some time, this is also accompanied by abnormal volatility. Volatility of a given percentage has a much more pronounced impact at high prices.

In NB Power's view, it would be unfair of the utility to request the Board to set rates for fiscal years 2024/25 and 2025/26 based on forecasts made in the current extraordinary economic conditions. Setting rates for the upcoming fiscal year, and applying for new rates next year based on market conditions at that time, is in the best interest of our customers. Though unpredictable at present, it is possible that some of the underlying drivers of these abnormal financial conditions could resolve somewhat or at least become more predictable over the coming year. In any event, forecasting should be more reliable for 2024/25 and 2025/26 than it is currently, as it will be closer in time.

In addition, NB Power has engaged an external organization to conduct a cost optimization exercise, as well as to lead the utility in the development of a comprehensive strategic plan for the future. These exercises are ongoing at the time of filing this Application and it is NB Power's expectation that some of the cost saving opportunities to be identified will not be realized until after the 2023/24 test year. Applying for more than one year's rates at this time would mean any cost saving opportunities resulting from this exercise would not be reflected in the approved rates for 2024/25 and 2025/26.

Finally, NB Power anticipates a decision will be rendered on the Mactaquac Life Achievement Project ("MLAP") in the coming year. Whether this project proceeds or not will have a significant impact on the future direction of the company, and revenue requirements for 2024/25 and 2025/26 should reflect the decision that will be made by the The Lieutenant-Governor in Council.

Given the extraordinary circumstances discussed above and elsewhere in this Application, it is NB Power's view that the additional regulatory process costs related to filing a general rate application after only one year rather than the three years permitted under the legislation are more than justified, as we look to achieve additional benefits and savings for our customers.

### 2.3 Other Approvals Requested

In addition to the revenue requirement and rate increase discussed above, NB Power is seeking the Board's approval of the following:

- Certain changes to its Financial Risk Management Policies, and those of New Brunswick Energy Marketing Corporation, to better reflect the environment in which the Corporation operates (refer to Section 8 Financial Risk Management Policy Updates for details pertaining to these proposed changes);
- An increase of $1.00 per month in the rental fee charged for hot water heaters (refer to Section 4.3 Miscellaneous Revenue for details pertaining to this proposed increase);
- An increase of $11.11 in the Service Call Fee charged to customers for certain service calls (refer to Section 4.3 Miscellaneous Revenue and Appendix AA Service Call Fee Rate Analysis 2022 for details pertaining to this proposed increase).

### 2.4 Goals, Objectives and Strategic Initiatives[2]

NB Power is on a path to transformation. Our attention is focused on areas that support our transformation and establishe the baseline to sustain the changes while keeping employees safe and productive and improving on the services our customers are expecting.

With nearly $5 billion in debt, NB Power is constrained in its ability to transition to a high performing utility. The company is dealing with increased electrification, rising interest rates and fuel prices, aging assets and asset investment requirements, and decarbonization requirements. Developing and executing a solid plan to improve the financial health of NB Power is a threshold issue that must be resolved.

In a period where we are experiencing unprecedently high fuel costs, disruption in the industry, significant inflation, and rate increases that are above average, we owe it to our customers to ensure we are operating as efficiently, effectively and as leanly as possible. To be successful in optimizing our costs and service offerings, we must engage employees and the union leadership, build trust in the organization, unlock potential and enable culture change.

The industry is moving toward net zero to protect our environment. We need to establish our path and the timing on the transition to net zero and more boldly communicate that we are embracing clean energy. While the shift to clean energy is likely to have increased pressure on rates for customers, we must plan now to avoid surprises and rate shock while working to be

- off coal in Belledune by 2030
- net zero within the utility by 2035
- net zero as a country by 2050

Our stakeholders expect reliable, friction-free interaction with us. They expect our services to be consistent with or better than other suppliers with whom they interact, while adapting

[2] This section addresses GRA Minimum Filing Requirements 4, 5, 6, 7, and 8.

and fitting into their busy lifestyles. In addition, they want to understand their energy consumption and, in some cases, be more self-sufficient.

To effectively transform the company, we need to ensure that we prioritize employee recruitment, development, engagement, and retention. Employees are critical to our success and are our most important assets and our best ambassadors.
NB Power's Key Performance Measures and areas of focus for the company continue to centre on five areas of excellence, which are:

- Safety
- Customer
- Organizational
- Reliability
- Environmental

This Excellence framework is intended to help improve NB Power's ability to deliver on commitments through better alignment, focus and execution.

Our plans have been developed while the Corporation's Board of Directors and management are in the midst of developing and finalizing a new long-term strategic plan. We have engaged PwC to guide us through a new strategic plan that we will use as our roadmap and a key tool to engage employees. It will also ensure we remain focused and committed to initiatives in alignment with our plans.

PwC is also leading anagement through a cost optimization review to identify areas of the company where we need to become more efficient to reduce our overall costs. Our cost optimization results will lead to more efficient operations and will mitigate future rate increase requirements.

Once the new strategic plan is in place, we will update future business plans to ensure our initiatives and targets align with and support our long-term strategic objectives.

### 2.5 Significant Changes and Developments

Changes to Legislative and Regulatory Framework

Amendments to the *Electricity Act* were made in 2021 to modernize the *Act* and to position NB Power to make improvements to its fiscal health. Changes to section 103 of the *Act* permit NB Power to request Board approval of up to three years of rates with each general rate application. Under section 101, NB Power is now required to file a three-year strategic, financial and capital investment plan with each GRA, rather than the previous requirement for a 10-year plan.

A number of regulatory accounts have been established with the recent amendments to the *Act*. The first is the Energy Efficiency and Demand Response Deferral Account, established under section 117.3, and is intended to enable NB Power to recover investments in efficiency and demand response programs over a ten year period to more closely match the benefit period of such investments. The operating parameters of this deferral account are prescribed in new Regulation 2022-17 *Regulatory Variance Accounts and Deferral Account Regulation*.

In addition to the Energy Efficiency and Demand Response Deferral Account, two regulatory variance accounts were established in section 117.4 of the *Act* that are intended to improve the financial health of NB Power by capturing in-year cost and revenue variances: Energy and Supply Cost Variance Account and the Electricity Sales and Margin Variance Account. These variances will be recovered from or reimbursed to customers, depending on whether the utility under or over collects in a given year compared to approved forecasts.

The Energy and Supply Cost Variance Account records the variance between actual fuel and purchased power expenses in a fiscal year and the approved forecast for those expenses for that fiscal year. Similarly, the Electricity Sales and Margin Variance Account captures in-year variances in electricity sales and margins. The operating parameters for both accounts are prescribed in new Regulation 2022-17. The regulation requires monthly calculations based on the revenue requirements of the Corporation on which rates were approved or fixed by the Board. For the 2022/23 fiscal year only, the Regulation states that NB Power's revenue requirements as approved by its Board of Directors shall be used for the calculations.

The Regulation also prescribes an annual process, separate from the general rate application, for dealing with the recovery or reimbursement of the balances in the two variance accounts. Annually, on or before December 15, NB Power is to file an application with the Board that includes the combined balance in the two variance accounts as of October 31 of that year, a proposed period of fiscal years over which the balance is to be recovered, a proposed amount to be recovered or reimbursed to customers in the following fiscal year, and the resulting rate rider (positive or negative) for each rate class for the following fiscal year. The Board, subject to the minimum and maximum recovery or reimbursement amounts for the following year prescribed in the Regulation, shall determine the period of fiscal years for recovery and the amount to be recovered in the following fiscal year.

The details of the two new variance accounts are included in this General Rate Application evidence so as to provide a complete picture of NB Power's forecasted financial revenues, costs, and statement of financial position. The figures presented represent forecasted variances for 2022/23 and an assumed recovery amount for 2023/24 (the "rate rider adjustment factor") and are included for information purposes only (i.e., not included in the calculation for the revenue requirement). The application to be filed with the Board in December 2022 will reflect actual account balances as of October 31, 2022, which will differ from the figures presented herein.

Further amendments to the *Act* were made in the spring of 2022 to set minimum energy efficiency targets for electricity, to be prescribed by regulation. The [currently draft] *Energy Efficiency Regulation* sets the 2023/24 target as a reduction of 0.5% of NB Power's forecasted total in-province electricity sales in kilowatt hours. Although NB Power's long term Demand Side Management ("DSM") Plan would have eventually resulted in this level of spending, the new targets require these investments to be made sooner than anticipated. The establishment of the Energy Efficiency and Demand Response Deferral Account as mentioned above allows NB Power to defer the additional expenses and amortize them over a ten year period.

In addition, changes were made to Section 117 of the *Act* to establish an Energy Efficiency Fund ("EEF"). With the Federal Low Carbon Economy Fund that currently funds non-electric fuel efficiency programs coming to an end in 2023/24, a gap would be left for these types of programs in the absence of a new funding source. As outlined in new Section 117.23 of the *Act*, the EEF is to be used for the development and delivery of energy efficiency and conservation programs and initiatives for non-electric fuel types and other groups as prescribed by regulation or as set out in the mandate letter from the Minister of Natural Resources and Energy Development. The current draft Regulation sets the value of the fund at $10 million in the 2023/24 test year and prescribes the groups that are eligible as low-income individuals and families, First Nations and not-for-profit-organizations.

<u>Changes to Energy Smart NB</u>

Beginning with this Application, NB Power will no longer be reporting on Energy Smart NB ("ESNB") in a separate section of the evidence.

In the early years of implementing the ESNB plan, most of the work, with the exception of the demand side management ("DSM") programs, was executed outside the company's regular day-to-day operations. The types of projects and activities that once were "future looking" and outside the normal work of the utility – addressing smart grid and other innovation issues, for example – have now become a normal part of NB Power's operations and planning. Thus, "Energy Smart NB", as a separate heading of projects, initiatives, and spending, no longer exists, as the ESNB work has been integrated with NB Power's regular business processes. NB Power will continue to modernize the grid, offer demand side management programs to customers, and look for opportunities to generate new revenue, but not under a stand-alone ESNB plan.

All Minimum Filing Requirements ("MFRs") that specifically reference ESNB will continue to be met. The capital projects that would have been previously identified as Smart Grid are now included under Distribution projects in Table 5.2.1. Any projects greater than $5 million are listed in Table 5.2.3 with detailed descriptions in that section of the evidence. OM&A initiatives greater than $1 million will be reported in Table 3.2.6.

The DSM programs formerly reported under ESNB's "Smart Habits" functional area will have no change in how they are reported except for their name. The programs that are OM&A spending will continue to be captured under the initiatives greater than $1 million, Table 3.2.7 labelled as Demand Side Management. The details about test year spending on DSM programs are still set out in section 3.2 of the evidence with more details and variance analysis filed in the attachments as in previous years.

The work under the former ESNB "Smart Solutions" functional area which focuses on identifying new revenue streams is now considered base spend and will be reported as OM&A under the Distribution division of the company. Any opportunity that demonstrates a positive business case will be brought forward for evaluation and prioritization through NB Power's corporate investment governance process. Opportunities that are chosen to be implemented will be reported accordingly as either an OM&A initiative or a capital project depending on the size and the nature of the spend.

Please refer to Appendix Vi GRA Minimum Filing Requirements Reference Table for more information on specific MFR locations in the evidence.

Refurbishment of Bayside Generating Station

In late January 2022, the Bayside Generating Station experienced a significant equipment failure that caused extensive damage to the gas turbine, resulting in an unexpected and prolonged forced outage. Prior to the failure, NB Power had been exploring the opportunity to replace the turbine with an upgraded unit with improved efficiency and increased operational flexibility. Initial analysis suggested that this upgraded unit would have a payback period of less than four years. NB Power was contemplating proceeding with this upgrade in 2023/24. However, the unanticipated turbine failure resulted in a decision to advance the turbine replacement project to the current year as the most cost effective option. Bayside is expected to be back online by November 2022.

## 2.6 Previous Board Directives and Orders[3]

The following includes the status of Board Directives and Orders that are pertinent to the 2023/24 GRA.

In response to the Board's Decision of October 2, 2020 in Matter 458 – 2020/21 GRA, NB Power provides the following Board Directions and Orders with NB Power responses:

| BOARD DECISION – MATTER 458 (20/21 GRA) | NB POWER RESPONSE |
|---|---|
| **Load Forecast**<br><br>[29] Given that NB Power has conducted the study, the Board will approve the use of the 20-year heating degree day rolling average going forward basis [*sic*]. As indicated by NB Power, the 20-year rolling average has been found to be more accurate. This approach will begin with the 2021-2022 fiscal year. | <br><br>NB Power has budgeted since FY 2021/22 using a 20-year heating degree day rolling average. |
| **Smart Communities Projects**<br><br>[64] The Board approves the capital costs and OM&A expenses for these projects for the test year. NB Power is directed to provide a further and improved level of detail for each of these projects in the next general rate application. A review will be held at that time to determine if these projects are unfolding as planned, and if continued investment is prudent. | <br><br>Refer to Appendix AF i Smart Community Projects for details on the referenced Smart Community projects. |

[3] This section addresses Minimum Filing Requirements 1, 2 and 3.

| BOARD DECISION – MATTER 458 (20/21 GRA) | NB POWER RESPONSE |
|---|---|
| **Energy Smart NB – DSM Programming**<br><br>[102] As a result, NB Power is directed, as part of its review, to consult with Liberty Utilities and other interested alternative heating source industries, in the development of its programs, particularly those programs that are aimed at reducing the winter peak. Where possible, collaboration with other industries should be encouraged.<br><br>[103] Board staff will coordinate the consultation process in the coming months. | In the absence of a consultation process coordinated by Board staff, NB Power has on its own consulted with Liberty Utilities on a number of occasions in respect of efficiency programming. |
| **Approval of Rates**<br><br>[120] Taking into consideration the disallowances associated with the Fuel and Purchase Power expense relating to Pokeshaw Wind Farm, and the Research and Development Opportunities relating to Maritime Iron, the Board approves revenue requirements in the amount of $1,812.8 million.<br><br>[121] With these changes, NB Power is directed to provide the Board, for review, its calculation for a revised rate increase across all customer classes, and include its revised proposed schedules of rates. | NB Power filed its revised schedule of rates for the Board's approval on November 25, 2020. |

In response to the Board's Decision of September 4, 2020 in Matter 452 – Advanced Metering Infrastructure Project, NB Power provides the following Board Directions and Orders with NB Power responses:

| BOARD DECISION – MATTER 452 (AMI) | NB POWER RESPONSE |
|---|---|
| **Monitoring and Metrics**<br><br>[220] It is in the public interest that the ultimate costs and benefits of AMI are transparent. The Board therefore directs NB Power to propose, at the next general rate application, a set of | NB Power filed its proposal with the Board on May 7, 2021. The Board approved the proposed form of quarterly project report, with modifications, by letter dated May 27, 2021. NB |

| BOARD DECISION – MATTER 452 (AMI) | NB POWER RESPONSE |
|---|---|
| metrics or progress indicators to track the project. This should include progress indicators to track the roll-out of the project, as well as its time-line, costs, and the realization of its quantified and non-quantified benefits. The proposal should also include a reporting and review schedule, and a communication plan for stakeholders and ratepayers. | Power has since been filing quarterly project update reports with the Board and posting these reports on its public website in accordance with this approval. |

For a summary table of ongoing compliance with Board Directions and Orders relevant to the Application, please refer to Appendix BC i[4] (NB Power Regulatory Compliance Filings).

## 2.7 Structure of the Evidence[5]

The evidence is structured as follows:

i. Section 1.0 – Business environment and challenges; Basis for rate increase

ii. Section 2.0 – Approvals requested; Goals, Objectives and Strategic Initiatives; Significant changes and developments; Previous Board directives and orders; Structure of the evidence; Table legends

iii. Sections 3.0, 4.0, 5.0, and 6.0 – Budgeted revenue requirement with details on various expense components; Information on various revenue streams and budgeted capital expenditures. This part of the evidence also includes:
- Explanations of the variances between the 2023/24 Budget and the 2022/23 Budget (labelled as "Variance Analysis 1" in the tables)
- Additional explanations of variances are provided in following Attachments:
  - Attachment 1 - the variance between the 2022/23 Forecast and the 2022/23 Budget (labelled as "Variance Analysis 2" in the tables), and

[4] This addresses Minimum Filing Requirement 3.
[5] This section addresses Minimum Filing Requirement 24.

- Attachment 2 - the variance between 2021/22 actuals and 2021/22 Budget (labelled as "Variance Analysis 3" in the tables)
- Attachment 3 - the variance between 2020/21 actuals and 2020/21 Board approved revenue requirement (labelled as "Variance Analysis 4" in the tables)

iv. Sections 7.0 and 8.0 – Updates on financial accounting and financial risk management policies

v. Section 9.0 – Class cost allocation studies

vi. Section 10.0 – Rate design

## 2.8 Table Legends

The application includes tables and text that references the following legends:

2023/24B = Budget
2022/23E = Forecast
2022/23B = Budget
2021/22A = Actuals
2021/22B = Budget
2020/21A = Actuals
2020/21R = the last Board Approved Revenue Requirement

# 3.0 REVENUE REQUIREMENT[1]

The revenue requirement of NB Power for the 2023/24 fiscal year is set out in Table 3.0.1, column 1 below. The revenue requirement includes net earnings of $13.9 million.

**Table 3.0.1**

**NB Power Corporation**
**Budgeted Revenue Requirement**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Fuel and purchased power expense | $ 1,092.0 | $ 1,562.9 | $ 688.9 | $ 1,008.8 | $ 685.7 | $ 831.1 | $ 661.5 | $ 403.1 | $ 873.9 | $ 323.2 | $ 169.6 |
| (2) | Operations, maintenance and administration | 596.4 | 536.8 | 536.8 | 537.5 | 520.5 | 507.7 | 507.1 | 59.6 | (0.1) | 17.0 | 0.6 |
| (3) | Depreciation and Amortization | 368.7 | 344.3 | 342.9 | 343.9 | 329.6 | 321.1 | 330.9 | 25.7 | 1.4 | 14.3 | (9.8) |
| (4) | Taxes | 54.0 | 52.6 | 53.5 | 50.5 | 50.2 | 48.8 | 49.0 | 0.4 | (0.9) | 0.3 | (0.3) |
| (5) | Finance costs and other income | 213.3 | 202.6 | 181.4 | 189.2 | 196.1 | 144.8 | 209.6 | 31.9 | 21.2 | (7.0) | (64.8) |
| (6) | Net change in regulatory balances | (15.8) | (42.9) | 12.8 | 13.8 | 12.8 | 13.5 | 13.9 | (28.6) | (55.7) | 0.9 | (0.4) |
| (7) | Rate rider adjustment factor[2] | (7.9) | - | - | - | - | - | - | (7.9) | - | - | - |
| (8) | Net earnings | 13.9 | 32.5 | 39.8 | 80.6 | 67.6 | (4.2) | 40.9 | (25.8) | (7.3) | 13.0 | (45.1) |
| (9) | **Total revenue requirement** | $ 2,314.6 | $ 2,688.7 | $ 1,856.2 | $ 2,224.3 | $ 1,862.6 | $ 1,862.9 | $ 1,813.0 | $ 458.4 | $ 832.5 | $ 361.6 | $ 49.8 |

Note to reader: Financial tables reflect differences due to rounding.

[1]This section addresses Minimum Filing Requirements 9, 15, 27 and 28

[2] The rate rider adjustment is related to previous year supply and sales variances. To ensure only actual costs are charged to customers, this amount is offset in Net change in regulatory balances.

**Variance 1 (Table 3.0.1) Increase of $458.4 million – Line 9, Column 8 (2023/24B vs 2022/23B) [3]**

The total revenue requirement is budgeted to be $2,314.6 million (Table 3.0.1, line 9, column 1) in 2023/24, an increase of $458.4 million (Table 3.0.1, line 9, column 8) compared to the 2022/23 NB Power Board approved budget. The largest contributing factor to this increase is the change fuel and purchased power expense of $403.1 million. A significant portion ($274.4 million) of the fuel and purchased power variance is associated with the cost to supply out-of-province sales, with the increase being driven by increased out-of-province sales volumes and increased cost to supply out-of-province sales due to increases in fuel and purchased power prices. Out-of-province fuel and purchased power costs are more than offset by out-of-province revenue. The remaining fuel and purchased power variance of $128.7 million relates to the cost to supply in-province load which is mainly due to increases in fuel and purchased power prices.  Further variance explanations for the changes in the total revenue requirement are included by component in the applicable sections.

**Impact of 2023/24 Proposed Rate Increase**

The 2023/24 revenue requirement includes an 8.9 per cent increase in rates across all customer classes which equates to an increase in revenue of $135.8 million. Please refer to Table 10.4 in Section 10.0 for additional information.

Please note that the variance explanations for Variances 2, 3 and 4 that are shown within the evidence tables are contained within:

- Attachment 1 – Variance Analysis 2, 2022/23 FORECAST VS 2022/23 NB POWER BOARD APPROVED BUDGET REVENUE REQUIREMENT VARIANCE ANALYSIS
- Attachment 2 – Variance Analysis 3, 2021/22 ACTUALS VS 2021/22 NB POWER BOARD APPROVED BUDGETED REVENUE REQUIREMENT VARIANCE ANALYSIS
- Attachment 3 – Variance Analysis 4, 2020/21 ACTUALS VS 2020/21 NB POWER BOARD APPROVED REVENUE REQUIREMENT VARIANCE ANALYSIS

[3] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

Supporting financial information is being provided as follows:

- Appendix Ai – 2019/20 NB Power Audited Consolidated Financial Statements[4]
- Appendix Bi – 2020/21 NB Power Audited Consolidated Financial Statements[4]
- Appendix Ci – 2021/22 NB Power Audited Consoldiated Financial Statements[4]
- Appendix AB – NB Power Three-Year Plan 2024 to 2026[5]
- Appendix BA – Detailed Financial Statements – Redacted
- Appendix CONF Rii – Detailed Financial Statements (Confidential-Redacted) and Appendix CONF Ri – Detailed Financial Statements (Confidential-Restricted). The confidential version of this document is being filed under the Board's policy on confidentiality.
- Appendix O – 2023/24 NB Power Capital Projects
- Appendix Wi – 2019/20 NB Power Annual Report[4]
- Appendix Xi – 2020/21 NB Power Annual Report[4]
- Appendix Yi – 2021/22 NB Power Annual Report[4]

**Reconciliation between the 2020/21 proposed and approved revenue requirement**

Table 3.0.2 below is provided to reconcile the 2020/21 proposed revenue requirement with the 2020/21 Board approved Revenue Requirement (as per the Board decision of October 2, 2020).

[4] This addresses Minimum Filing Requirement 21.
[5] This address the Elecricity Act requirement to file a 3-year strategic, financial and capital investment plan.

**Table 3.0.2**

**Reconciliation of 2020/21R EUB Approved Revenue Requirement**

**NB Power Corporation**
**Budgeted Statement of Earnings**
**Fiscal Year Ending March 31, 2021**
(in millions $)

| | Component | (1) 2020/21B | (2) EUB Adjustments | (3) EUB Approved 2020/21R |
|---|---|---|---|---|
| | **Revenue** | | | |
| | Sales of power | | | |
| (1) | In-province | $ 1,531.1 | $ (1.4) | $ 1,529.7 |
| (2) | Out-of-province | 195.7 | - | 195.7 |
| (3) | Miscellaneous | 87.6 | - | 87.6 |
| | | **1,814.4** | **(1.4)** | **1,813.0** |
| | **Expenses** | | | |
| (4) | Fuel and purchased power expense | 662.6 | (1.1) | 661.5 |
| (5) | Operations, maintenance and administration | 507.4 | (0.3) | 507.1 |
| (6) | Depreciation and amortization | 330.9 | - | 330.9 |
| (7) | Taxes | 49.0 | - | 49.0 |
| | | 1,550.0 | (1.4) | 1,548.6 |
| | **Operating earnings** | 264.3 | - | 264.4 |
| (8) | Finance costs and other income | 209.6 | - | 209.6 |
| (9) | Net change in regulatory balance | 13.9 | - | 13.9 |
| (10) | **Net earnings** | **$ 40.8** | **$ -** | **$ 40.9** |

Note to reader: Financial tables reflect differences due to rounding

Column 3 in Table 3.0.2 reflects the EUB adjusted costs under Expenses and an equivalent reduction in Revenue by adjusting the average rate increase from 1.9 per cent to 1.8 per cent increase in rates across all customer classes, except for DC Fast Charge and Level 2 Charge rates.

## 3.1 FUEL AND PURCHASED POWER[1]

Fuel and purchased power costs represent approximately 47 per cent of NB Power's total revenue requirement. NB Power has a diverse portfolio of generation resources and power purchase agreements ("PPAs") from a blend of hydro, wind, solar, nuclear, coal, natural gas, biomass, biogas, oil-fired thermal and combustion turbines. In order to forecast fuel and purchased power expense, NB Power relies on a production modeling/costing program called PROMOD to derive the fuel and purchased power costs. This modeling program is an established and widely used power system simulation model that provides a capability to project power system operations and production costs and revenues based on certain assumptions.

The PROMOD program optimizes the economic scheduling and dispatch of available generation resources, purchased power, and export sales in a manner that results in the least cost energy to meet NB Power's forecast energy obligations to in-province customers. There are also modeling parameters that can alter the pricing of energy to serve various loads. These parameters include but are not limited to: load and price profiles, unit availabilities and characteristics, purchases and sales contract obligations, fuel prices, and system reliability constraints such as must-runs and ancillary service requirements.

There are two loads that are modeled in a PROMOD simulation:

- In-province firm load and interruptible energy sales. Interruptible energy costs are based on the incremental average cost of supply, determined for each of on-peak and off-peak periods.
- Firm and non-firm export sales made by NB Energy Marketing Corporation ("NB Energy Marketing") whenever capacity and energy are not required to serve in-province load.

[1] This section addresses Minimum Filing Requirements 29, 30, 31, 32, 33, 34.

The New Brunswick system includes base load units and must-run units in a single area model. Interconnection purchases and sales with neighbouring utilities are modelled with load and pricing profiles. The dispatch hierarchy includes dispatchable and non-dispatchable unit generators such as hydro, nuclear, wind power, natural gas, coal, oil, diesel, and purchases. All available resources are stacked in an ascending order of dispatch costs, subject to certain modelling constraints which include system reliability constraints, contract obligations, and unit characteristics.

Based on modelling assumptions, PROMOD calculates the estimated fuel and purchased power cost to serve NB Power's forecasted in-province load requirement and export sales. NB Power, with the assistance of NB Energy Marketing, continually looks for ways to mitigate the impact of fuel cost increases. For example, NB Energy Marketing takes advantage of electricity purchases where possible to displace more costly internal thermal generation.

Key modelling assumptions for the 2023/24 fiscal year included in the production modelling program include:

- Load forecast based on the 10-Year load forecast provided in Appendix AD i., 2023 to 2033 Load Forecast
- Long-term median hydro flows are based on the same values presented in Matter 430 (the Potential Hydro Energy study provided in Matter 336 updated for recent history). The long term median has been reduced by 13.6 GWh as a result of the expected retirement of the Milltown Generating Station in July 2023. This reduction was partially offset by an increase of 8.6 GWh as a result of the upgrade to Nepisiguit Generating Station in January 2023
- Heavy fuel oil, natural gas, coal, pet-coke, purchased power, and foreign exchange estimates are based on forward prices and market indications as of June 7, 2022
- Export sales are based on information provided by NB Energy Marketing. Existing standard offer service contracts are assumed to be retained where, in the judgment of NB Energy Marketing, it would be capable of submitting a competitive bid. Other

short term export sales are modelled when there are economic opportunities to sell into the market

- Coleson Cove Generating Station units will operate on heavy fuel oil. There are planned outages included for Coleson Cove Generating Station Units #2 and #3 in 2023/24
- Belledune Generating Station will operate on a fuel blend (by weight) of 28 per cent petroleum coke, 72 per cent Colombian coal
- There is a 73 day planned outage for Belledune Generating Station scheduled for 2023/24
- There is a 31 day planned outage for Bayside Generating Station scheduled for 2023/24
- Point Lepreau Nuclear Generating Station ("PLNGS") assumed capacity factor will be 88.9 per cent, based on a planned outage of 27 days, and a budgeted forced outage rate for 2023/24 of four per cent.

NB Power regularly reviews modelling assumptions within PROMOD in an effort to align forecasted results with historical operations and to capture operational and system changes. Major assumption changes in this filing include:

- The retirement of the Milltown Generating Station in July 2023
- The increase in output from the Nepisiguit Generating Station resulting from the turbine upgrade in January 2023
- The inclusion of the expected updates to the New Brunswick Carbon Output Based Pricing System ("OBPS") (refer to section "Carbon Policy" below)
- Increased maximum net generation output of PLNGS from 660 MW to 663 MW as a result of the high pressure turbine replacement during the 2022 outage
- Bayside Gas Turbine Project with an expected completion of November 2022.
- Removal of petcoke from Coleson Cove Generating Station unit #3 starting in January 2023 due to relocation of NB Power's berth at the Port of Saint John and expected costs associated with replacing the storage tent. Additionally, the cost reduction

compared to the price of heavy fuel oil caused by the use of petcoke narrowed substantially.

- Reduction of the output of the Kent Hills Wind farm PPA as a result of the turbine failure in September 2021. The full production is expected to return by September 2023
- The addition of the 1.63 MW Shediac Solar project starting September 2022, which will produce 2.4 GWh annually
- Removal of the Pokeshaw and Chaleur Ventus LORESS projects that are no longer proceeding
- Removal of the HSF Foods Embedded Generation PPA due to the counterparty ending operation
- Costs associated with operation of Millbank, Ste Rose and Grand Manan generating stations during contingency situations were included outside of the PROMOD simulation.

For the 2023/24 fiscal year the Nova Scotia Opportunity Transaction Margin Adjustment is $2 million. This includes the benefits from the on-going joint dispatch initiative between NB Power and Nova Scotia Power and non-firm export sales to Nova Scotia. The benefits for the test year budget are included as an offset to purchased power expenses (Table 3.1.2, line 6, column 1). These benefits are not modelled within the PROMOD simulation. Please refer to the section "Joint Dispatch"  below for additional information.

Detailed production modelling inputs and outputs of PROMOD are contained in Appendix I 2023-24 PROMOD Input Output Report[2].  The confidential version of this report can be found in Appendix CONF A i. and Appendix CONF A ii.  These reports are being filed under the Board's policy on confidentiality.

[2] This addresses Minimum Filing Requirements 29, 30, 32, 33 and 34.

New power purchase agreements entered into since the 2020/21 GRA can be found in Appendix CONF C through to Appendix CONF Q.[3] These are being filed under the Board's policy on confidentiality.

**Carbon Policy**

In 2021 the Government of New Brunswick's Output Based Pricing System was approved by the federal government until December 2022. The federal government committed to re-evaluating plans and pricing for 2023 going forward. Consequently, the federal government amended the minimum national stringency standard (the "federal backstop") that all provincial systems must meet to ensure they are comparable and effective in reducing greenhouse gas emissions. The government of New Brunswick worked with Environment and Climate Change Canada to develop a carbon pricing plan submission to meet the revised minimum stringency standard. The proposed New Brunswick carbon pricing system sets a price for $CO_2$ equivalent ($CO_2e$) emissions from generators that emit more than 50 kilotonnes of emissions annually and that exceed the following calendar year output based standards:

- For generators using solid fuels - 811 t/GWh in 2022, 780 t/GWh in 2023, 765 t/GWh in 2024 and 725 t/GWh in 2025
- For generators using liquid fuels - 795 t/GWh in 2022, 668 t/GWh starting in 2023 for all remaining years
- For generators using gaseous fuels - 420 t/GWh in 2022, 395 t/GWh starting in 2023 for all remaining years

The price on emissions from generators that exceed the limits is $50/tonne in 2022 and rises by $15/tonne each year to a final price of $170/tonne in 2030.

The New Brunswick carbon pricing system has been integrated into the dispatch within the PROMOD simulation. As a result, all associated costs are included in the 2023/24 test year and the 2022/23 forecast for fuel and purchase power costs.

[3] This addresses Minimum Filing Requirement 31.

The federal government is currently assessing the New Brunswick government's carbon pricing plan. If the plan is not accepted, NB Power may be subject to the federal OBPS and higher carbon costs.

**Joint Dispatch**[4]

The joint dispatch initiative was developed to encourage greater co-operation with regards to generation dispatch between NB Power and NS Power in an effort to reduce energy costs for both utilities. After an initial pilot project, the parties entered a final agreement in December 2016 with an initial term of one year, automatically renewing for successive one-year terms, subject to rights of termination on sixty days written notice.

The joint dispatch initiative modifies the generation dispatch of each utility to the benefit of both parties. The initial generation dispatches for New Brunswick and Nova Scotia are conducted independently by NB Power and NS Power, respectively. NB Energy Marketing and the NS Power marketing group then schedule transactions under the joint dispatch initiative week-ahead, day-ahead or hour-ahead. A final optimization is completed by the system operators based on current operating conditions and the marginal costs in each province to capture additional real time opportunities.

The benefit resulting from a single transaction is the avoided cost of generation for either utility resulting from that transaction. This benefit is shared equally between the two parties and is calculated as the difference between the marginal unit price for NB Power and the marginal unit price for NS Power multiplied by the volume of transacted energy.

Please refer to Appendix CONF B, Export Sales Confidential[5] for further information. This information is being filed under the Board's Policy on Confidentiality.

[4] This section addresses Minimum Filing Requirement 38.
[5] This section addresses Minimum Filing Requirement 38.

## 3.1a FUEL AND PURCHASED POWER EXPENSE[1]

NB Power is subject to commodity risks and engages in financial transactions to mitigate market price exposures associated with fuel and purchased power expense in accordance with the Financial Risk Management policies established for NB Power and NB Energy Marketing. These transactions are completed to increase the overall predictability of fuel and purchased power expense and reduce the impact of significant market movements. In compliance with these policies, transactions are completed in advance to mitigate market price exposures related to commodities such as electricity purchases, heavy fuel oil, natural gas, coal, uranium, and foreign exchange risk associated with fuel and purchased power expenses and firm export contracts.

This practice results in increased predictability in fuel and purchased power expense. Current market prices will only have an impact to the extent that actual exposures or requirements vary from budgeted requirements or to the extent that exposures were not fully hedged. Due to the fact that transactions are completed 18 to 24 months in advance, the full impact of current market price movements will only be realized 18 to 24 months out in the future.

In 2022, world and North American commodity prices have been extremely volatile, driven primarily by the economic recovery following the COVID-19 pandemic and the war in Ukraine. As a result of this volatility, NB Power has spent considerable time evaluating the assumptions used in preparing the budget for the 2023/24 test year.

The market variations discussed in detail below have increased fuel and purchased power costs by approximately $403.1 million in the 2023/24 test year budget when compared to the 2022/23 budget. The cost to supply in-province customers has increased by $128.7 million (approximately $25.9 million for industrial interruptible customers and $102.8 million for firm in-province loads). A significant portion of the total cost increase ($274.4 million) is

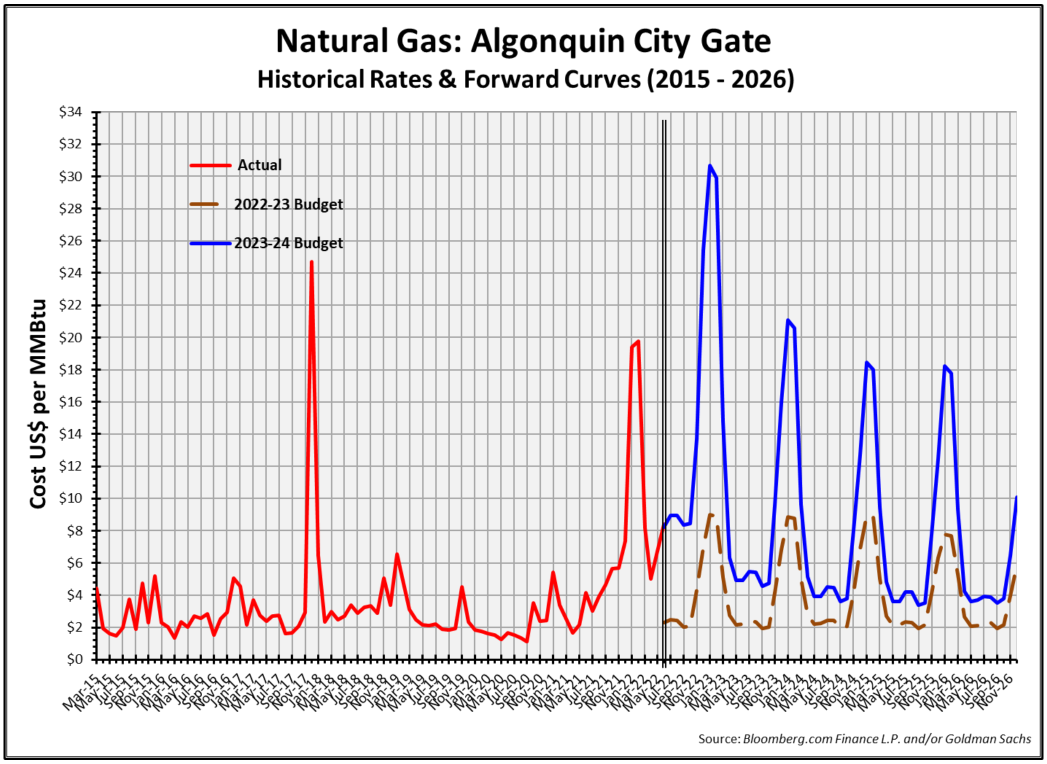
[1] This section addresses Minimum Filing Requirements 35, 36, 37 and 39.

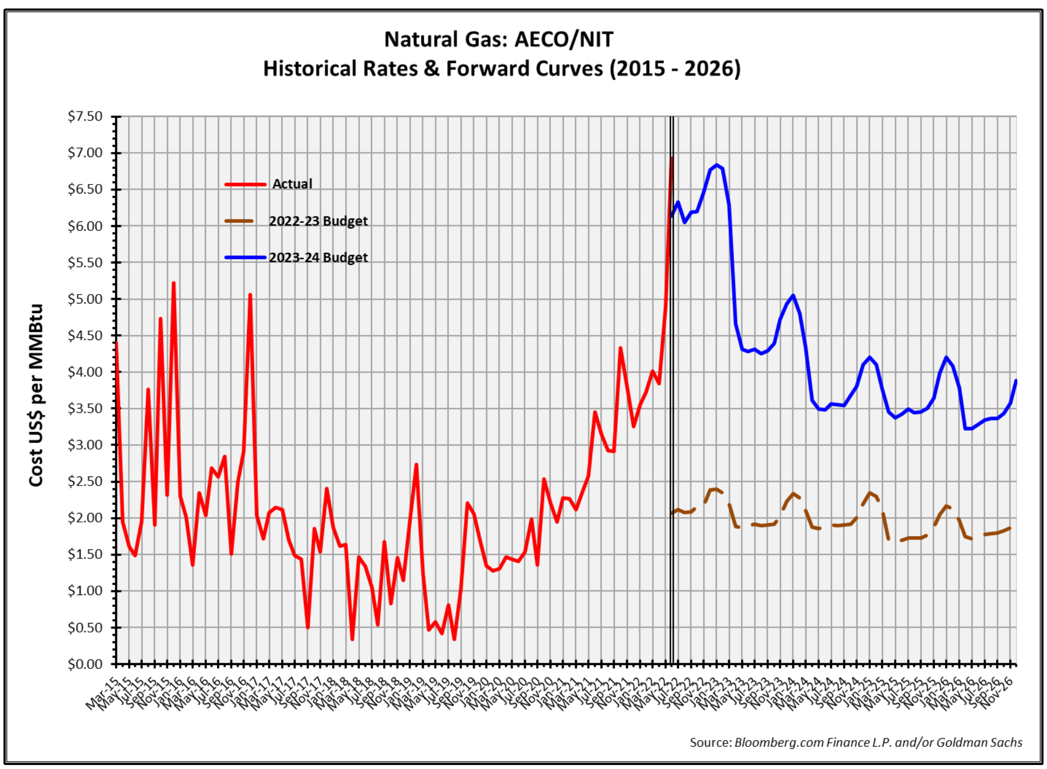
related to forecasted increases of export loads which have an offsetting increase in export sales revenues. Details of the increases in export revenues are included in section 4.2 Out of Province Sales.

Natural Gas

Domestic US supply of natural gas to New England is constrained in the winter heating season; consequently, the region imports liquified natural gas (LNG) from the world market. The price of LNG is indexed to the Dutch TTF index and therefore subject to the market variability in Europe. The market price of natural gas at the Algonquin index, which determines spot prices in the Maritimes, has increased by approximately 130 per cent (an increase of $9 to $12 USD per MMBtu) during the three months December to February; by approximately 90 per cent (an increase of $4.5 USD per MMBtu) in March; and by approximately 125 per cent (an increase of $2.5 to $5.5 USD per MMBtu) in the remaining months compared to the prices in the 2022/23 budget.

The following charts show the changes in market conditions from the 2022/23 budget to the 2023/24 test year budget for natural gas at the Algonquin City Gate index (Boston) and the AECO index (Alberta). The historical trend is included for information purposes.


Natural Gas: Algonquin City Gate
Historical Rates & Forward Curves (2015 - 2026)
Cost US$ per MMBtu
Actual
2022-23 Budget
2023-24 Budget
Source: Bloomberg.com Finance L.P. and/or Goldman Sachs

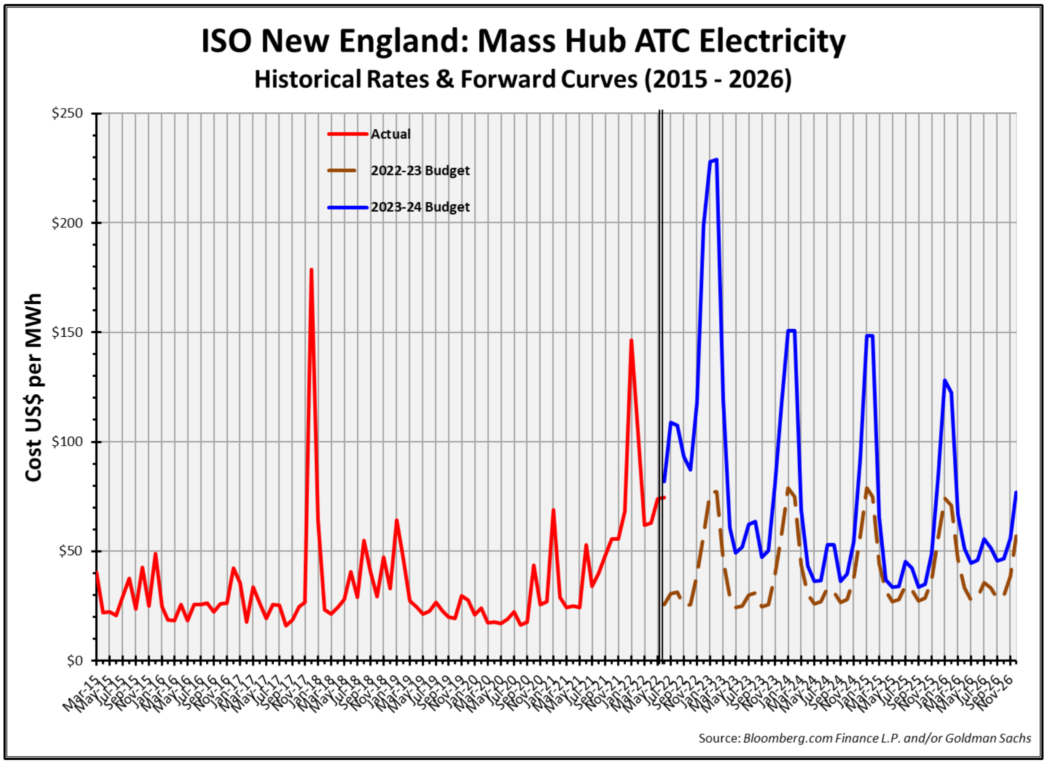

Natural Gas: AECO/NIT
Historical Rates & Forward Curves (2015 - 2026)
Cost US$ per MMBtu
Actual
2022-23 Budget
2023-24 Budget
Source: Bloomberg.com Finance L.P. and/or Goldman Sachs

In the 2023/24 test year, NB Power, consistent with NB Power Board of Directors approved policy deviation, has not hedged expected natural gas volumes related to PPA generation as a result of the uncertainty that exists within the PPA structures in determining the source of natural gas. NB Power has recently started hedging portions of these exposures in months where more certainty exists. These hedges are not reflected in the 2023-24 test year.

Electricity Markets

Electricity market prices typically vary by season; the highest prices are in the winter period (driven by natural gas consumption for home heating in New England), mid-level prices occur in the summer (driven by air-conditioning load) and low prices in the shoulder periods. Prices have increased by approximately 100 per cent (an increase of $60 to $74 USD per MWh) during the three months December to February; by approximately 50 per cent (an increase of $23 USD per MWh) in March; and by approximately 100 per cent (an increase of $22 to $42 USD per MWh) in the remaining months compared to the prices in the 2022/23 budget. This substantive change has caused reordering of unit dispatch in all months.

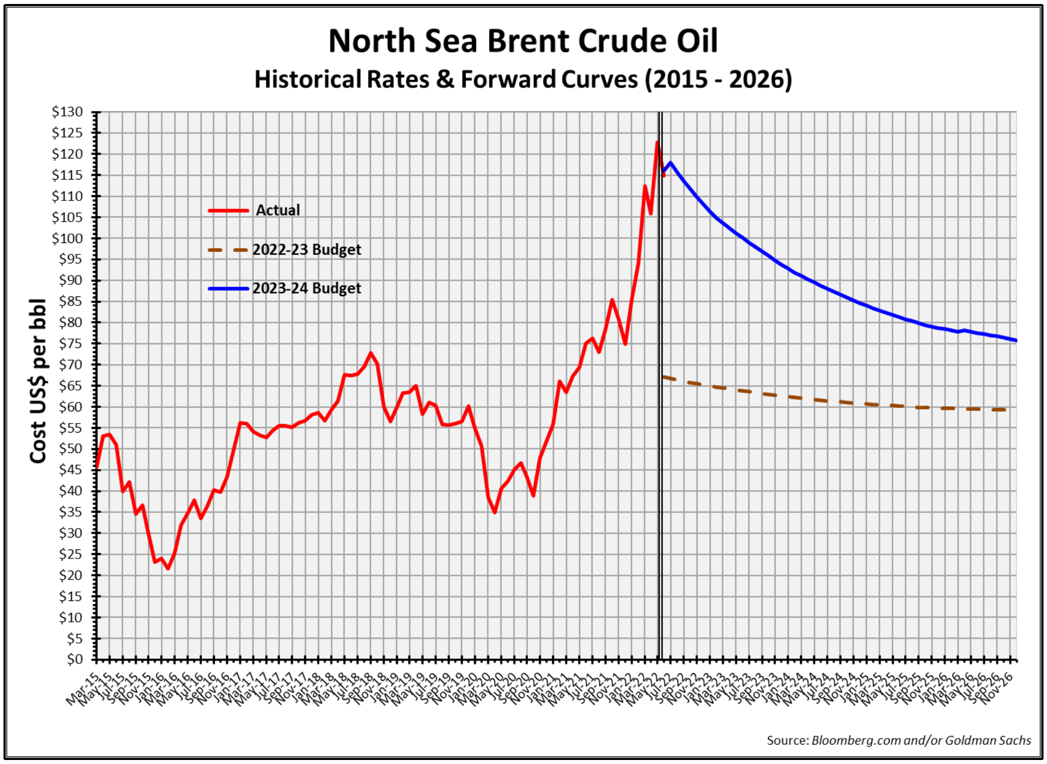
The following chart show the changes in market conditions from the 2022/23 budget to the 2023/24 test year budget for around the clock (ATC) electricity market prices at the Mass Hub index in ISO-NE. The historical trend is included for information purposes.




Heavy Fuel Oil

Heavy fuel oil prices have increased by approximately 50 per cent for the 2023/24 test year compared to the 2022/23 budget. This price increase, while large, was not as significant as the electricity market import price increases and therefore has made operation of Coleson Cove generating station more economic, increasing the expected generation from Coleson Cove. Increased electricity market export prices provide additional opportunity for export sales from Coleson Cove generating station.

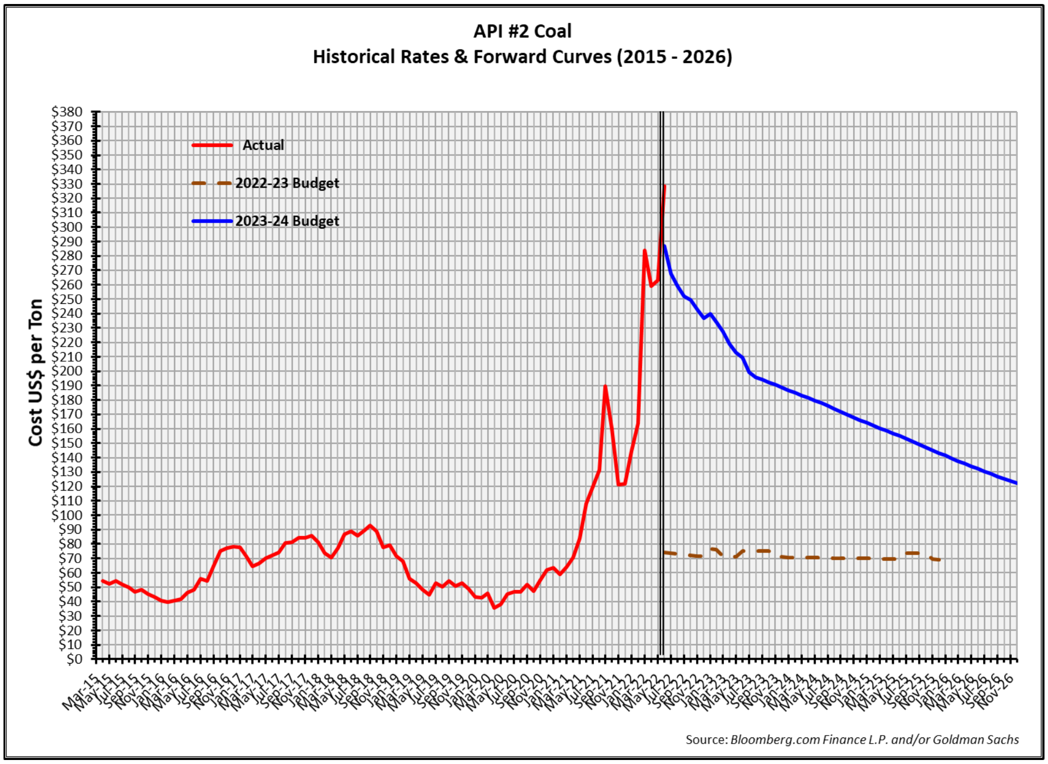
The following chart shows the changes in market conditions from the 2022/23 budget to the 2023/24 test year budget for heavy fuel oil at the Brent crude index. The historical trend is included for information purposes.




<u>Coal and Petcoke</u>

NB Power has a fixed price contract for coal and consequently coal prices NB Power is subject to have remained constant in the 2023/24 test year compared to the 2022/23 budget despite current market volatility. Market prices for coal have increased by approximately 200 per cent (an increase of $120 to $170 USD per ton) over the same period. Petroleum coke prices have increased by approximately 140 per cent (an increase of $87 USD per ton) over this same period creating upward pressure on generation costs from the Belledune generating station as this commodity cannot be hedged.

The following chart shows the changes in market conditions from the 2022/23 budget to the 2023/24 test year budget for coal at the API 2 index. The historical trend is included for information purposes.




Given the rapid change, it is unclear if the upward price trends witnessed this year are going to become the norm or if mitigating effects will apply downward pressure to fuel and purchased power costs. NB Power will continue to monitor price changes and adjust its planned operation to minimize the impact on customers.

A breakdown of the sources of supply for the total load requirement is summarized in Table 3.1.1. below. A breakdown of the costs of the sources of supply for the total load requirement is summarized in Table 3.1.2. A breakdown of the average fuel and purchased power cost per MWh by source of supply is summarized in Table 3.1.3.

**Table 3.1.1**

**NB Power Corporation**
**Total Energy Production and Supply**
Fiscal Years Ending March 31
(in GWh)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Heavy Fuel Oil | 944.4 | 1,553.4 | 191.8 | 704.8 | 155.2 | 229.0 | 248.5 | 752.6 | 1,361.6 | 549.6 | (19.5) |
| (2) | Imported Coal and Other | 2,582.8 | 3,291.9 | 1,865.1 | 2,265.3 | 2,126.1 | 1,762.2 | 3,439.9 | 717.7 | 1,426.8 | 139.2 | (1,677.7) |
| (3) | Natural Gas | 1,759.5 | 821.3 | 1,869.0 | 595.42 | 839.80 | 785.00 | 82.70 | (109.5) | (1,047.7) | (244.4) | 702.3 |
| (4) | Hydro | 2,767.3 | 2,779.7 | 2,764.3 | 2,378.1 | 2,758.9 | 2,637.4 | 2,775.1 | 3.0 | 15.4 | (380.8) | (137.7) |
| (5) | Nuclear | 5,178.2 | 4,044.0 | 4,505.6 | 5,068.1 | 5,550.3 | 4,086.0 | 4,766.1 | 672.6 | (461.6) | (482.2) | (680.1) |
| (6) | **Sub-Total Energy Production** | 13,232.2 | 12,490.2 | 11,195.8 | 11,011.9 | 11,430.3 | 9,499.7 | 11,312.3 | 2,036.4 | 1,294.4 | (418.4) | (1,812.6) |
| (7) | Purchased Power | 6,086.0 | 8,488.0 | 6,275.0 | 9,671.0 | 5,259.0 | 8,947.0 | 5,779.0 | (189.0) | 2,213.0 | 4,412.0 | 3,168.0 |
| (8) | **Total Energy Production and Supply** | 19,318.2 | 20,978.2 | 17,470.8 | 20,682.9 | 16,689.3 | 18,446.7 | 17,091.3 | 1,847.4 | 3,507.4 | 3,993.6 | 1,355.4 |

Note to reader: Financial tables reflect differences due to rounding

**Table 3.1.2**

**NB Power Corporation**
**Fuel and Purchased Power Expense**
Fiscal Years Ending March 31
(in millions $)

| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Component** | 2023/24B | 2022/23E | 2022/23B | 2021/22A | 2021/22B | 2020/21A | 2020/21R | Variance 1 (1)-(3) | Variance 2 (2)-(3) | Variance 3 (4)-(5) | Variance 4 (6)-(7) |
| (1) | Heavy Fuel Oil | $ 166.2 | $ 262.3 | $ 23.4 | $ 92.4 | $ 20.1 | $ 45.0 | $ 37.0 | $ 142.8 | $ 238.9 | $ 72.3 | $ 7.9 |
| (2) | Imported Coal and Other | 154.7 | 165.8 | 91.4 | 105.6 | 94.6 | 86.7 | 135.8 | 63.2 | 74.4 | 11.0 | (49.1) |
| (3) | Natural Gas | 141.0 | 109.5 | 99.4 | 55.3 | 46.1 | 50.1 | 5.5 | 41.7 | 10.2 | 9.1 | 44.6 |
| (4) | Hydro | - | - | - | - | - | - | - | - | - | - | - |
| (5) | Nuclear | 33.5 | 28.6 | 29.6 | 35.4 | 36.8 | 27.2 | 29.0 | 4.0 | (0.9) | (1.4) | (1.8) |
| (6) | **Sub-Total Fuel expense** | $ 495.4 | $ 566.2 | $ 243.7 | $ 288.7 | $ 197.6 | $ 209.0 | $ 207.3 | $ 251.7 | $ 322.5 | $ 91.0 | $ 1.7 |
| (7) | Purchased Power expense | 596.6 | 996.6 | 445.2 | 720.2 | 488.0 | 622.2 | 454.2 | 151.3 | 551.4 | 232.1 | 167.9 |
| (8) | **Total fuel and purchased power expense** | $ 1,092.0 | $ 1,562.9 | $ 688.9 | $ 1,008.8 | $ 685.7 | $ 831.1 | $ 661.5 | $ 403.1 | $ 873.9 | $ 323.2 | $ 169.6 |

Note to reader: Financial tables reflect differences due to rounding

**Table 3.1.3**

**NB Power Corporation**
**Average Fuel and Purchased Power Cost per MWh**
Fiscal Years Ending March 31
($/MWh)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Heavy Fuel Oil | $ 175.95 | $ 168.84 | $ 121.75 | $ 131.13 | $ 129.36 | $ 196.44 | $ 149.05 | 54.19 | 47.09 | 1.77 | 47.39 |
| (2) | Imported Coal and Other | 59.89 | 50.37 | 49.02 | 46.62 | 44.51 | 49.20 | 39.48 | 10.87 | 1.35 | 2.11 | 9.72 |
| (3) | Natural Gas | 80.16 | 133.34 | 53.16 | 92.82 | 54.94 | 63.85 | 66.19 | 27.00 | 80.18 | 37.89 | (2.35) |
| (4) | Hydro | - | - | - | - | - | - | - | - | - | - | - |
| (5) | Nuclear | 6.48 | 7.08 | 6.57 | 6.98 | 6.62 | 6.66 | 6.09 | (0.09) | 0.52 | 0.35 | 0.57 |
| (6) | **Fuel expense per MWh** | 37.44 | 45.33 | 21.77 | 26.21 | 17.29 | 22.00 | 18.33 | 15.67 | 23.57 | 8.93 | 3.67 |
| (7) | Purchased Power expense per MWh | 98.02 | 117.42 | 70.95 | 74.47 | 92.80 | 69.54 | 78.60 | 27.07 | 46.46 | (18.33) | (9.06) |
| (8) | **Average Fuel and Purchased Power per MWh** | $ 56.53 | $ 74.50 | $ 39.43 | $ 48.78 | $ 41.08 | $ 45.06 | $ 38.71 | 17.09 | 35.07 | 7.69 | 6.35 |

Note to reader: Financial tables reflect differences due to rounding.

Values in this table are weighted annual averages.

**Variance 1 (Table 3.1.2) Increase of $403.1 million - Line 8, Column 8 (2023/24B vs 2022/23B) [2]**

Fuel and Purchased Power expense is budgeted to be $1,092.0 million as presented in Table 3.1.2, line 8, column 1. This represents an increase of $403.1 million (Table 3.1.2, line 8, Column 8) compared to the 2022/23 budget.

The major factors contributing to the variance are summarized below. All variances are expressed in Canadian dollars and are inclusive of foreign exchange impacts. Benefits of changes in hydro and nuclear generation are calculated using expected market prices.

- Higher forward electricity market prices year over year, expected purchase costs inclusive of hedging effects will increase by $176.1 million
- Higher heavy fuel oil prices combined with increased utilization of the Coleson Cove generating station increase costs by $139.7 million
- Higher standard offer service export loads in southern Maine of 1050 GWh, new standard offer service exports loads in Connecticut of 237 GWh and higher additional export load of 685 GWh (inclusive of losses) result in a $74.2 million increase in costs
- Higher average imported coal, petcoke and other fuel prices combined with increased utilization of the Belledune Generating station resulting in an increase of $59.5 million
- Increase in carbon tax due to higher rates and dispatch changes of $17.6 million
- Natural gas price increases inclusive of hedging impacts increase costs by $12.3 million
- Decreases in in-province wind, Locally Owned Renewable Energy Small Scale Program ("LORESS") purchases and Embedded Generation purchases offset by Large Industrial Renewable Energy Purchase Program ("LIREPP") increases, result in a decrease of 65 GWh which increase costs by $5.9 million due to expected PPA price increases year over year

[2] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

- In-province load (inclusive of losses) increased by 292 GWh resulting in $2.6 million increase in costs
- Higher non-utility generator prices $3.3 million
- Higher water storage fees of $2.4 million
- Other smaller individual variances $0.5 million

Offset by:

- Decrease in supply costs due to more energy from PLNGS $91.0 million

## 3.1b RENEWABLE ENERGY RESOURCES[1]

**Renewable Portfolio Standard ("RPS") Progress Report**

This section provides the current status of NB Power's obligations under the *Electricity from Renewable Resources Regulation-Electricity Act* also known as the Renewable Portfolio Standard ("RPS"). This program requires 40 percent of in-province electricity sales to be sourced from renewable resources.

**a) Qualified Renewable Energy under RPS**

NB Power continues to be a leader in renewable and non-emitting energy. NB Power has entered into power purchase agreements with a wide range of counterparties, including First Nations, community groups, industry, small producers and other large renewable suppliers to obtain renewable energy in a cost effective manner for the betterment of all customers.

As a result of this proactive approach, NB Power was able to meet this requirement in 2018/19 (two years in advance of the deadline) and has sourced an average of 44 per cent renewable generation for the last four years. NB Power is forecasting sourcing 35 per cent renewable energy for the 2023/24 test year due to a shortage of in-province renewable generation, due mainly to the Kent Hills wind farm being offline for part of the test year, and increased costs related to the import of renewable energy from out of province. Despite this forecast, NB Power will strive to meet the RPS target in the 2023/24 test year while maintaining the current budgeted costs.

NB Power typically sources approximately 40 percent of its in-province electricity demand from biogas, biomass, hydro, wind and solar resources. In addition, NB Power sources approximately one-third of its in-province demand from non-emitting nuclear power. This results more than 70 per cent of total generation originating from non-emitting sources. The following table summarizes 2020/21 actual performance, 2021/22 actual performance and provides a forecast for 2022/23 and the budget for 2023/24.

[1] This section addresses Minimum Filing Requirements 40, 41 and 42.

**Table 3.1.4**

**NB Power Corporation**
**Renewable Portfolio Standard**
Fiscal Years Ending March 31

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2021/22A | (4) 2020/21A | (5) Variance 1 (1)-(2) | (6) Variance 2 (2)-(3) | (7) Variance 3 (3)-(4) |
|---|---|---|---|---|---|---|---|---|
| (1) | Total In Province Sales (GWh) | 13,936 | 13,923 | 13,498 | 12,983 | 13 | 425 | 515 |
| (2) | Qualified Renewable Energy (GWh) | 4,856 | 5,591 | 5,728 | 6,634 | -735 | -137 | -906 |
| (3) | RPS Percentage of Sales | 35% | 40% | 42% | 51% | -5% | -2% | -9% |
| (4) | Non-Emitting Energy Percentage of Sales | 72% | 69% | 80% | 83% | 3% | -11% | -3% |

The quantity of qualified renewable energy changes year to year. The major drivers of these changes are as follows:

**Variance 1 (Table 3.1.4) Decrease of 735 GWh – Line 2, Column 5 (2023/24B vs 2022/23E)**

- A decrease in qualified out-of-province purchases of 852 GWh due to economic dispatch primarily driven by electricity market price increases
- A decrease of 14 GWh due to the Milltown generating station retirement

Offset by:

- An increase of 63 GWh of NB Power Hydro generation serving in-province loads
- An increase of 45 GWh of transmission connected wind generation
- An increase of 16 GWh in non-utility power purchase agreements in 2023/24 due to
    - an increase of 19 GWh from the LIREPP program
    - a decrease of 4 GWh from hydro PPAs, biomass and embedded generation
    - an increase of 1 GWh from the Shediac solar project
- An increase in NB Power hydro generation of 7 GWh resulting from Nepisiguit Falls generating station upgrade

**Variance 2 (Table 3.1.4) Decrease of 137 GWh – Line 2, Column 6 (2022/23E vs 2021/22A)**

- A decrease in qualified out-of-province purchases of 968 GWh due to economic dispatch and a return to long term forecast NB Power hydro generation
- A decrease of 163 GWh for transmission connected wind generation

Offset by:

- An increase of 972 GWh of in-province NB Power hydro generation due to historically low hydro in 2021/22 actuals
- An increase of 22 GWh in non-utility power purchase agreements in 2022/23 due to
    - an increase of 28 GWh from the LIREPP program
    - an increase in hydro PPA energy of 16 GWh
    - an increase of 6 GWh for embedded generation and biomass energy
    - an increase of 1 GWh from the Shediac solar project
    - a decrease of 29 GWh from the LORESS program

**Variance 3 (Table 3.1.4) Decrease of 906 GWh – Line 2, Column 7 (2021/22A vs 2020/21A)**

- A decrease of 597 GWh for transmission connected wind generation
- A decrease of 122 GWh of in-province NB Power hydro generation
- A decrease in qualified out-of-province purchases of 89 GWh due to economic dispatch
- A decrease of 54 GWh of LORESS program energy
- A decrease of 47 GWh of LIREPP program energy
- A decrease of 6 GWh of biomass energy

Offset by:

- An increase in hydro and embedded PPA energy of 9 GWh

As shown in the following table[2], NB Power has executed power purchase agreements for in province renewable energy totaling 510.9 MW.

| Partner | Type | Location | In Service Date | Megawatt |
|---|---|---|---|---|
| Acciona | Wind | Lamèque | Mar, 2011 | 45.0 |
| Oinpegitjoig LP | Wind | Richibucto | Jan. 2020 | 3.8 |
| TransAlta (Kent Hills 1) | Wind | Kent Hills | Dec. 2008 | 96.0 |
| TransAlta (Kent Hills 2) | Wind | Kent Hills | Nov. 2011 | 54.0 |
| TransAlta (Kent Hills 3) | Wind | Kent Hills | Oct. 2018 | 17.3 |
| Suez | Wind | Caribou Mountain | Oct. 2009[3] | 99.0 |
| Wisokolamson Energy LP | Wind | Riverside-Albert | Nov. 2019 | 18.0 |
| WKB Community Wind Farms Inc. | Wind | Cap-Pele | Aug. 2018 | 2.4 |
| Wocawson Energy LP | Wind | Sussex | Dec. 2019 | 20.0 |
| **Wind Subtotal** | | | | **355.5** |
| AV CELL (LIREPP) | Biomass | Atholville | Jan. 2012 | 21.0 |
| AV Nackawic (LIREPP) | Biomass | Nackawic | Jan. 2012 | 25.6 |
| Irving Pulp and Paper (LIREPP) | Biomass | Saint John | Jan. 2012 | 32.8 |
| JD Irving | Biomass | Chipman | Feb. 2021 | 1.8 |
| Twin Rivers (LIREPP) | Biomass | Edmundston | Jan. 2012 | 38.5 |
| **Biomass Subtotal** | | | | **119.7** |
| Edmundston Hydro Green River | Hydro | Green River | Apr. 2012 | 3.1 |
| Edmundston Hydro Madawaska River | Hydro | Edmundston | Apr, 2012 | 5.5 |
| Hargrove | Hydro | Perth Andover | Dec, 2014 | 1.5 |
| St. George, LP (LIREPP) | Hydro | St George | Jan, 2012 | 15.0 |
| Town of Dalhousie | Hydro | Dalhousie | Oct. 2021 | 0.1 |
| **Hydro Subtotal** | | | | **25.2** |
| Frank's Agriculture Limited | Solar | Mount Pisgah | May, 2018 | 0.1 |
| Net metered customers | Solar | New Brunswick | Feb, 2004 | 3.8 |
| **Solar Subtotal** | | | | **3.9** |
| Chaleur Regional Services | Landfill Gas | Petit-Rocher | Sep. 2018 | 0.8 |
| COGERNO | Landfill Gas | Rivière-Verte | Jun, 2012 | 0.6 |
| Fredericton Regional Solid Waste Commission | Landfill Gas | Fredericton | Jan. 2013 | 2.1 |
| South East Regional Services | Landfill Gas | Moncton | Oct. 2017 | 1.0 |
| **Landfill Gas Subtotal** | | | | **4.5** |
| LaForge Bioenvironmental Inc. #1 | Biogas | Grand Falls | May. 2011 | 0.6 |
| LaForge Bioenvironmental Inc. #2 | Biogas | Grand Falls | Nov. 2014 | 1.5 |
| **Biogas Subtotal** | | | | **2.1** |
| **Total** | | | | **510.9** |

[2] This list addresses Minimum Filing Requirement 40.
[3] Suez has two power purchase agreements, one for 51 MW that became commercial in October 2009 and a second for 48 MW that became commercial in November 2009.

A complete list of all NB Power resources and power purchase agreements can be found in Appendix I 2023-24 PROMOD Input Output Report.

**b) Locally Owned Renewable Energy Projects that are Small Scale ("LORESS") program**

LORESS projects are regulated under Part 2 of the *Electricity from Renewable Resources Regulation – Electricity Act*. This program requires NB Power to endeavor to obtain up to 40 MW of renewable energy from Aboriginal businesses and an additional 40 MW of renewable energy from local entities as defined in the Regulation. A call for expression of interest from Aboriginal businesses to meet the first 40 MW under the program was conducted on January 31, 2016. A second call for expression of interest from local entities to meet the remaining 40 MW was conducted by January 31, 2017. LORESS also includes energy purchased under embedded generation and net metered generation agreements.

As a result of the expression for interest from Aboriginal businesses, power purchase agreements with Wisokolamson Energy Limited Partnership and Wocawson Energy LP were executed. These projects had in-service dates of November 2019 and December 2019 respectively.

As a result of the expression for interest from Local Entities, power purchase agreements with Chaleur Ventus Limited Partnership and Pokeshaw Windfarm Limited Partnership were executed. These developments are no longer proceeding.

The costs associated with these contracts are found in Appendix I 2023-24 PROMOD Input Output Report[4]. The confidential version of this report can be found in Appendix CONF A i. 2023-24 PROMOD Input Output Report Confidential and Appendix CONF A ii. 2023 PROMOD Input Output Report Confidential – Redacted. These reports are being filed under the Board's policy on confidentiality.

[4] This addresses Minimum Filing Requirements 29, 30, 32, 33 and 34.

### c) Large Industrial Renewable Energy Purchase Program

The Large Industrial Renewable Energy Purchase Program ("LIREPP") is mandated under Part 3 of the *Electricity from Renewable Resources Regulation – Electricity Act* which took effect January 1, 2012. This program requires NB Power to purchase renewable energy from qualified large industrial customers' generation facilities. NB Power is able to apply the energy purchased toward meeting the RPS target set out in the Regulation.

The table below provides a summary of the program for the five most recent historical years (2017/18A – 2021/22A), current year budget (2022/23E) and test year budget (2023/24B).

**Table 3.1.5**

**NB Power Corporation**
**LIREPP Program Summary**

(in millions $)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| | **Year** | **LIREPP Discount %** | **LIREPP Rate ($/MWh)** | **LIREPP Energy (MWh)** | **Gross LIREPP Purchases** | **Existing Contract & Resale Benefit** | **Net LIREPP Cost** |
| (1) | 2017/18A | 15.0% | $ 95.00 | 464,858 | $ 44.2 | $ 32.6 | $ 11.6 |
| (2) | 2018/19A | 14.8% | $ 95.00 | 489,342 | $ 46.5 | $ 34.8 | $ 11.7 |
| (3) | 2019/20A | 13.8% | $ 95.00 | 479,389 | $ 45.5 | $ 34.7 | $ 10.8 |
| (4) | 2020/21A | 13.7% | $ 95.00 | 432,362 | $ 41.1 | $ 31.4 | $ 9.7 |
| (5) | 2021/22A | 14.0% | $ 106.91 | 310,370 | $ 33.2 | $ 23.2 | $ 10.0 |
| (6) | 2022/23E | 14.7% | $ 110.54 | 338,303 | $ 37.4 | $ 26.1 | $ 11.3 |
| (7) | 2023/24B | 19.7% | $ 112.75 | 445,924 | $ 50.3 | $ 35.6 | $ 14.7 |

Table 3.1.5, column 7 above includes the Net LIREPP yearly cost that is derived from the cost of the renewable energy purchased less pre-existing benefits and sales revenue of electricity back to the participant.

While the general requirements and parameters are set out in the Regulation, certain assumptions and methodologies are reserved for the Minister of Natural Resources and Energy Development to determine. For more information on the calculation of the LIREPP discount rate, the assumptions and methodologies can be viewed on the New Brunswick Energy and Resource Development website, Large Industrial Renewable Energy Purchase Program page.[5]

[5] http://www2.gnb.ca/content/gnb/en/departments/erd/energy/content/industrial.html

# 3.2 OPERATIONS, MAINTENANCE & ADMINISTRATION (OM&A)[1]

**OM&A OVERVIEW, INCLUDING THE OM&A PLANNING PROCESS**

OM&A expense relates to the operations, maintenance and administration of NB Power's generating facilities, the distribution and transmission infrastructure that is used to deliver electricity to more than 400,000 customers by way of over 21,500 km of distribution lines and 6,800 km of transmission lines, and corporate services. OM&A also includes activities that support modernizing the grid through investments in technology, educating customers and promoting efficiencies, and offering new products and services.

Historically, planning and forecasting in the utility industry has had many material uncertainties. Several of the underlying assumptions are subject to variances and changes beyond management's control. Every year management is faced with new pressures relating to on-going operational requirements, inflation, and opportunities relating to changing markets and technologies, and as a result management must be strategic in creating ways to limit these cost pressures. However, the current planning cycle has proven to be particularly difficult due to significant global factors, including exceptional inflationary pressures and the supply chain crisis.

The planning process is an iterative process that commences with bottom-up planning whereby managers and supervisors develop the budget for their respective area to reflect the annual work requirements in order to meet demands. These individual budgets are then consolidated into the combined budget which provides the full picture of the revenue required to cover costs. As part of the top-down aspect of planning and to relieve some of this significant upward rate pressure, management engaged in an aggressive cost review which resulted in proposed OM&A budgets seeing substantial short-term cuts or work deferrals. Management sought to prioritize planned work and manage cost pressures from inflation and supply chain disruptions, while balancing reliability and obligations to our customers. The cost reductions included cuts to discretionary spending, including reductions

[1] This section addresses Minimum Filing Requirements 43 - 60.

in innovation spending, reduction in memberships and subscriptions, as well as scaling back planned work in many areas. These cost reductions or deferrals are short term in nature in order to manage the associated increased risk. As a result of this action, $18.5 million was removed from the OM&A budget and $54.2 million from the capital expenditure budget for 2023/24.

Management recognizes that the removal of $18.5 million in OM&A costs is insufficient. Accordingly, NB Power has a number of critical strategic initiatives underway, including engaging a third party to perform a cost optimization initiative. This initiative is ongoing at the time of filing this Application and the results are therefore not specifically reflected in the 2023/24 budget. Recognizing that savings are anticipated from the cost optimization initiative, management has included a $20 million top-of-the house credit placeholder in the Corporate Services hired services OM&A budget for 2023/24. The actual savings could be realized in various cost categories and thus could impact the amounts currently reflected in the test year.

Management is actively taking the same approach with managing in-year spending and as such has delayed filling most vacancies other than those which are deemed essential to ensure the reliability of critical infrastructure, to provide direct support to customers, or to meet regulatory requirements. In addition, work has been paused in certain areas, such as office building improvements, pending the outcome of the strategic initiatives currently underway.

NB Power remains committed to ongoing continuous improvement and cost management activities and as such has recorded a credit in the hired services category in the OM&A budget of $7.5 million. This is in addition to the $20 million credit mentioned above.

The overall result of management's actions was a $46.0 million reduction to OM&A, of which $18.5 million has been identified, and $27.5 million is to be identified as a result of strategic cost optimization and continuous improvement initiatives underway.

In addition to managing cost increases, Management has also made improvements to the planning process for OM&A expenditures to help achieve the most value for dollars spent. OM&A is divided into two types of expenditures: base OM&A costs and initiative OM&A costs. Base OM&A cost is defined as those required to run the day-to-day activities of the organization. Initiative OM&A cost is defined as being finite in duration, outside of the organization's day-to-day operational core activities, and will either improve performance or solve a problem.

NB Power's Investment Governance Framework, formerly for capital expenditures only, was refreshed to include OM&A initiatives in time for the planning of 2023/24 work and associated expenditures . A new corporate level committee comprising senior management representatives from across the divisions has been established. Known as the Joint OM&A Investment Review Committee, its primary mandate is to collaborate amongst all divisions to ensure appropriate and consistent prioritization of OM&A initiatives in order to garner the most value for the Corporation and its customers. This committee recommends the annual OM&A initiatives plan to the Executive level committee known as the Investment Management Committee ("IMC"). The IMC approves the OM&A initiatives portfolio for inclusion in the budget. Please refer to Appendix AE i. – NB Power Investment Governance Framework for the updated Framework document.

The identification of OM&A initiatives originates from divisional level planning sessions. At the divisional level, senior management teams determine OM&A initiatives they believe should be put forward for prioritization.  All divisions use the same investment rationale template, scoring matrix, and prioritization tool to ensure OM&A initiatives are evaluated consistently as the divisions compete for a limited OM&A initiatives spending envelope. For further information regarding the 2023/24 planned OM&A initiatives please refer to the OM&A Initiatives and Programs narrative, including Table 3.2.6.

OM&A EXPENSE

OM&A expense for NB Power is budgeted to be $596.4 million in 2023/24, as outlined below in Table 3.2.1 (line 7, column 1), which is $59.6 million higher than the 2022/23 NB Power Board approved budget. The increase in OM&A expense results from items such as:

- Increase in regular and term labour expense mainly due to union and non-union increases ($10.7 million), an increase in positions ($6.4 million), and a corresponding increase in benefits expense ($5.0 million) – $23.8 million
- Increase in demand side management (DSM) spending (excluding labour) due to proposed DSM legislated requirements increasing energy efficiency targets - $15.6 million (offset by an increase in DSM regulatory deferral account)
- A reclassification of prior year expenditures relating to the Mactaquac Life Achievement project - $8.8 million
- Increase in resources allocated to operations maintenance activities as opposed to capital outage work at PLNGS mainly due to changes in outage scope and length - $5.2 million
- PLNGS engineering and specialized nuclear support - $4.2 million
- Hired services to support hydro initiatives and maintenance, including waterproofing, grouting & supernatant water disposal - $3.6 million
- Nuclear and conventional generation maintenance backlog reduction initiatives (excluding labour) - $2.9 million
- Inflationary pressures in areas such as hired services (i.e. engineering services, environmental, maintenance, and ERP system support fees), computer software licensing fees, and fleet

Partially offset by

- Planned savings from the cost optimization initiative - $20 million
- Reduction in storm contingency based on five-year historical average - $5.2 million

**Table 3.2.1**

**NB Power Corporation**
**OM&A Expense by Division**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Generation | $ 86.5 | $ 77.2 | $ 76.9 | $ 75.4 | $ 70.5 | $ 71.2 | $ 71.8 | $ 9.5 | $ 0.3 | $ 5.0 | $ (0.7) |
| (2) | PLNGS | 209.4 | 183.7 | 182.9 | 211.4 | 189.9 | 190.7 | 177.8 | 26.5 | 0.8 | 21.5 | 12.9 |
| (3) | Transmission | 47.0 | 42.2 | 43.7 | 39.3 | 39.5 | 40.3 | 37.7 | 3.3 | (1.5) | (0.2) | 2.6 |
| (4) | Distribution | 136.5 | 122.7 | 123.3 | 105.4 | 115.7 | 102.3 | 125.6 | 13.2 | (0.6) | (10.3) | (23.3) |
| (5) | NB Energy Marketing | 2.9 | 2.8 | 2.2 | 2.1 | 2.4 | 1.7 | 2.6 | 0.6 | 0.5 | (0.3) | (0.9) |
| (6) | Corporate Services | 114.2 | 108.2 | 107.8 | 103.7 | 102.5 | 101.5 | 91.6 | 6.5 | 0.4 | 1.2 | 9.9 |
| (7) | **OM&A expense** | $ 596.4 | $ 536.8 | $ 536.8 | $ 537.5 | $ 520.5 | $ 507.7 | $ 507.1 | $ 59.6 | (0.1) | $ 16.9 | $ 0.6 |

## OM&A EXPENSE BY DIVISION

Table 3.2.1 OM&A expense by Division variance explanations for the 2023/24 budget compared to the 2022/23 NB Power Board approved budget are as follows: [2]

[2] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

Generation OM&A

**Variance 1 (Table 3.2.1) Increase of $9.5 million, Line 1, Column 8 (2023/24B vs 2022/23B)**

Generation OM&A is budgeted at $86.5 million (line 1, column 1) in 2023/24, a net increase of $9.5 million (line 1, Column 8) from the 2022/23 NB Power Board approved budget. The increase is mainly due to an increase in hired services and material spending in support of additional hydro facility maintenance activities including outage work and waterproofing, additional spending to address maintenance backlogs at Coleson Cove and Belledune Generating stations (please refer to Table 3.2.6 – Initiatives Greater than $1 million), and a new maintenance support contract for the Bayside generating station related to the installation of the new turbine in 2022/23. In addition, labour costs are higher as a result of assumed collective agreement increases and new power plant operator succession positions (as noted in Table 3.2.4a, line 4).

PLNGS OM&A

**Variance 1 (Table 3.2.1) Increase of $26.5 million, Line 2, Column 8 (2023/24B vs 2022/23B)**

PLNGS OM&A is budgeted at $209.4 million (line 2, column 1) in 2023/24, an increase of $26.5 million (line 2, Column 8) from the 2022/23 NB Power Board approved budget. This increase is primarily required to continue the station's path to industry excellence and the need to improve station reliability based on historical performance challenges which are being completed through various improvement initiatives including: priority backlog reduction initiative, including the addition of 39 term positions required to execute this work (Table 3.2.4a, line 24); increase in labour costs due to negotiated union wage increases; and performing more operations maintenance work (and less capital outage work).

Transmission OM&A

**Variance 1 (Table 3.2.1) Increase of $3.3 million, Line 3, Column 8 (2023/24B vs 2022/23B)**

Transmission OM&A is budgeted at $47.0 million (line 3, column 1) in 2023/24, an increase of $3.3 million (line 3, Column 8) from the 2022/23 NB Power Board approved budget. This increase is primarily due to a net increase in labour costs due to negotiated union wage increases and new labour positions as noted in Table 3.2.4a, which is driven by succession requirements and additional positions in support of existing programs, projects, and baseload work, also noted in Table 3.2.4a; partially offset by a higher labour allocation to capital. Other increases are associated with higher vehicle maintenance and fuel related costs due to aging vehicle infrastructure and higher fuel costs and an increase in the out-of-province travel budget for resumption of travel to participate in person on various committees.

Distribution OM&A

**Variance 1 (Table 3.2.1) Increase of $13.2 million, Line 4, Column 8 (2023/24B vs 2022/23B)**

Distribution OM&A is budgeted at $136.5 million (line 4, column 1) in 2023/24, an increase of $13.2 million (line 4, Column 8) from the 2022/23 NB Power Board approved budget. The increase is primarily related to additional energy efficiency related spending, resulting from proposed new requirements under the *Electricity Act*, a portion of which is additional positions (line 16, Table 3.2.4a). Additional increases are related to material costs to address higher historical trends associated with increased customer demand work, unplanned outages, and losses due to vandalism activities. As well, vehicle maintenance and fuel costs have increased as a result of an aging vehicle infrastructure and higher fuel costs due to inflation. There is also a reduced labour allocation to capital based on the capital plan requirements. Partially offsetting these increases is a reduction in the storm contingency which is based on the most recent five-year average actual storm costs, a one-time reduction to vegetation management spending in 2023/24 to help offset other budget pressures, and the completion and cancellation of specific smart community related programs.

NB Energy Marketing OM&A

**Variance 1 (Table 3.2.1) Increase of $0.6 million, Line 5, Column 8 (2023/24B vs 2022/23B)**

NB Energy Marketing OM&A is budgeted at $2.9 million (line 5, column 1) in 2023/24, an increase of $0.6 million (line 5, Column 8) from the 2022/23 NB Power Board approved budget. This is mainly due to the addition of a new position associated with energy market analysis to bolster export sales opportunities with neighboring jurisdictions (Table 3.2.4a, line 2), increased software expenses to forecast generation in the short and medium term, as well as increased costs associated with operational activities.

Corporate Services OM&A

**Variance 1 (Table 3.2.1) Increase of $6.5 million, Line 6, Column 8 (2023/24B vs 2022/23B)**

Corporate OM&A is budgeted at $114.2 million (line 6, column 1) in 2023/24, an increase of $6.5 million (line 6, Column 8) from the 2022/23 NB Power Board approved budget. The primary drivers of the change include:

- A reclassification of prior year expenditures relating to the Mactaquac Life Achievement Project - $8.8 million. This reclassification relates to the analysis associated with various options contemplated during initial stages of the project. The reclassification will occur when an option is approved. This is a reclassification of prior year expenditures and not new spending.
- Costs associated with digital technology (“DT”) have increased $8.0 million. This increase is driven by continued investments in new technologies that support modernizing the grid; implementing new technologies to become more efficient in our processes; and exploiting the capabilities of existing systems and tools including the Microsoft suite of products and web hosting services. Investments in technology such as Microsoft Teams have enabled a sustained reduction in in-province travel for meetings and conferences. The increase in DT cost is also due to higher software licensing fees as many software contracts have an inflation clause thus driving an increase in the annual costs. The overall increase related to software costs is $2.3 million. Computer equipment leasing costs and hardware costs have increased $1.3 million as a result of new hardware requirements to support the secure network infrastructure for critical grid modernization, including conservation voltage regulation and advanced distribution management system (“ADMS”), remote access, and firewall capabilities. To leverage systems and tools such as ADMS and the Microsoft suite of tools, digital technology internal and external resources are

required to provide specialized support to the business to achieve the most value from such investments. The increase in DT resource requirements also includes labour increases due to negotiated union contracts. The total increase in this area is $4.2 million.

- Partial allocation of the $7.5 million continuous improvement credit to Distribution, Transmission and Generation in the 2023/24 budget. In 2022/23 it was budgeted entirely in Corporate Services - $2.6 million
- Increase in labour and benefits costs in other corporate services departments (apart from DT and enterprise security) attributed mainly to negotiated union increases and changes in staffing requirements - $2.3 million
- Increase in enterprise security cost - $1.7 million. Increases in cyber and physical security related costs are increasing in 2023/24 due to operational costs associated with monitoring services aimed at securing transmission and distribution substations and terminals, as well as generation facilities

Partially offsetting these increases is:

- the addition of the placeholder for planned savings resulting from the cost optimization initiative that is currently underway - $20 million

OM&A EXPENSE VARIANCE ANALYSIS

OM&A expense by cost category is outlined below in Table 3.2.2.

**Table 3.2.2**

**NB Power Corporation**
**OM&A Expense**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Labour & benefits | $ 402.5 | $ 399.9 | $ 387.9 | $ 366.9 | $ 354.0 | $ 365.0 | $ 338.3 | $ 14.5 | $ 12.0 | $ 12.8 | $ 26.7 |
| (2) | Material expense | 37.3 | 31.2 | 32.8 | 35.2 | 32.6 | 36.5 | 33.9 | 4.4 | (1.6) | 2.6 | 2.6 |
| (3) | Hired services | 122.9 | 123.7 | 118.0 | 128.4 | 121.6 | 121.1 | 122.1 | 4.9 | 5.7 | 6.8 | (1.0) |
| (4) | Travel | 4.0 | 3.7 | 3.3 | 1.6 | 2.7 | 1.4 | 5.2 | 0.7 | 0.4 | (1.0) | (3.8) |
| (5) | Vehicles | 13.8 | 11.9 | 11.6 | 12.3 | 10.3 | 10.7 | 10.9 | 2.2 | 0.3 | 2.0 | (0.2) |
| (6) | Equipment | 22.5 | 18.9 | 17.9 | 19.4 | 15.4 | 15.7 | 18.7 | 4.6 | 1.0 | 4.0 | (3.0) |
| (7) | Communication | 5.6 | 5.5 | 5.7 | 5.7 | 4.6 | 5.4 | 5.6 | (0.2) | (0.2) | 1.1 | (0.2) |
| (8) | Properties | 1.9 | 1.6 | 2.2 | 1.4 | 1.4 | 1.0 | 1.2 | (0.3) | (0.6) | (0.1) | (0.1) |
| (9) | Insurance & claims | 17.5 | 16.5 | 17.4 | 15.3 | 15.9 | 13.2 | 13.3 | 0.2 | (0.8) | (0.6) | (0.0) |
| (10) | Corporate costs | 29.6 | 27.5 | 29.5 | 23.6 | 30.0 | 26.5 | 30.4 | 0.1 | (2.0) | (6.4) | (3.9) |
| (11) | Bad debt expense | 2.9 | 2.9 | 3.0 | 1.7 | 3.0 | 1.7 | 3.0 | (0.1) | (0.1) | (1.3) | (1.3) |
| (12) | Incentives and Rebates | 25.3 | 12.2 | 12.6 | 7.4 | 9.7 | 1.8 | 10.7 | 12.8 | (0.3) | (2.3) | (8.9) |
| (13) | Internal Services Charged | - | - | - | - | - | - | - | - | - | - | - |
| (14) | Allocation to capital | (90.5) | (122.3) | (106.8) | (83.5) | (82.0) | (94.4) | (87.4) | 16.4 | (15.5) | (1.5) | (7.0) |
| (14.1) | Labour to capital | (37.3) | (50.6) | (44.3) | (37.0) | (35.6) | (35.9) | (36.4) | 7.1 | (6.2) | (1.4) | 0.5 |
| (14.2) | Overtime to capital | (13.9) | (31.6) | (22.9) | (8.3) | (8.4) | (22.2) | (14.5) | $ 9.0 | (8.7) | 0.1 | (7.8) |
| (14.3) | Fleet to capital | (2.5) | (2.6) | (2.7) | (2.3) | (2.8) | (2.0) | (2.8) | $ 0.2 | $ 0.1 | 0.5 | 0.8 |
| (14.4) | Overhead to capital | (36.8) | (37.5) | (36.9) | (35.8) | (35.1) | (34.3) | (33.7) | $ 0.1 | (0.6) | (0.7) | (0.6) |
| (15) | Post-Employment Benefits | 1.1 | 3.6 | 1.7 | 1.9 | 1.3 | 2.1 | 1.2 | (0.6) | 1.9 | 0.6 | 0.9 |
| (16) | **OM&A expense** | $ 596.4 | $ 536.8 | $ 536.8 | $ 537.5 | $ 520.5 | $ 507.7 | $ 507.1 | $ 59.6 | $ (0.1) | $ 17.0 | $ 0.6 |

Note to reader: Financial tables reflect differences due to rounding

LABOUR & BENEFITS (Table 3.2.2, line 1)

Labour and benefits represent the direct and indirect labour expense for all NB Power employees. It includes bargaining and non-bargaining wages, and the employer portion of benefits and statutory remittances (current service costs for pension and retirement allowance, health and dental benefits, Canada Pension Plan, Employment Insurance, WorkSafeNB fees) and overtime costs.

NB Power employees are members of the Province of New Brunswick Public Service Pension Plan ("NBPSPP").

Electric utility operations and capital projects are very labour intensive, and as a result labour costs are a significant component of NB Power's costs. Net of labour charge-outs to capital, labour costs comprise approximately 58 per cent of total OM&A. Workforce planning is a major area of focus for the organization as it looks to complete planned work in the most cost-effective and efficient manner possible.

NB Power's workforce is approximately 91 per cent unionized. The International Brotherhood of Electrical Workers (IBEW) Local 37 is the bargaining agent for the following three collective agreements:

- Nuclear – effective January 1, 2020 to December 31, 2023
- Transmission, Distribution & Customer Service (including Corporate Services) – effective January 1, 2019 to December 31, 2024
- Generation – expired December 31, 2019. Tentative agreement effective January 1, 2020 to December 31, 2023 rejected by the members

Despite two initial rejections, NB Power ratified the Nuclear Collective Agreement in April 2022. A tentative agreement with Generation was also recently rejected with bargaining scheduled to resume in mid-October.

Please refer to Appendix E i. Human Resources - Overview, for more information about NB Power Human Resources.

Labour and benefits are budgeted at $402.5 million (Table 3.2.2, line 1, column 1). Labour and benefits costs include the gross labour and benefits for all employees across the organization. For the preparation of the 2023/24 budget, an assumed increase of 2.0 per cent for non-union employees was included, as was a provision for union increases pending ratification of the respective collective agreements.

Benefit costs, on average for all divisions, represent approximately 21.8 per cent of regular and term labour costs. The benefit rate calculation is a function of the benefit costs for the division (life, dental, health, superannuation, Canada Pension Plan, Employment Insurance, Workers Compensation, and flex benefit costs) divided by the total budgeted salary and wages of the division. Portions of labour and benefits costs are allocated to capital and the amount is included under the allocations to capital cost category (Table 3.2.2, line 14).

Details of the 2023/24 budgeted labour and benefit costs include:

- Salaries and benefits for regular and term employees - $362.1 million (2,742 regular and 254 term at March 31, 2024)
- Casual labour - $4.1 million
- Overtime - $36.2 million
- Labour and overtime charge-out to capital - $51.2 million

Table 3.2.3 Summary of Labour Positions below shows the projected Plan of Establishment ("POE") for the test year compared to the 2022/23 NB Power Board approved budget, and the actual numbers for the two previous years. It includes the breakdown between regular and term positions, and union and non-union. Most of the variances can be attributed to NB Power's focus on support for customers, including the reliability of our critical infrastructure and customer agent support; nuclear regulatory requirements for fatigue management; and special projects associated with changing business requirements and capital planned work. Critically important for the reliability of our infrastructure is our attention to workforce and succession planning which reduces the risks associated with time to talent among our operators and within the line trades. More information regarding workforce and succession planning can be found in Appendix E i. NB Power Human Resources - Overview.[3]

[3] This addresses Minimum Filing Requirements 54 and 55.

Included within the Plan of Establishment are resources required and dedicated to initiatives where funding is provided by a third party. This includes resources required to support the federal low carbon economy fund and the energy efficiency fund. Where funding is received, the accounting treatment is to net out the expense so generally costs associated with these initiatives are not reflected in the OM&A expense component of the revenue requirement.

Please refer to Appendix BD - Continuity Schedule of Regular and Succession Positions, which includes monthly schedules to August 2022.

The total position requirements for the test year are included in Table 3.2.3 (column 1, row 49). This reflects the number of positions required to complete the overall planned work in the test year[4]. Please refer to Appendix F – NB Power Organizational Charts, which includes the Executive and direct reports structure effective August 2022.[5]

For a listing of the new positions included in the 2023/24 budget please refer to Table 3.2.4a Summary of New Positions. The positions identified under the changing business requirements section pertain to new positions identified in the preparation of the 2023/24 budget based on business requirements. The succession positions section identifies the number of succession positions added based upon the time to talent requirements. The existing programs, projects and baseload work section of the table includes those positions included as part of existing work requirements.

The process for adding net new positions involves executive oversight in the budget process followed by a second validation of the need at the time the request to fill the resource is initiated.

When a position is vacated naturally through attrition, it takes time to obtain the appropriate approvals and perform the staffing process to backfill the role, resulting in a relatively consistent vacancy rate in the plan of establishment of approximately 5 per cent.

[4] This addresses Minimum Filing Requirement 56
[5] This addresses Minimum Filing Requirement 20 and 56.

NB Power has included a $3.4 million vacancy credit in fiscal year 2023/24 to recognize the anticipated vacancy rate that naturally occurs as positions remain unfilled for portions of the year with employee retirement, leaves of absence, resignations, and movement within departments. The method used to calculate the variance is based on historical vacancy trends and recognizes that not all position vacancies result in savings as overtime, casual staffing, or hired services may be required to supplement the vacancy(s) in the workforce. Many work situations, such as minimum staff complements and commitments to completing planned work within established timelines, result in incurring additional costs above the budgeted costs of the vacant position.

**Table 3.2.3**
**NB Power Corporation**
**Summary of Positions**
Fiscal Years Ending March 31

| | **Component** | (1) 2023/24B | (2) 2022/23B | (3) 2021/22A | (4) 2020/21A | (5) 2020/21R | (6) Variance 1 (1)-(2) | (7) Positions added in 2023/24B | (8) Positions removed in 2023/24B | (9) Other variances 2023/24B |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Regular positions** | | | | | | | | | |
| | **Non-union** | | | | | | | | | |
| (1) | Transmission | 8 | 8 | 9 | 7 | 9 | - | - | - | - |
| (2) | Nuclear | 42 | 45 | 42 | 45 | 42 | (3) | - | (3) | - |
| (3) | Generation | 20 | 21 | 21 | 22 | 17 | (1) | - | - | (1) |
| (4) | Distribution & Customer Service | 34 | 37 | 39 | 38 | 31 | (3) | | (1) | (2) |
| (5) | Corporate Services | 132 | 130 | 124 | 120 | 124 | 2 | 1 | (5) | 6 |
| (6) | Energy Marketing | 14 | 13 | 13 | 13 | 14 | 1 | 1 | - | - |
| (7) | **Sub-total** | **250** | **254** | **248** | **245** | **237** | **(4)** | **2** | **(9)** | **3** |
| | **Union** | | | | | | | | | |
| (8) | Transmission | 343 | 337 | 321 | 319 | 327 | 6 | 10 | (6) | 2 |
| (9) | Nuclear | 856 | 834 | 870 | 861 | 815 | 22 | - | - | 22 |
| (10) | Generation | 351 | 339 | 343 | 336 | 336 | 12 | 4 | (1) | 9 |
| (11) | Distribution & Customer Service | 517 | 516 | 517 | 512 | 493 | 1 | 9 | - | (8) |
| (12) | Corporate Services | 425 | 406 | 383 | 375 | 361 | 19 | 25 | (14) | 8 |
| (13) | Energy Marketing | - | - | - | - | - | - | - | - | - |
| (14) | **Sub-total** | **2,492** | **2,432** | **2,434** | **2,403** | **2,332** | **60** | **48** | **(21)** | **33** |
| | **Total by Division** | | | | | | | | | |
| (15) | Transmission | 351 | 345 | 330 | 326 | 336 | 6 | 10 | (6) | 2 |
| (16) | Nuclear | 898 | 879 | 912 | 906 | 857 | 19 | - | (3) | 22 |
| (17) | Generation | 371 | 360 | 364 | 358 | 353 | 11 | 4 | (1) | 8 |
| (18) | Distribution & Customer Service | 551 | 553 | 556 | 550 | 524 | (2) | 9 | (1) | (10) |
| (19) | Corporate Services | 557 | 536 | 507 | 495 | 485 | 21 | 26 | (19) | 14 |
| (20) | Energy Marketing | 14 | 13 | 13 | 13 | 14 | 1 | 1 | - | - |
| (21) | **Total regular positions** | **2,742** | **2,686** | **2,682** | **2,648** | **2,569** | **56** | **50** | **(30)** | **36** |
| | **Term positions** | | | | | | | | | |
| | **Non-union** | | | | | | | | | |
| (22) | Transmission | - | - | - | - | - | - | - | - | - |
| (23) | Nuclear | - | 1 | 1 | 1 | - | (1) | - | - | (1) |
| (24) | Generation | - | - | - | - | - | - | - | - | - |
| (25) | Distribution & Customer Service | - | - | - | - | - | - | - | - | - |
| (26) | Corporate Services | - | 1 | - | - | - | (1) | - | (1) | - |
| (27) | Energy Marketing | - | - | - | - | - | - | - | - | - |
| (28) | **Sub-total** | **-** | **2** | **1** | **1** | **-** | **- 2** | **-** | **- 1** | **- 1** |
| | **Union** | | | | | | | | | |
| (29) | Transmission | 34 | 33 | 35 | 14 | 20 | 1 | - | - | 1 |
| (30) | Nuclear | 76 | 53 | 42 | 33 | 23 | 23 | 39 | (2) | (14) |
| (31) | Generation | 2 | 1 | 2 | - | - | 1 | - | - | 1 |
| (32) | Distribution & Customer Service | 111 | 112 | 113 | 72 | 72 | (1) | 1 | (11) | 9 |
| (33) | Corporate Services | 31 | 36 | 44 | 34 | 20 | (5) | - | (12) | 7 |
| (34) | Energy Marketing | - | - | - | - | - | - | - | - | - |
| (35) | **Sub-total** | **254** | **235** | **236** | **153** | **135** | **19** | **40** | **(25)** | **4** |
| | **Total by Division** | | | | | | | | | |
| (36) | Transmission | 34 | 33 | 35 | 14 | 20 | 1 | - | - | 1 |
| (37) | Nuclear | 76 | 54 | 43 | 34 | 23 | 22 | 39 | (2) | (15) |
| (38) | Generation | 2 | 1 | 2 | - | - | 1 | - | - | 1 |
| (39) | Distribution & Customer Service | 111 | 112 | 113 | 72 | 72 | (1) | 1 | (11) | 9 |
| (40) | Corporate Services | 31 | 37 | 44 | 34 | 20 | (6) | - | (13) | 7 |
| (41) | Energy Marketing | - | - | - | - | - | - | - | - | - |
| (42) | **Total term positions** | **254** | **237** | **237** | **154** | **135** | **17** | **40** | **(26)** | **3** |
| | **Regular and term positions** | | | | | | | | | |
| (43) | Transmission | 385 | 378 | 365 | 340 | 356 | 7 | 10 | (6) | 3 |
| (44) | Nuclear | 974 | 933 | 955 | 940 | 880 | 41 | 39 | (5) | 7 |
| (45) | Generation | 373 | 361 | 366 | 358 | 353 | 12 | 4 | (1) | 9 |
| (46) | Distribution & Customer Service | 662 | 665 | 669 | 622 | 596 | (3) | 10 | (12) | (1) |
| (47) | Corporate Services | 588 | 573 | 551 | 529 | 505 | 15 | 26 | (32) | 21 |
| (48) | Energy Marketing | 14 | 13 | 13 | 13 | 14 | 1 | 1 | - | - |
| (49) | **Total regular and term positions** | **2,996** | **2,923** | **2,919** | **2,802** | **2,704** | **73** | **90** | **(56)** | **39** |

**Table 3.2.4a**
**NB Power Corporation**
**Summary of New Positions in 2023/24**

| | | Transmission | Nuclear | Generation | Distribution & Customer Service | Corporate Services | Energy Marketing | **Total** |
|---|---|---|---|---|---|---|---|---|
| **Regular positions** | | | | | | | | |
| (1) | **Changing Business Requirements** | | | | | | | |
| (2) | Natural Gas Trading & Scheduling | | | | | | 1 | 1 |
| (3) | **Succession planning** | | | | | | | |
| (4) | Operator | 1 | | 3 | | | | 4 |
| (5) | Power System Technician | 3 | | | | | | 3 |
| (6) | Digital Technology | | | | | 6 | | 6 |
| (7) | Environment | | | | | 1 | | 1 |
| (8) | Real Estate | | | | | 1 | | 1 |
| (9) | **Existing programs, projects and baseload work** | | | | | | | |
| (10) | Maintenance | | | 1 | | | | 1 |
| (11) | Engineering | 3 | | | 1 | | | 4 |
| (12) | Operator | 3 | | | | | | 3 |
| (13) | Facilities | | | | | 1 | | 1 |
| (14) | Supply Chain & Fleet | | | | | 2 | | 2 |
| (15) | Physical & Cyber Security | | | | | 2 | | 2 |
| (16) | Efficiency Services | | | | 5 | | | 5 |
| (17) | Products & Services | | | | 3 | | | 3 |
| (18) | Corporate Project Management | | | | | 1 | | 1 |
| (19) | Strategic Project Management | | | | | 3 | | 3 |
| (20) | Digital Technology | | | | | 6 | | 6 |
| (21) | Brand & Marketing | | | | | 3 | | 3 |
| **(22)** | **Subtotal, regular positions** | **10** | **0** | **4** | **9** | **26** | **1** | **50** |
| **Term Positions** | | | | | | | | |
| (23) | **Existing programs, projects and baseload work** | | | | | | | |
| (24) | Nuclear Backlog Initiative | | 39 | | | | | 39 |
| (25) | Efficiency Services | | | | 1 | | | 1 |
| **(26)** | **Term Subtotal** | **0** | **39** | **0** | **1** | **0** | **0** | **40** |
| **(27)** | **Total** | **10** | **39** | **4** | **10** | **26** | **1** | **90** |

**Table 3.2.4b**
**NB Power Corporation**
**Summary of Removed Positions in 2023/24**

| | | Transmission | Nuclear | Generation | Distribution & Customer Service | Corporate Services | Energy Marketing | Total |
|---|---|---|---|---|---|---|---|---|
| **Regular positions** | | | | | | | | |
| (1) | **Succession planning** | | | | | | | |
| (2) | Regulatory | | | | | -2 | | -2 |
| (3) | Employee Programs & Services | | | | | -1 | | -1 |
| (4) | Power System Technician | -4 | | | | | | -4 |
| (5) | Operator | | | -1 | | | | -1 |
| (6) | Customer Relations | | | | -1 | | | -1 |
| (7) | Engineering | -1 | | | | | | -1 |
| (8) | Load Forecaster | -1 | | | | | | -1 |
| (9) | **Existing programs, projects and baseload work** | | | | | | | |
| (10) | Engineering | | -1 | | | | | -1 |
| (11) | Maintenance | | -2 | | | | | -2 |
| (12) | Business Development | | | | | -1 | | -1 |
| (13) | Employee Programs & Services | | | | | -1 | | -1 |
| (14) | Products & Services | | | | | -1 | | -1 |
| (15) | Energy Smart Grid | | | | | -1 | | -1 |
| (16) | Finance | | | | | -3 | | -3 |
| (17) | Supply Chain & Fleet | | | | | -1 | | -1 |
| (18) | Regulatory | | | | | -1 | | -1 |
| (19) | Digital Technology | | | | | -5 | | -5 |
| (20) | Correction | | | | | -2 | | -2 |
| **(21)** | **Subtotal, regular positions** | **-6** | **-3** | **-1** | **-1** | **-19** | **0** | **-30** |
| **Term Positions** | | | | | | | | |
| (22) | **Succession planning** | | | | | | | |
| (23) | Power Line Technician Apprentice | | | | -10 | | | -10 |
| (24) | **Existing programs, projects and baseload work** | | | | | | | |
| (25) | Maintenance | | -2 | | | | | -2 |
| (26) | Products & Services | | | | | -2 | | -2 |
| (27) | Energy Smart Grid | | | | | -3 | | -3 |
| (28) | Digital Technology | | | | | -2 | | -2 |
| (29) | Employee Programs & Services | | | | | -3 | | -3 |
| (30) | Finance | | | | | -1 | | -1 |
| (31) | Project Management | | | | | -1 | | -1 |
| (32) | Supply Chain & Fleet | | | | | -1 | | -1 |
| (33) | Provincial Field Operations | | | | -1 | | | -1 |
| **(33)** | **Term Subtotal** | **0** | **-2** | **0** | **-11** | **-13** | **0** | **-26** |
| **(34)** | **Total** | **-6** | **-5** | **-1** | **-12** | **-32** | **0** | **-56** |

**Table 3.2.4c**
**NB Power Corporation**
**Summary of Other Positions in 2023/24**

| | | Transmission | Nuclear | Generation | Distribution & Customer Service | Corporate Services | Energy Marketing | Total |
|---|---|---|---|---|---|---|---|---|
| **Regular positions** | | | | | | | | |
| (1) | **Succession planning** | | | | | | | |
| (2) | Energy Smart Grid | | | | | 1 | | 1 |
| (3) | Employee Programs & Services | | | | | 1 | | 1 |
| (4) | Systems & Telecommunication | | | | | 1 | | 1 |
| (5) | Operator | 1 | | | 1 | | | 2 |
| (6) | Engineering | 1 | | | 1 | | | 2 |
| (7) | IT Specialist | 1 | | | | | | 1 |
| (8) | Power Line Technician Apprentice | | | | 1 | | | 1 |
| (9) | **Existing programs, projects and baseload work** | | | | | | | |
| (10) | Emergency Services | | 15 | | | | | 15 |
| (11) | Engineering | | 6 | 4 | | | | 10 |
| (12) | Chemistry | | 1 | | | | | 1 |
| (13) | Legal | | | | | 1 | | 1 |
| (14) | Chief Customer Officer | | | | | 1 | | 1 |
| (15) | Health and Wellness | | | | | 1 | | 1 |
| (16) | Business Development | | | | | 1 | | 1 |
| (17) | Supply Chain and Fleet | | | | | -1 | | -1 |
| (18) | First Nations | | | | | -1 | | -1 |
| (19) | Energy Smart Grid | | | | | -1 | | -1 |
| (20) | Physical & Cyber Security | | | | | 1 | | 1 |
| (21) | Operator | | | 1 | | | | 1 |
| (22) | Maintenance | | | 2 | | | | 2 |
| (23) | Efficiency Services | | | | 2 | | | 2 |
| (24) | Customer Relations | | | | -8 | | | -8 |
| (25) | Provincial Field Operations | | | | -1 | | | -1 |
| (26) | Attrition credit removal | | | 3 | 1 | | | 4 |
| (27) | Corrections | | | | -2 | 1 | | -1 |
| (28) | Net Transfers | -1 | | -2 | -5 | 8 | | 0 |
| **(29)** | **Subtotal, regular positions** | **2** | **22** | **8** | **-10** | **14** | **0** | **36** |
| **Term Positions** | | | | | | | | |
| (30) | **Succession planning** | | | | | | | |
| (31) | Provincial Field Operations | | | | 1 | | | 1 |
| (31) | Power Line Technician Apprentice | | | | 1 | | | 1 |
| (32) | **Existing programs, projects and baseload work** | | | | | | | 0 |
| (32) | Emergency Services | | -15 | | | | | -15 |
| (33) | Mactaquac Life Extension | | | | | 1 | | 1 |
| (33) | Supply Chain and Fleet | | | | | 3 | | 3 |
| (34) | First Nations | | | | | 1 | | 1 |
| (34) | Energy Smart Grid | | | | | 1 | | 1 |
| (35) | Health and Safety | | | | | 1 | | 1 |
| (36) | Maintenance | 1 | | 1 | | | | 2 |
| (37) | Customer Relations | | | | 7 | | | 7 |
| **(38)** | **Term Subtotal** | **1** | **-15** | **1** | **9** | **7** | **0** | **3** |
| **(39)** | **Total** | **3** | **7** | **9** | **-1** | **21** | **0** | **39** |

Table 3.2.3 Summary of Positions outlines the number of positions at the end of each fiscal year as noted in column 1 to column 5. Column 6 in the table shows the variances in positions between the two budget versions, 2023/24B compared to 2022/23B. Columns 7 to 9 show the breakdown of the values in column 6 (the variance column between the two budgeted years). Column 7 includes the new positions added during the budgeting cycle for fiscal year 2023/24, each of which has a completed labour budget request justification. Further information on the new positions can be found in Table 3.2.4a. Column 8 includes

the positions that have been removed since the 2022/23 budget was approved. Further information on the removed positions can be found in Table 3.2.4b. Column 9 includes those positions that were added after the 2022/23 budget was approved and before the planning started for 2023/24. It also includes movements between divisions or categories. Further information can be found in Table 3.2.4c.

**Variance 1 (Table 3.2.2) Increase of $14.5 million - Line 1, Column 8 (2023/24B vs 2022/23B)**

Labour and benefits costs are budgeted to be $402.5 million (line 1, column 1) in the 2023/24 budget, an increase of $14.5 million (line 1, Column 8) from the 2022/23 NB Power Board approved budget. The major reasons for the variance are:

- $23.8 million increase in regular and term salaries and associated benefits is primarily due to
  - budgeted union increases and non-union general increases
  - merit increases for employees not currently at the top of established pay bands
  - an increase in the number of positions resulting from changes in existing programs, projects, and baseload work such as within Efficiency Services and Digital Technology; resources required to support the PLNGS strategic backlog reduction initiative; and succession planning for long lead time to talent positions
  - an increase in benefit expense due in part to the increase in positions and the employer portion of statutory remittances

partially offset by

- $0.8 million decrease in casual salaries and associated benefits mainly due to the planned decrease in PLNGS Operations training support
- $8.5 million decrease in overtime costs primarily related to the PLNGS outage (reduction in outage duration and scope planned in 2023/24 compared to 2022/23).

<u>MATERIAL (Table 3.2.2 line 2)</u>

Material expense is budgeted at $37.3 million in 2023/24. Material expense relates to a variety of items that are used in day-to-day operations for planned and unplanned NB Power work and third-party work (recovered in miscellaneous revenue).

Examples of these costs include:

- On-going plant maintenance material requirements (e.g., conveyor and pulverizer materials, chemicals, fuel handling equipment, pumps, and motors replacements)
- Material for maintenance crews (e.g., transmission crews, high voltage and low voltage mechanics, distribution crews, street light maintenance, meter shop)
- Other miscellaneous supplies such as arc-rated clothing, stationary supplies
- Material delivery costs

**Variance 1 (Table 3.2.2) Increase of $4.4 million, Line 2, Column 8 (2023/24B vs 2022/23B)**

Material costs are budgeted to be $37.3 million (line 2, column 1) in the 2023/24 budget, an increase of $4.4 million (line 2, Column 8) from the 2022/23 NB Power Board approved budget. The increase is related to adjustment of budgets to incorporate the impact of rising prices due to inflation, alignment with actual historical spend trends, critical backlog reduction initiative work, and hydro-related work including Alkali Aggregate Reaction water proofing.

HIRED SERVICES (Table 3.2.2, line 3)

Hired services is the second largest component of OM&A and is budgeted to be $122.9 million in 2023/24. Hired services are used to supplement NB Power's regular workforce. Services are contracted to provide and support specialized or highly technical services, provide outage support, non-routine/one-time work requirements, meet seasonal and peak period work requirements, and to provide flexibility in the workforce. The hired services expense is comprised of numerous contracts to support ongoing activities. In order to ensure competitive pricing, NB Power adheres to the requirements set out in the *Procurement Act* and the *Crown Construction Contracts Act*.

The largest areas of budgeted spending include:

- Construction and maintenance including nuclear specific expertise and line maintenance - $19.9 million
- Specialized engineering and technical services support – $18.9 million
- National Maintenance Agreement (“NMA”) for plant maintenance support - $13.7 million
- Digital technology - $13.1 million
- Project management - $11.7 million
- Facilities management including janitorial, security, lawn maintenance and snow removal - $6.5 million
- Vegetation management - $5.4 million
- CANDU Owners Group (“COG”) (nuclear industry support) - $4.2 million
- Support for demand side management programs - $3.8 million
- Storm contingency - $3.8 million
- Handling of calls in the customer interaction center, payment of overdue accounts, and meter reading - $3.3 million

One item to note in the hired services budget for 2023/24 is the inclusion of a reclassification of prior year expenditures relating to the Mactaquac Life Achievement project - $8.8 million. Please refer to the Corporate Services section above for further explanation.

A continuous improvement credit of $27.5 million is recorded as a placeholder in hired services, $20 million relating to the cost optimization initiative and $7.5 million relating to continuous improvement savings. The 2022/23 budget included a similar continuous improvement credit of $7.5 million.

**Variance 1 (Table 3.2.2) Increase of $4.9 million, Line 3, Column 8 (2023/24B vs 2022/23B)**

Hired services is budgeted to be $122.9 million (line 3, column 1) in 2023/24, an increase of $4.9 million (line 3, Column 8) from the 2022/23 NB Power Board approved budget. The increase is primarily related to:

- Reclassification of prior year expenditures relating to the Mactaquac Life Achievement project - $8.8 million
- Increase in requirements at PLNGS including engineering and specialized nuclear support ($4.2 million), additional maintenance work given the shorter planned outage in 2023/24 ($1.2 million), and backlog reduction initiative ($0.9 million), totalling $6.3 million
- Hydro initiatives and maintenance including waterproofing, grouting & supernatant water disposal - $3.6 million
- Increase in demand side management work - $2.3 million
- Digital technology hired services required to support new and existing systems and tools - $1.8 million
- Increase in spending to improve and support the customer interaction experience and cost increases related to the water heater program - $1.6 million
- Increase in enterprise security - $1.4 million

partially offset by

- Planned savings from the cost optimization initiative - $20 million
- Reduction in storm contingency - $3.7 million
- One-time reduction in vegetation management - $2.2 million

Inflationary pressures are causing cost increases in hired services as many services contracts contain a CPI escalation clause. It is difficult to quantify the incremental impact from the 2022/23 budget to the 2023/24 budget due to changes in planned work and reductions in work plans in the 2023/24 budget to aid in managing the financial impact of inflationary cost pressures.

TRAVEL (Table 3.2.2, line 4)

Travel expense relates to all non-fleet expenses incurred by employees while traveling for NB Power business.  Travel expense includes both in-province and out-of-province travel such as lodging and meals, mileage and non-fleet gas for rentals,, travel allowances for unionized employees, and air travel. With the introduction of remote meeting tools, including Microsoft Teams, NB Power utilizes the tools to reduce the requirement to travel whenever it is feasible to do so. An example of this is the quarterly internal leadership meetings, formally held in-person in Fredericton, are now held via Microsoft Teams, eliminating the need for travel and other associated expenditures including accommodations and meals. Travel expense is budgeted at below pre-pandemic levels.

Travel expense is driven by activities such as:

- Attendance at NB Power related meetings, workshops, and training
- In-province travel related to storm response or other operational support across the divisions
- Participation in external training, committees, and conferences (e.g., CANDU Owners Group (COG), Electricity Canada (formally Canadian Electricity Association (CEA)), Northeast Power Coordinating Council (NPCC), World Association of Nuclear Operators (WANO), Emergency Measures Organization (EMO)

**Variance 1 (Table 3.2.2) increase of $0.7 million, Line 4, Column 8 (2023/24B vs 2022/23B)**

Travel is budgeted at $4.0 million (line 4, column 1) in 2023/24, an increase of $0.7 million (line 4, Column 8) from the 2022/23 NB Power Board approved budget, recognizing an increase in out-of-province travel for such things as meetings and conferences, as many in-person training sessions, conferences, and meetings are resuming. The post Covid spending still represents a significant reduction from previously approved budgets pre Covid.

<u>VEHICLES (Table 3.2.2, line 5)</u>

Vehicles expense relates to ongoing fuel, maintenance and miscellaneous expenses associated with NB Power's fleet of vehicles and short-term vehicle leases. NB Power operates a diverse fleet of over 1,000 vehicles consisting of passenger cars and trucks, large vehicles (fire trucks, digger derricks, line trucks), trailers, and off-road equipment (e.g., all-terrain vehicles, snowmobiles), all of which are utilized as part of the day-to-day operations of NB Power.

The majority of NB Power's vehicles are utilized by the Distribution and Transmission divisions in ensuring the reliability of the distribution and transmission power systems for the benefit of customers. Other vehicles are used primarily at generating stations.

All vehicles are purchased in compliance with the *Procurement Act* and vehicle replacements are based on overall condition assessment which includes a review of the age of vehicle, number of kilometers and maintenance costs.

Details of these costs include:

- Fuel, maintenance and repairs, inspections, vehicle registration fees, and tires for NB Power owned vehicles - $12.5 million
- Short term rentals and fuel- $1.2 million
- Miscellaneous supplies (e.g. windshield wiper fluid, fire extinguishers, light bulbs) - $0.03 million

**Variance 1 (Table 3.2.2) increase of $2.2 million, Line 5, Column 8 (2023/24B vs 2022/23B)**

Vehicle expenses are budgeted at $13.8 million (line 5, column 1) in 2023/24, an increase of $2.2 million (line 5, Column 8) from the 2022/23 NB Power Board approved budget. The increase is related primarily to the inflationary pressure of operating and maintaining the NB Power fleet, including fuel expense and maintenance. Maintenance cost increases are also due to the deferral of replacing the aging fleet. Part of the $18.5 million OM&A budget reductions covered in the OM&A Overview section included a $0.5 million reduction to the vehicle budget. Recognizing the significant inflationary pressure on this cost category, management has committed to undertake every opportunity to effectively manage the fleet budget, looking at alternative and different ways to do work for example.

<u>EQUIPMENT (Table 3.2.2, line 6)</u>

Equipment expense is related to software maintenance agreements, leasing of computer equipment, and small tools and equipment required to perform work. NB Power leases the majority of the organization's computer equipment, which is refreshed on a cyclical basis depending on the computer component type. NB Power also utilizes numerous third-party software applications for which there is an on-going annual licensing or maintenance agreement attached to the software.

The most significant equipment costs are related to leasing and software. Details of these costs include:

- Software licensing and maintenance agreements across the organization (e.g. SAP, Oracle, Cascade, Stakeout, Itron, OSIsoft, etc.)
- Leasing of computer equipment (e.g. laptops, desktops, workstations, toughbooks, etc.)
- Various components of office equipment (e.g. mobile devices, monitors, printers, docking stations)
- Various individual tools and equipment that cost less than $5,000 each

**Variance 1 (Table 3.2.2) Increase of $4.6 million, Line 6, Column 8 (2023/24B vs 2022/23B)**

Equipment expenses are budgeted at $22.5 million (line 6, column 1) in 2023/24, an increase of $4.6 million (line 6, Column 8) from the 2022/23 NB Power Board approved budget. Many software contracts have an inflation clause, thus driving an increase in the annual costs. Software costs are also increasing as the utility seeks to leverage technology including the Microsoft suite of products and web hosting services, with some offsets in travel expense. Computer equipment leasing costs are increasing as a result of new hardware requirements to support the secure network infrastructure for critical grid modernization, including conservation voltage regulation and advanced distribution management system (“ADMS”), remote access, and firewall capabilities.

<u>COMMUNICATIONS (Table 3.2.2, line 7)</u>

Communications expense includes:

- Postage costs which are largely due to the issuance of customer bills and notices. NB Power consistently attempts to mitigate some of this cost by encouraging customers to move to paperless billing

- Telephone costs which are related to the cost for mobile devices (e.g. smart devices, cell phones, turbo sticks, wireless modems for Toughbooks)
- Data communications costs which includes the cost of data services (e.g. wide area network circuits, mobile radios)

**Variance 1 (Table 3.2.2) Decrease of $0.2 million, Line 7, Column 8 (2023/24B vs 2022/23B)**

Communication expenses are budgeted at $5.6 million (line 7, column 1) in 2023/24, a decrease of $0.2 million (line 7, Column 8) from the 2022/23 NB Power Board approved budget. The decrease is related to planned savings from continued promotion and uptake of paperless billing.

PROPERTIES (Table 3.2.2, line 8)

Properties expense includes:

- Non electricity-based heat expense associated with NB Power facilities
- Rental costs for external facilities used for storage, trailers, crane rentals
- Water and sewer expense related to all NB Power and rented facilities

**Variance 1 (Table 3.2.2) Decrease of $0.3 million, Line 8, Column 8 (2023/24B vs 2022/23B)**

Properties expense is budgeted at $1.9 million (line 8, column 1) in 2023/24, a decrease of $0.3 million compared to the 2022/23 NB Power Board approved budget, mainly due to the alignment of the 2023/24 budget with actual expenditures.

INSURANCE & CLAIMS (Table 3.2.2, line 9)

Insurance and claims represent costs for a comprehensive insurance program for NB Power's facilities and operations. Policies include coverage for nuclear, vehicle, general liability, director and officers, all risk and blanket crime insurance premiums, as well as water heater and other miscellaneous damage claim expenses. The policies include first party coverage which protects NB Power's assets and third-party liability insurance which provides protection for operations if NB Power impacts third party property or business. Property policies include fire protection and machinery breakdown coverage for major assets.

**Variance 1 (Table 3.2.2) Increase of $0.2 million, Line 9, Column 8 (2023/24B vs 2022/23B)**

Insurance and claims costs are budgeted at $17.5 million (line 9, column 1) in 2023/24, an increase of $0.2 million (line 9, Column 8) from the 2022/23 NB Power Board approved budget. The higher cost is related to an increase in Nuclear insurance partially offset by a reduction in all risk property insurance.

<u>CORPORATE COSTS (Table 3.2.2, line 10)</u>

Corporate costs include:

- Corporate dues and memberships. NB Power has numerous certified employees across the organization who must maintain their professional certifications. Additionally, employees represent NB Power in a number of external industry associations to which annual memberships apply
- Regulatory assessments related to direct and common costs for the Energy and Utilities Board, Office of the Public Intervener, and Canadian Nuclear Safety Commission ("CNSC") fees
- Environmental fees associated with various environmental testing and monitoring of air, water, land and equipment
- Training fees associated with staff and the development of technical, management and soft skills. Training includes in-house offerings and off-site training
- Grants, bursaries and scholarships in support of various events or activities
- Other corporate business expenses

**Variance 1 (Table 3.2.2) an increase of $0.1 million, Line 10, Column 8 (2023/24B vs 2022/23B)**

Corporate costs are budgeted at $29.6 million (line 10, column 1) in 2023/24, an increase of $0.1 million (line 10, Column 8) from the 2022/23 NB Power Board approved budget mainly due to increased training at PLNGS relating to initiative work and maintenance requirements.

BAD DEBT EXPENSE (Table 3.2.2, line 11)

Bad debt expense relates to write-offs of customer accounts, net of the recovery of amounts previously written off and adjustments to the allowance for doubtful accounts, a provision for accounts in arrears which may be written off in the future. NB Power has an internal collections process that is triggered after the first time a customer goes into arrears. This process includes the issuance of reminder letters, agent calls, the creation of payment plans, and potentially (as a last resort) disconnection of service. A third-party collection agency is also used. After efforts have proven unsuccessful, NB Power writes-off, on a monthly basis, accounts that are deemed uncollectible from:

- bankruptcies
- deceased customers
- inactive accounts where the aged receivables are greater than 365 days in arrears

**Variance 1 (Table 3.2.2) a decrease of $0.1 million, Line 11, Column 8 (2023/24B vs 2022/23B)**

Bad debt expense is budgeted at $2.9 million (line 11, column 1) in 2023/24, a decrease of $0.1 million (line 11, Column 8) from the 2022/23 NB Power Board approved budget.

INCENTIVES AND REBATES (Table 3.2.2, line 12)

Incentives and rebates represent costs associated with reducing the barriers to customer participation in energy efficiency programs. One of the largest barriers is the upfront cost for customers to make investments in energy efficiency upgrades. Energy efficiency programs provide a range of financial and other incentives to encourage investments in energy-efficient technologies and products, related services, and/or behaviour change. These incentives range from simple cash rebates for the purchase of efficient products, to bundled customization of financial incentives and technical assistance. Various program incentives and rebates are offered to residential, commercial and industrial customers.

**Variance 1 (Table 3.2.2) Increase of $12.8 million, Line 12, Column 8 (2023/24B vs 2022/23B)**

Incentives and rebates are budgeted at $25.3 million (line 12, column 1) in 2023/24, an increase of $12.8 million (line 12, Column 8) from the 2022/23 NB Power Board approved budget. This is a significant increase in spending as a result of legislative changes that require NB Power to achieve specific energy reduction targets each year as set out in the regulation. The increased spending is offset through the DSM regulatory deferral (see Table 3.6.6 Net Change in Regulatory Balance – Energy Efficiency and Demand Response Deferral).

INTERNAL SERVICES CHARGED (Table 3.2.2, line 13)

**Variance 1 (Table 3.2.2) No change - Line 13, Column 8 (2023/24B vs 2022/23B)**

Internal services charged is nil (line 13, column 1) in 2023/24B, consistent (line 13, column 3) with 2022/23B.

ALLOCATIONS TO CAPITAL (Table 3.2.2, line 14)

Allocations to capital relate to OM&A expenses charged to capital in support of capital work. They include labour directly attributable to capital projects, as well as vehicle and overhead allocations. Allocations to capital result in an increase in capital project costs and a reduction in OM&A costs.

Labour to capital (Table 3.2.2, line 14.1) and overtime to capital (Table 3.2.2, line 14.2) allocations are estimates by each division of the amount of internal labour that is needed to execute capital projects and will vary based on the capital projects planned in the year. This includes annual labour to capital and overtime to capital associated with planned plant outages depending on the nature and scope of said outages.

Overhead costs (Table 3.2.2, line 14.4) are incremental in nature. These overhead costs would not exist if NB Power did not construct its own fixed assets. Overhead costs that are capitalized include such costs as salaries and benefits of operational and engineering personnel not directly chargeable to projects, and the cost of administrative services provided by various departments which are required to support capital projects. The overhead rate is applied to the total monthly project cost, calculated on the capital expenditures during the month.

An update of the overhead rates was last completed in fiscal year 2017/18 by NB Power staff utilizing the methodology previously developed by KPMG. Overhead rates capitalize a predetermined dollar amount of support costs for regular capital work and therefore the rates will be reset annually based on the divisional capital budgets. Major capital project overhead rates are developed on a project-by-project basis.

The overhead rates include the following components:

- An appropriate share of the “non-productive time” (e.g. vacation, sick time and statutory holidays) of personnel charging directly to projects
- Support and infrastructure costs associated both with personnel charging directly to projects and with personnel associated with overhead activities

When vehicles are used to support capital projects, an associated cost is applied to those capital projects and credited to OM&A.

**Variance 1 (Table 3.2.2) Decrease of $16.4 million, Line 14, Column 8 (2023/24B vs 2022/23B)**

Allocations to capital is budgeted at $90.5 million in 2023/24 (Table 3.2.2, line 14, column 1), a decrease of $16.4 million (Table 3.2.2, line 14, Column 8) from the 2022/23 NB Power Board approved budget. The decrease is due to a lower charge-out of labour, overtime and fleet to capital in 2023/24. A significant contributing factor to the decrease is a shorter PLNGS major outage and inspection project in 2023/24 compared to 2022/23. This is part of the natural cycle of outage work in that there will always be year-over-year differences resulting from changes in planned outage work and duration. Partially offsetting the reduction is an increase in labour charge-out to capital resulting from staff optimization whereby regular and term positions are replacing hired services costs in capital.

POST-EMPLOYMENT BENEFITS (Table 3.2.2, line 15)

Post-Employment Benefits include costs related to NB Power's previous early retirement program. NB Power has occasionally offered early retirement incentive programs to employees. The last such program was offered in 2010. The present value of the estimated future costs of the early retirement programs is charged to earnings in the year that the program is accepted by employees.

**Variance 1 (Table 3.2.2) Decrease of $0.6 million, Line 15, Column 8 (2023/24B vs 2022/23B)**

Post-Employment Benefits is budgeted at $1.1 million (line 15, column 1) in 2023/24, a decrease of $0.6 million (line 15, Column 8) from the 2022/23 NB Power Board approved budget. The 2022/23 NB Power Board approved budget had a onetime charge regarding PLNGS retirement allowance expenditures.

## OM&A COST PER MWH DELIVERED AND OM&A COST PER CUSTOMER

Table 3.2.5 provides the total OM&A cost per MWh delivered and the total OM&A cost per customer[6].

**Table 3.2.5**

**NB Power Corporation**
**Total OM&A costs per MWh and per Customer**
Fiscal Years Ending March 31

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | OM&A (in millions $) | $ 596.4 | $ 536.8 | $ 536.8 | $ 537.5 | $ 520.5 | $ 507.7 | $ 507.1 | $ 59.6 | $ (0.1) | $ 17.0 | $ 0.6 |
| (2) | MWh Delivered (in thousands) | 19,202 | 20,912 | 17,379 | 20,897 | 16,546 | 18,742 | 16,942 | 1,823 | 3,533 | 4,350 | 1,801 |
| (3) | # of Customers | 418,636 | 416,212 | 413,614 | 415,922 | 411,795 | 409,701 | 382,488 | 5,022 | 2,597 | 4,127 | 27,213 |
| (4) | OM&A Costs / MWh Delivered | $ 31.06 | $ 25.67 | $ 30.89 | $ 25.72 | $ 31.46 | $ 27.09 | $ 29.93 | $ 0.17 | $ (5.22) | $ (5.74) | $ (2.84) |
| (5) | OM&A Costs / Customer | $ 1,424.64 | $ 1,289.62 | $ 1,297.88 | $ 1,292.26 | $ 1,264.01 | $ 1,239.11 | $ 1,325.74 | $ 126.77 | $ (8.25) | $ 28.25 | $ (86.63) |

Note to reader: Financial tables reflect differences due to rounding

## OM&A Costs per MWh Delivered

**Variance 1 (Table 3.2.5) Increase OM&A Cost $0.17 per MWh Delivered, Line 4, Column 8 (2023/24B vs 2022/23B)**

OM&A Costs/MWh Delivered is $31.06 (line 4, column 1) in the 2023/24 budget, a net increase of $0.17 (line 4, Column 8) from the 2022/23 NB Power Board approved budget. The increase is due to an increase in the OM&A budget of $59.6 million partially offset by an increase in in-province and out-of-province MWh Delivered (in thousands) in 2023/24 of 1,823 GWh.

[6] This addresses Minimum Filing Requirement 47.

OM&A Costs per Customer

**Variance 1 (Table 3.2.5) Increase of $126.77 per Customer, Line 5, Column 8 (2023/24B vs 2022/23B)**

OM&A Costs per Customer are $1,424.64 (line 5, column 1) in the 2023/24 budget, a net increase of $126.77 per customer (line 5, Column 8) from the 2022/23 NB Power Board approved budget. The increase is due to an increase in the OM&A budget of $59.6 million partially offset by an increase in the number of customers in 2023/24 of 5,022.

**OM&A INITIATIVES & PROGRAMS**

New OM&A initiatives and programs are identified during the creation and continual update of budgets and forecasts. One-time or short-term investments to achieve targets are brought forward for evaluation and prioritization and selected initiatives are included in the revenue requirement. Often the funding and resources required to implement smaller value initiatives and program improvement is absorbed within the existing base load work and incremental resources and funding are not required. In other cases, the funding is incremental in nature. This could involve capital spending or if the spending does not qualify as a capital expenditure it is recorded as an OM&A initiative[7]. There are several OM&A initiatives over $1 million included in the 2023/24 budget.

For information regarding the OM&A expense of the individual OM&A initiatives please refer to Table 3.2.6. The spending includes labour expense where resources are hired specifically to work on the initiative, such as the PLNGS priority backlog initiative and demand side management. If the work is being completed with the assistance of existing staff members partially assigned to the initiative, the spending excludes this type of expensen, as the resource is budgeted elsewhere to complete baseload work and the expense is not incremental in nature.

[7] This addresses Minimum Filing Requirements 43 and 44.

Table 3.2.6 outlines individual OM&A initiatives and programs costing more than $1 million in the 2023/24 budget. The initiatives include those that are ongoing or multi-year as previously reported, including PLNGS improvement initiatives and the demand side management program. Some costs that were previously reported in this table, including vegetation management, enterprise cyber security and alkali aggregate reaction ("AAR"), are now considered base load work and as such have been removed.

**Table 3.2.6**

**NB Power Corporation**
**Initiatives greater than $1 million in OM&A Expense**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | PLNGS Priority Backlog Reduction | $ 6.2 | $ 3.1 | $ - | $ - | $ - | $ - | $ - | $ 6.2 | $ 3.1 | $ - | $ - |
| (2) | PLNGS Obsolescence Management Program | 1.1 | 1.0 | 1.0 | 1.4 | 1.0 | 1.7 | 1.0 | 0.0 | (0.0) | 0.4 | 0.7 |
| (3) | PLNGS Fuel Channel | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.5 | - | - | - | (0.5) |
| (4) | PLNGS Lifecycle Management | 1.1 | 1.0 | 0.9 | 0.9 | 0.9 | 0.5 | 0.8 | 0.2 | 0.1 | 0.0 | (0.2) |
| (5) | PLNGS Improvement Initiatives | 2.4 | 1.8 | 2.3 | 2.4 | 2.8 | 2.1 | 3.6 | 0.0 | (0.5) | (0.4) | (1.5) |
| (6) | Generation Maintenance Backlog Reduction | 1.8 | 1.4 | 1.4 | 0.0 | 1.0 | - | - | 0.4 | (0.0) | (1.0) | - |
| (7) | Hydro - Grouting blitz & supernatant water disposal | 1.8 | - | - | - | - | - | - | 1.8 | - | - | - |
| (8) | Demand Side Management | 33.2 | 17.1 | 17.1 | 11.7 | 14.8 | 6.3 | 17.0 | 16.1 | 0.0 | (3.1) | (10.7) |
| (9) | AMI | 3.9 | 2.2 | 4.1 | 1.8 | 2.5 | 1.1 | 2.4 | (0.2) | (1.9) | (0.6) | (1.3) |
| (10) | ERP System Upgrade | 2.0 | 1.5 | 1.9 | 0.4 | 3.0 | 0.4 | - | 0.1 | (0.4) | (2.6) | 0.4 |
| (11) | **Total** | $ 55.4 | $ 31.1 | $ 30.8 | $ 20.7 | $ 28.1 | $ 14.1 | $ 27.3 | $ 24.6 | $ 0.2 | (7.3) | (13.2) |

Note to reader: Financial tables reflect differences due to rounding.

PLNGS PRIORITY BACKLOG REDUCTION (Table 3.2.6, line 1)

PLNGS Priority Backlog Reduction is intended to address one of PLNGS' most important gaps to industry excellence and top decile performance. This initiative will help ensure the right work gets done at the right time to lower our preventable risks to safety and generation, and to drive overall performance. Key performance indicators and strategic measures that top performing nuclear stations focus upon within their Work Management processes include Priority Backlog and maintaining the total backlog at low levels. As discussed in the OM&A Overview, as part of the cost management exercise completed in preparing the 2023/24 budget, the backlog reduction initiative was one area where management evaluated the submitted planned work and associated spending and based on a risk-based approach decided to scale back the planned work in half and spread the initiative over a longer timeframe. This was evaluated also from an impact to the customer perspective in terms of achieving the most value for the customer and managing the impact to the customer within the planned revenue requirement.

**Variance 1 (Table 3.2.6) Increase of $6.2 million, Line 1, Column 8 (2023/24B vs 2022/23B)**

PLNGS Priority Backlog Reduction is budgeted at $6.2 million (line 1, column 1) in the 2023/24 budget, an increase of $6.2 million from the 2022/23 NB Power Board approved budget. The addition of this initiative is to address resource requirements to enhance the station's reliability and sustainability over a four year period commencing in fiscal year 2022/23.

PLNGS OBSOLESCENCE MANAGEMENT PROGRAM (Table 3.2.6, line 2)

PLNGS Obsolescence Management Program is a way to identify, prioritize and solve equipment obsolescence issues proactively. PLNGS has implemented this program by collaborating with industry peers and adopting industry best practices.

**Variance 1 (Table 3.2.6) No change, Line 2, Column 8 (2023/24B vs 2022/23B)**

PLNGS Obsolescence Management Program is budgeted at $1.1 million (line 2, column 1) in the 2023/24 budget, no change from the 2022/23 NB Power Board approved budget.

PLNGS FUEL CHANNEL (Table 3.2.6, line 3)

PLNGS Fuel Channel initiative is required to ensure continued fitness for service and to assess the potential for plant life extension. This initiative has been progressing over a four year period with the collaboration of CANDU Owners Group (COG) and will be completed in the test year.

**Variance 1 (Table 3.2.6) No Change, Line 3, Column 8 (2023/24B vs 2022/23B)**

PLNGS Fuel Channel initiative is budgeted at $2.0 million (line 3, column 1) in the 2023/24 budget, no change from the 2022/23 NB Power Board approved budget.

PLNGS LIFECYCLE MANAGEMENT (Table 3.2.6, line 4)

PLNGS Lifecycle Management involves developing the processes, procedures, and lifecycle management plans to support the reliable operation of the station to the planned end-of-life while considering safety and economic viability. The initiative is aimed at improving PLNGS asset management, developing the capital portfolio and establishing the end-of-life strategy for the station.

**Variance 1 (Table 3.2.6) Increase $0.2 million, Line 4, Column 8 (2023/24B vs 2022/23B)**

PLNGS Lifecycle Management is budgeted at $1.1 million (line 4, column 1) in the 2023/24 budget, an increase of $0.2 million from the 2022/23 NB Power Board approved budget. The increase is primarily due to the station's focus to accelerate completion of lifecycle management plans in order to increase equipment reliability.

PLNGS IMPROVEMENT INITIATIVES (Table 3.2.6, line 5)

PLNGS Improvement Initiatives align PLNGS programs with regulatory requirements and certified staffing in accordance with nuclear standards. These are a compilation of initiatives currently progressing, that on an individual basis are less than $1 million. In the test year, the initiatives consist of:

- CSA N285.7 Periodic Inspections

- Digital Transformation
- CSA N286.7 Software Quality Assurance
- Fire Testing Optimization
- Control Room Operator in Training Pilot Program

**Variance 1 (Table 3.2.6) No change, Line 5, Column 8 (2023/24B vs 2022/23B)**

PLNGS Improvement Initiatives is budgeted at $2.4 million (line 5, column 1) in 2023/24, no change from the 2022/23 NB Power Board approved budget.

GENERATION MAINTENANCE BACKLOG REDUCTION (Table 3.2.6, line 6)

Generation Maintenance Backlog Reduction initiative is to address an increasing backlog of maintenance work orders at the Belledune Generating Station and the Coleson Cove Generating Station. The purpose is to reduce this backlog to maintain station reliability at high levels, improve system availability, and reduce operator burden.

**Variance 1 (Table 3.2.6) Increase $0.4 million, Line 6, Column 8 (2023/24B vs 2022/23B)**

Generation Maintenance Backlog Reduction is budgeted at $1.8 million (line 6, column 1) in the 2023/24 budget, an increase of $0.4 million from the 2022/23 NB Power Board approved budget. This increase is primarily due to adding funds for backlog reduction at Coleson Cove Generating Station.

Hydro GROUTING BLITZ & SUPERNATANT WATER DISPOSAL (Table 3.2.6, line 7)

Hydro – Grouting blitz & supernatant water disposal initiative will allow the critical drilling and grouting operations at Mactaquac to resume by providing the funds to cover these activities and the proper treatment and disposal of the generated effluent. This allows the Mactaquac Generating Station to test treatment systems while ultimately disposing of water at regulated waste management facilities and adding strength back to the concrete structures.

**Variance 1 (Table 3.2.6) Increase $1.8 million, Line 7, Column 8 (2023/24B vs 2022/23B)**

Hydro – Grouting blitz & supernatant water disposal Initiative is budgeted at $1.8 million (line 7, column 1) in the 2023/24 budget, an increase of $1.8 million from the 2022/23 NB Power Board approved budget. Incremental spending is required to support AAR work related to grouting. Additional funds are also required as a result of Environment and Climate Change Canada warning where grouting and drilling supernatant water can no longer be treated and discharged to the river with existing equipment. The utility is now required to pay for the environmentally safe disposal of the supernatant water.

DEMAND SIDE MANAGEMENT (Table 3.2.6, line 8)

Demand Side Management (DSM) is a strategy used by electric utilities to control demand by encouraging consumers to modify their level and pattern of electricity usage. NB Power offers a suite of energy efficiency programs to its customers as well as a demand response program. The primary goal of these programs is to promote the efficient use of energy in our customers' homes and businesses. They also help improve comfort, create jobs, reduce greenhouse gas emissions, stimulate the economy, and help customers offset the impact of higher rates.

**Variance 1 (Table 3.2.6) Increase $16.1 million, Line 8, Column 8 (2023/24B vs 2022/23B)**

Demand Side Management spending is budgeted at $33.2 million (line 8, column 1) in the 2023/24 budget, an increase of $16.1 million from the 2022/23 NB Power Board approved budget. This increase is primarily due to proposed requirements under the *Electricity Act* that require NB Power to achieve specific energy savings targets.

AMI (ADVANCED METERING INFRASTRUCTURE) (Table 3.2.6, line 9)

NB Power is currently executing the Advanced Metering Infrastructure project that will replace approximately 360,000 residential and commercial meters across the province with smart meters and supporting infrastructure. Although the majority of the project costs are capital in nature, there are also OM&A costs required during implementation. AMI operating costs reflect meter base repairs, annual licensing and maintenance fees for the head end and network infrastructure, Meter Data Management (MDM) software as well as change management costs and customer communications and outreach during the mass deployment of meters.

**Variance 1 (Table 3.2.6) Decrease $0.2 million, Line 9, Column 8 (2023/24B vs 2022/23B)**

AMI OM&A spending is budgeted at $3.9 million (line 9, column 1) in the 2023/24 budget, a decrease of $0.2 million from the 2022/23 NB Power Board approved budget. This decrease is related to the specific work being done in that year. The annual AMI OM&A costs will vary from year to year depending on the maintenance and licensing fees required in that year as well as the number of meters being deployed and the communications required with customers during the deployment.

<u>ERP SYSTEM UPGRADE (Table 3.2.6, line 10)</u>

ERP System Upgrade will update NB Power's main ERP system SAP ECC6.. This is one of the most critical and complex business systems at NB Power and supports key processes throughout the organization including Financial Accounting, Treasury Management, Project Systems, Materials Management, and Plant Maintenance. The plan for 2023/24 includes the completion of work identified as prerequisites to the migration and enhancements to existing SAP-ECC platform. The scope of work will be aligned to the budget allocated, with all prerequisites addressed first, followed by enhancements to SAP-ECC based upon value to be realized by the business.

**Variance 1 (Table 3.2.6) Increase of $0.1 million, Line 10, Column 8 (2023/24B vs 2022/23B)**

ERP System Upgrade initiative is budgeted at $2.0 million (line 10, column 1) in the 2023/24 budget, an increase of $0.1 million from the 2022/23 NB Power Board approved budget. This increase reflects a change in scope of work.

**OTHER OM&A DRIVERS**

STORM CONTINGENCY

In 2019/20 NB Power adopted a new methodology for budgeting its annual storm contingency. The contingency is determined each year using the 5-year rolling average of prior year actuals. NB Power's 2023/24 storm contingency is budgeted at $6.7 million, comprising OM&A ($6.1 million) and capital ($0.6 million). This represents a decrease of $6.9 million ($5.2 million OM&A and $1.7 million capital) over the 2022/23 NB Power Board approved budgeted contingency of $12.6 million. Appendix P i, NB Power Storm Contingency, provides the calculation of the 2023/24 contingency as well as a breakdown of actual costs charged to the contingency in 2021/22. Actual storm spending for the 2020/21 and 2021/22 fiscal years was $4.8 million and $0.8 million, respectively.

CONTINUOUS IMPROVEMENT

NB Power continues to realize efficiencies and hard savings through a variety of continuous improvement activities. These achievements simplify our work and bring increased value to customers.

Efforts continue towards building capacity throughout the organization with plans to provide Lean Six Sigma training to 20 employees throughout the organization in the current fiscal year. Fifteen Green Belts will be certified in the business and will focus on localized improvements, and five Black Belts will be certified within a centralized group and will focus on more complex, cross functional improvements.

Industry best practice has demonstrated that focusing on small and large improvements helps to build and sustain the everyday mindset of continuous improvement. NB Power continues to use a variety of methods for improvement, such as Results Accelerators, which focus on achieving larger scale improvements within a 90-day period and Simplicity Tools designed to reduce complexity and eliminate non-value-added activities. Utilizing a variety of tools to make improvements provides NB Power with more ways to realize opportunities and solve problems.

Further to its continued efforts in growing a strong continuous improvement culture, NB Power has engaged PricewaterhouseCoopers (PwC) to lead a cost optimization review to identify areas of the company where we need to become more efficient to improve our overall costs. Our cost optimization results will lead to more efficient operations and better manage rate increase requirements. As a result, there is a $20 million credit recorded in Corporate Services OM&A as a placeholder for the planned savings to be achieved through the cost optimization initiative.

As part of the regular continuous improvement program, the 2023/24 budget includes a $7.5 million continuous improvement credit.  It is allocated at the Divisional level

Every effort has been made to incorporate the benefits achieved through regional collaboration into the work plans ($24 million annual on-going savings). Due to global supply chain issues and cost increases, NB Power's Procurement and Supply Chain resources have been focused on sustaining the value previously identified through this work.

Please refer to Appendix D Continuous Improvement and Continuity Schedule of Process Improvement, which provides a comprehensive listing of all continuous improvement projects and initiatives, including a continuity schedule view of each item. Tables 1, 2 and 3 contain a listing of continuous improvement projects and initiatives completed in 2019/20, 2020/21 and 2021/22, respectively. Table 4 contains those projects completed as of August 26, 2022 for the 2022/2023 year. These reflect hard savings that result in immediate benefit to the organization through the reduction of spending and cost avoidance benefits, achieved largely through regional collaboration efforts with NS Power and business area improvements, and soft savings through productivity improvements with the potential for sustainable long-term costs savings.

POINT LEPREAU NUCLEAR GENERATING STATION ("PLNGS") PERFORMANCE IMPROVEMENT

Key Performance indicators are measured to close gaps to industry best practice identified either internally through rigorous self-assessment processes, or externally through reviews by the World Association of Nuclear Operators (WANO), the Canadian Nuclear Safety

Commission (CNSC), NB Power's Nuclear Safety Review Board (NSRB), and other oversight bodies.

Over the last several years, significant efforts have been made to fully understand the equipment challenges at PLNGS. During Refurbishment, many upgrades were performed to nuclear specific components. However, there are several major components that require ongoing concerted effort to ensure excellent performance and long-term reliable operation.

The current aging of station equipment, both nuclear and non-nuclear, has resulted in an increased challenge with respect to emerging equipment deficiencies. The rate of completed maintenance at the station has steadily improved year over year, yet the rate of equipment degradation has gradually exceeded this.

Keeping safety as the top priority, efforts have been placed on the most significant issues to ensure that nuclear and conventional safety requirements and standards are always met or exceeded.  The cumulative effect has resulted in a growing backlog of deficient equipment which in the aggregate can challenge station reliability. PLNGS has a plan to address the backlog through a Priority Backlog Reduction improvement initiative set to begin in FY2022/23.

In recent years, PLNGS went through the process of implementing an Equipment Reliability Improvement Plan (ERIP). This was a comprehensive project that utilized internal and external subject matter experts to fully understand the equipment needs of the station. The project also categorized the safety significance and maintenance requirements of all plant equipment. This allows priority to be placed on the correct components at the correct time and provides a more thorough basis for plant monitoring and system health activities.

In addition to this, long term (up to 25 years) life cycle management plans have also been initiated. Several of these have been completed (large motors for example) and several are still in the process of being implemented. These plans incorporate industry best practices, and benefit from proven strategies within other stations. As each plan becomes finalized, long-term equipment upgrades and preventative maintenance strategies are developed, which allows for a more accurate financial plan for required resources, including personnel, materials and critical equipment. Improved planning of maintenance outages will also be an outcome of the life cycle management plans as work required on critical equipment will be able to be more effectively planned several years out and executed effectively. Emerging challenges, such as the need to re-wedge the main generator earlier than planned (a major contributor to the 2022 Outage extension) can therefore be more effectively planned.

As the current age-related challenges of the station are being addressed, the preventative approach of ERIP and the development of life cycle management plans will aim to return the station to a manageable baseline maintenance effort and ensure improved reliability and performance for future years.

Equipment Reliability Improvements

PLNGS continues work on a comprehensive approach to improving equipment reliability including ongoing implementation of the nuclear industry engineering standard AP-913 program, and ongoing maintenance improvements in the areas of fundamentals, standards and expectations, human performance, and quality assessments. The results of these efforts are producing positive results which are reflected in key industry metrics.

Two key performance indicators titled Equipment Reliability Index (“ERI”) and Forced Loss Rate (“FLR”) are used within the nuclear industry to track equipment reliability and overall performance and to enable nuclear stations to compare their results with each other to foster a culture of continuous improvement.

ERI is an indicator which uses a composite of 16 key sub-indicators that have a weighted value to add up to 100 as the highest score. This indicator reflects key areas of performance beyond those typically used for generation and system health alone. ERI is an effective instrument for measuring the longer-term trend of improvements and adherence to the principal areas of the engineering AP-913 standard, thus providing an indicator for sustainability over the long term. The PLNGS ERI in July 2022 was 73. This is primarily due to the two forced outages in 2021 and other consequential equipment failures. The station Continuous Improvement Plan includes actions to improve equipment reliability based on industry standards and internal assessments of performance. The actions focus on improving the rigour and focus provided by the Plant Health Committee and the Equipment Failure Review Committee. The target ERI for FY2022/23 is 85.

FLR is the ratio of all unplanned forced energy losses during a given period of time to the reference energy generation, minus energy generation losses corresponding to planned outages and any unplanned extension of planned outages. PLNGS' FLR scores were 14.04 per cent and 5.49 per cent for FY2020/21 and FY 2021/22, respectively. The FLR forecast for both FY2022/23 and FY2023/24 is 4.0 per cent.

<u>Planned Maintenance Outages</u>

Please refer to Section 5.1 Capital Projects and Appendix Q i. Point Lepreau Nuclear Generating Station Outage 2023 for information regarding PLNGS' planned maintenance outages.

<u>Workforce and Succession Planning</u>

Workforce management efforts continue at PLNGS to ensure current vacancies are filled in an effective and timely manner and that succession planning efforts mitigate the impacts of attrition.

Hiring of entry-level operations staff has continued at a rate of approximately 12 per year, with the exception of 2022/23. Subsequent to FY2023/24, approximately 6-8 new operators will be hired every two years. This plan has been put in place to support operational staffing needs with respect to required compliment and succession planning. These plant operators enter into an initial 18-month training program prior to becoming available for full shift duty. Additional multi-year senior training programs are underway for current operations staff to build appropriate complement levels for senior positions such as control room operators and shift supervisors. Having a full complement in these key positions is a fundamental requirement to ensure that the plant operates in a safe and effective manner. These efforts have demonstrated a strengthened complement of qualified operators.

PLNGS has also completed an assessment on critical positions ensuring that key information is captured, and proper knowledge transfer is occurring. Work has also been completed on recruitment efforts for the engineering and maintenance groups to address vacancy and succession planning requirements.

DEMAND SIDE MANAGEMENT

Demand side management (DSM) is an important component of NB Power's commitment to a vision of sustainable electricity and to be our customers' energy partner of choice. Although the primary goal of these programs is to promote the efficient use of energy in our customers' homes and businesses, they also help customers offset the impact of higher rates, help improve comfort, create jobs, reduce greenhouse gas emissions, and stimulate the economy. Table 3.2.7 shows the planned NB Power spending for each DSM program.

**Table 3.2.7**

**Demand Side Management**
(in millions $)

| | Component | (1) 2023/24B |
|---|---|---|
| | **Demand Side Management** | |
| (1) | Total Home Energy Savings Program | 16.1 |
| (2) | New Home Energy Savings Program | 2.0 |
| (3) | Energy Efficient Products Program | 1.4 |
| (4) | Business Rebate Program | 3.8 |
| (5) | Commercial Building Retrofit | 1.9 |
| (6) | Commercial New Construction Program | 0.8 |
| (7) | Industrial Energy Efficiency Program | 2.5 |
| (8) | Overhead | 1.1 |
| (9) | Enablement (non-evaluation activities) | 1.0 |
| (10) | Peak Rebate Program | 0.2 |
| (11) | Low Carbon Economy Fund | 2.5 |
| (12) | **Total Demand Side Management** | **$ 33.2** |

Note to reader: Financial tables reflect differences due to rounding

In 2023/24 the DSM plan includes $30.5 million (Table 3.2.7, lines 1 to 9, column 1) for the administration and delivery of energy efficiency programs. This is a significant increase in spending compared to previous years as a result of legislative changes that require NB Power to achieve specific energy reduction targets each year as set out in the proposed regulation. The draft regulation sets a 2023/24 reduction target of 0.5% of NB Power's forecasted total in-province electricity sales in kilowatt hours. For 2023/24, NB Power's total in-province sales are estimated to be 13,936 GWh[8] resulting in the prescribed minimum energy efficiency target for electricity of 69.7 GWh. NB Power used a combination of the DSM Potential Study and the DSM Model to determine the portfolio of programs to best

[8] Section 3.1b, Table 3.1.4, line 1, column 1

achieve the target and the associated cost. The $33.2 million being spent in the the test year will achieve an energy reduction of 57.1 GWh and a 18.4 MW reduction in demand. The 12.6 GWh gap between what NB Power will achieve with its own investment and the actual target will be made up from programs that are funded from other sources that also yield electricity savings.

NB Power will continue to offer programs in the residential, commercial and industrial sectors. There are no new programs being added in the test year; however, NB Power will start paying for the electricity portion of the Energy Efficiency Products and Business Rebate programs that were fully funded by provincial and federal funding for the last two years. Although DSM spending has increased, these costs are largely offset by adjustments to the new DSM regulatory deferral balance account. In 2023/24, $29.9 million[9] of the DSM spending will be offset by the adjustment to the deferral account.

For the details of all DSM activities in the test year including program plans, variance analysis, energy savings, cost effectiveness tests, and Evaluation, Measurement & Valuation (EM&V) activities please refer to Appendix AJ – 2023/24 DSM Initiatives Update[10]. Please refer to Appendix AV DSM 2023/24 Model[11] for supporting calculations of energy and demand savings and a list of any changes made to the model.

Table 3.7.2, Line 11, Column 1 shows $2.5 million in spending related to the Low Carbon Economy Fund (“LCEF”). For the first three years of LCEF funding (2018/19, 2019/20 and 2020/21) NB Power was not able to claim the full amount that the federal government had set up as a payable, leaving them with a debt to NB Power on their books. At year end 2020/21, in order to clear those payables and allow NB Power to use all of the funding, the federal government suggested that those claims be amended to allow us to claim the full amount of the funding with the understanding that by the end of the LCEF agreement NB Power would have to spend the equivalent in incremental NB Power dollars on LCEF eligible

[9] Section 3.6. Table 3.6.6, line 1, column 1
[10] Addresses Minimum Filing Requirements 111, 112, 114, 115, 117, 118, 126

expenditures to warrant the payout that had not yet been earned. Since 2023/24 is the final year of the LCEF, NB Power is required to spend $2.5 million to offset the unearned funding that was claimed in 2020/21.

NB Power will continue to act as the delivery agent for energy efficiency programs in the Province. These programs are funded through the LCEF initiative provided by the federal government, as well as a new Energy Efficiency Fund established through changes to the Electricity Act and corresponding proposed regulation. NB Power requires additional staff resources in order to develop and administer the programs under the different funding sources and expand its current programs to meet the new legislated targets. In the test year, six new positions are being added within Efficiency Services and one within Brand and Marketing to support this additional work. NB Power is able to get cost recovery for the time that employees spend on third-party funded programs. In the test year over $20 million will be leveraged to offer "all fuels" programs and meet other objectives set by the Province. In total, over $53 million will be invested to help customers manage their energy consumption and lower their bills.

NB Power's current demand response strategy focuses on programs that encourage customers to reduce or shift consumption to offset the annual system peak. In the 2023/24 test year the DSM Plan includes $0.2 million (Table 3.2.7, line 10, column1) to continue to offer the commercial demand response Peak Rebate program. This program is forecasted to achieve a 5 MW reduction in Annual Peak Hour Demand.

NB Power will continue to engage a third-party evaluator to evaluate DSM programs and validate the energy and demand savings claims that are being made. Seven program evaluations have been completed since Matter 458 (for fiscal years 2019/20 and 2020/21). For details refer to Appendix AX DSM Program Evaluations (program years 2019-20 and

[11] Addresses Minimum Filing Requirements 123 and 124

2020-21)[12]. NB Power did not evaluate any programs in fiscal 2021/22 because it was assumed that the results would be skewed by the impacts of the COVID-19 pandemic.

For additional reference, please refer to the following attached documents: , Appendix AW– 2023-24 DSM Evaluation Plan[13], Appendix AU – 2022 DSM Technical Reference Manual[14].

[12] Addresses Minimum Filing Requirement 125
[13] Addresses Minimum Filing Requirement 116
[14] Addresses Minimum Filing Requirements 119 and 120

## 3.3 DEPRECIATION and AMORTIZATION[1]

Depreciation and amortization expense is primarily driven by NB Power's investment in the generating, transmission and distribution systems. The depreciation of fixed assets is based on useful service lives. The straight-line method of depreciation is used for all assets. For distribution assets, the estimated service lives and depreciation rates were developed using the group depreciation concept, which consists of grouping depreciable property into similar groups and determining an average life of the group based on the "Equal Life Group" theory[2]. Depreciation is provided for all assets sufficient to depreciate the cost of such assets, less estimated salvage value, over their estimated service lives.

Depreciation and amortization expense in any given year is a function of the costs capitalized (additions) within the year or prior years (annualized impact over the useful service life), partially offset by reductions associated with prior capitalized amounts that have been fully depreciated or amortized.

NB Power has a Depreciation Review Committee that oversees engineering and financial reviews of service lives, salvage and decommissioning costs of all classes of fixed assets. Various assets are reviewed on an annual basis and any changes to asset lives or decommissioning estimates are presented to the Audit Committee of the Board of Directors for its review.  In addition, NB Power retains the services of an external party to assess asset lives on a regular basis (approximately every five years). NB Power retained the services of Concentric Advisors ULC in 2018/19 to conduct the most recent third-party study on NB Power's depreciation rates and asset lives. The results of the study are provided in AppendixG i, Depreciation Study Report 2019 NB Power Distribution and Appendix G iii, Depreciation Study Report 2019 NB Power Transmission.

**1** This section addresses Minimum Filing Requirements 61, 62, 63, 64 and 65.

2 The "Equal Life Group" theory involves subdividing the groups of assets into service lives and depreciating the assets in the subdivided groups together. The total depreciation for the group is the sum of the depreciation of the subdivided groups.

Following is a list of asset categories and the estimated service lives of the components.

**Property, Plant and Equipment**
**Estimated Service Lives**

| Assets | | Years |
|---|---|---|
| (1) | Nuclear generating stations | 4 - 57 |
| (2) | Hydro generating stations | 4 - 100 |
| (3) | Thermal generating stations | 2 - 64 |
| (4) | Combustion turbine generating stations | 10 - 40 |
| (5) | Transmission system | 14 - 70 |
| (6) | Terminals and substations | 15 - 62 |
| (7) | Distribution system | 10 - 53 |
| (8) | Buildings and properties | 20 - 54 |
| (9) | Computer systems | 6 |
| (10) | Motor vehicles | 8 - 21 |
| (11) | Miscellaneous assets | 15 |

The cost of distribution assets retired, less salvage, is charged to accumulated depreciation where it continues to depreciate over the average remaining life of the assets in the pool. For all other property, plant and equipment dispositions, the cost and accumulated depreciation is removed from the accounts, with the gain or loss on disposal being reflected in income. It should be noted that when the distribution system is impacted by significant storms the retired assets are written off immediately and are not accounted for under the equal life theory approach.

NB Power incurs costs at its generating stations for major inspections and overhauls. These costs are capitalized if they are considered major and occur in regular intervals of at least two years. They are capitalized as separate components and depreciated over the period to the next major inspection or overhaul.

For the fiscal year 2023/24, there was no change made to the depreciation and amortization policy.

**Table 3.3.1**

**NB Power Corporation**
**Depreciation and Amortization**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6) - (7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Depreciation and Amortization** | | | | | | | | | | | |
| (1) | Hydro generating station assets | $ 15.7 | $ 20.4 | $ 15.9 | $ 17.1 | $ 12.3 | $ 16.0 | $ 16.5 | $ (0.2) | $ 4.6 | $ 4.8 | $ (0.5) |
| (2) | Thermal generating station assets | 66.6 | 59.1 | 54.8 | 53.6 | 53.2 | 55.4 | 61.3 | 11.7 | 4.2 | 0.4 | (5.9) |
| (3) | Diesel, gas & other generating station assets | 5.6 | 5.7 | 5.8 | 5.4 | 5.5 | 5.5 | 5.8 | (0.2) | (0.0) | (0.1) | (0.3) |
| (4) | Nuclear generating station assets | 150.4 | 145.2 | 141.4 | 141.5 | 142.3 | 137.5 | 144.3 | 9.0 | 3.8 | (0.7) | (6.7) |
| (5) | Nuclear decommissioning and used nuclear fuel | 13.4 | 13.4 | 18.4 | 18.4 | 16.2 | 16.2 | 11.3 | (5.0) | (5.0) | 2.2 | 4.8 |
| (6) | Terminals & substation assets | 16.8 | 16.5 | 16.6 | 15.6 | 16.0 | 15.3 | 16.0 | 0.2 | (0.1) | (0.4) | (0.7) |
| (7) | Transmission assets | 14.0 | 13.2 | 13.2 | 12.5 | 12.3 | 10.2 | 10.7 | 0.7 | (0.0) | 0.2 | (0.5) |
| (8) | Distribution & water heater assets | 41.5 | 36.2 | 36.9 | 35.1 | 35.4 | 33.6 | 35.1 | 4.6 | (0.8) | (0.3) | (1.5) |
| (9) | General properties | 3.8 | 3.7 | 3.8 | 2.9 | 3.2 | 2.4 | 3.1 | 0.0 | (0.1) | (0.3) | (0.7) |
| (10) | Office equipment | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | (0.0) | (0.0) | (0.0) | - |
| (11) | Tools & equipment | 1.3 | 1.2 | 1.2 | 1.3 | 1.2 | 1.2 | 1.2 | 0.1 | (0.0) | 0.0 | 0.0 |
| (12) | Vehicles | 9.1 | 9.2 | 9.2 | 9.5 | 8.9 | 8.4 | 8.6 | (0.2) | (0.0) | 0.6 | (0.1) |
| (13) | Information systems | 1.2 | 0.6 | 0.6 | 0.7 | 0.3 | 0.3 | 0.4 | 0.6 | 0.0 | 0.3 | (0.0) |
| (14) | Customer contributions | (3.3) | (3.4) | (3.3) | (3.4) | (3.4) | (3.4) | (3.5) | 0.0 | (0.0) | (0.0) | 0.2 |
| (15) | Miscellaneous other | 32.6 | 23.0 | 28.3 | 33.4 | 25.9 | 22.1 | 20.0 | 4.3 | (5.3) | 7.5 | 2.1 |
| (16) | **Depreciation and Amortization** | $ 368.7 | $ 344.3 | $ 342.9 | $ 343.9 | $ 329.6 | $ 321.1 | $ 330.9 | $ 25.7 | $ 1.4 | $ 14.3 | $ (9.8) |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.3.1) Increase of $25.7 million Line 16, Column 8 (2023/24B vs 2022/23B)**

Depreciation and Amortization is budgeted to be $368.7 million (Table 3.3.1, line 16, column 1), an increase of $25.7 million (Table 3.3.1, line 16, column 8) compared to the 2022/23 budget of $342.9 million (Table 3.3.1, line 16, column 3). This variance is largely due to the following:

- Additional depreciation related to the PLNGS outage that occurred in 2022/23 - $16.7 million. This is a result of higher-than-expected expenditures as well as a full year of depreciation recognized in 2023/24 compared to nine-months planned in the 2022/23 budget.
- Additional depreciation related to Belledune and Coleson Cove outages that occurred in 2022/23 - $4.7 million. This is a result of higher than expected expenditures as well as a full year of depreciation recognized in 2023/24 compared to 6 months planned in the 2022/23 budget.
- Depreciation associated with outages at PLNGS, Belledune and Coleson Cove in 2023/24 - $7.8 million
- Increased depreciation associated with the new Bayside Generation Station gas turbine replacement - $3.8 million

Offset by

- reduced depreciation on PLNGS outages that reached the end of their economic life during the 2022/23 and 2023/24 fiscal years - $12.7 million

The balance of the depreciation variance is related to depreciation expense associated with recent and planned capital additions across all asset classes.

Refer to Appendix H – Nuclear Depreciation Detail (Excel format) for a breakdown of material changes to the nuclear depreciation expense.[3]

[3] This section addresses Minimum Filing Requirement 64.

## 3.4 TAXES[1]

Taxes are budgeted to be $54.0 million in 2023/24 (Table 3.4.1, line 4, column 1). Please refer to the following table and categories for the variances between the 2023/24 budget and the 2022/23 budget.

Taxes are paid to the Province of New Brunswick. The totals presented include amounts for:

- Property taxes - property tax has two components: provincial tax and municipal tax. The provincial tax is based on the assessed value of real properties at the provincial rate per $100 of assessed value and the municipal rate varies by municipality.
- Utility taxes - Utility taxes are paid under the *Assessment Act* and are based on the net book value ("NBV") of NB Power's assets (as at the end of the previous fiscal year) at a rate per $100 of NBV.
- Right of way taxes - Right of way taxes are assessed based on kilometers of distribution lines and the tax rate varies depending on the type of line.

[1] This section addresses Minimum Filing Requirements 66 and 67.

**Table 3.4.1**

**NB Power Corporation**
**Taxes**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6) - (7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Property taxes | $ 24.0 | $ 23.6 | $ 24.3 | $ 23.8 | $ 24.1 | $ 23.5 | $ 24.0 | $ (0.3) | $ (0.7) | $ (0.2) | $ (0.5) |
| (2) | Utility tax | 29.4 | 28.4 | 28.6 | 26.1 | 25.6 | 24.7 | 24.5 | 0.8 | (0.2) | 0.5 | 0.2 |
| (3) | Right of way tax | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.5 | 0.0 | 0.0 | 0.0 | 0.0 |
| (4) | **Total taxes** | $ 54.0 | $ 52.6 | $ 53.5 | $ 50.5 | $ 50.2 | $ 48.8 | $ 49.0 | $ 0.4 | $ (0.9) | $ 0.3 | $ (0.3) |

Note to reader: Financial tables reflect differences due to rounding

### Variance 1 (Table 3.4.1) Increase of $0.4 million – Line 4, Column 8 (2023/24B vs 2022/23B) [2]

Taxes are budgeted to be $54.0 million (line 4, column 1) in 2023/24, an increase of $0.4 million (line 4, Column 8) over the 2022/23 budget. The increase is related to an increase in utility taxes partially offset by a decrease in property tax. Utility taxes are budgeted to be higher by $0.8 million (line 2, Column 8) based on an increase in the asset base associated with the Distribution system and the Transmission system partially offset by a slightly lower tax rate. The utility tax rate for the 2023/24 budget is based on $2.076/$100 of Net Book Value (NBV) while the 2022/23 budget is based on $2.186/$100 of Net Book Value (NBV).

[2] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

## 3.5 FINANCE CHARGES AND OTHER INCOME[1]

Finance Costs are mainly a combination of interest and other related expenses associated with the debt held by NB Power, net of income earned on investment and sinking funds and interest capitalized to capital projects. A description of the main components of Finance Costs and Other Income is as follows:

Interest expense – includes interest on long-term debt, short-term debt, and the amortization of any associated premiums or discounts, interest rate hedges, post-employment benefit interest, interest on capital leases and other various charges.

Earnings from investment funds, sinking funds, and other investments – includes the income earned on the investment funds held in relation to nuclear decommissioning and used fuel management liabilities, the income earned on sinking funds held (as required by legislation), interest income, and other miscellaneous earnings.

Debt portfolio management fee – a management fee paid to the Province of New Brunswick amounting to 0.65 per cent of total long and short-term debt, net of the sinking funds, measured at the beginning of the fiscal year.

Foreign exchange (gains) or losses – gains or losses resulting from foreign exchange fluctuations. These gains or losses arise largely due to fluctuations in the converted Canadian value of United States dollar (USD) denominated debt, but also include amounts due to fluctuations in the value of foreign currency receivables and payables that occur throughout the year.

Interest capitalized – interest capitalized to capital projects during construction.

Accretion expense – an expense that recognizes the time value of money on the estimated expenditures for the thermal stations and nuclear decommissioning and used

[1] This section addresses Minimum Filing Requirements 68 and 69.

fuel management liabilities. It is essentially an annual budgeted interest charge on these forecasted liabilities.

Finance costs and other income for NB Power are outlined in Table 3.5.1.

**Table 3.5.1**

**NB Power Corporation**
**Finance costs and other income**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Finance** | | | | | | | | | | | |
| (1) | Interest expense | $ 205.0 | $ 195.5 | $ 172.7 | $ 183.4 | $ 184.8 | $ 187.0 | $ 201.5 | $ 32.3 | $ 22.8 | (1.4) | $ (14.5) |
| (2) | Earnings from investment funds, sinking funds, and other investments | (65.5) | (65.2) | (62.0) | (58.8) | (56.9) | (90.4) | (58.3) | (3.5) | (3.2) | (1.9) | (32.2) |
| (3) | Debt portfolio management fee | 32.5 | 31.8 | 31.8 | 31.8 | 31.8 | 31.8 | 31.7 | 0.7 | 0.0 | 0.0 | 0.1 |
| (4) | Foreign exchange (gains) or losses | - | 2.2 | 0.2 | (4.9) | (0.0) | (20.8) | (1.1) | (0.2) | 2.0 | (4.9) | (19.8) |
| (5) | Interest capitalized | (10.0) | (11.2) | (9.7) | (9.1) | (10.3) | (6.5) | (6.3) | (0.3) | (1.5) | $ 1.1 | (0.2) |
| (6) | **Sub-total** | $ 162.0 | $ 153.2 | $ 133.0 | $ 142.4 | $ 149.4 | $ 101.1 | $ 167.6 | $ 29.0 | $ 20.1 | $ (7.0) | $ (66.5) |
| | **Accretion** | | | | | | | | | | | |
| (7) | Accretion nuclear | $ 24.7 | $ 23.8 | $ 23.2 | $ 22.7 | $ 22.3 | $ 21.6 | $ 19.5 | $ 1.5 | $ 0.6 | $ 0.4 | $ 2.1 |
| (8) | Accretion used nuclear fuel | 20.1 | 19.4 | 19.9 | 18.9 | 18.9 | 18.0 | 17.3 | 0.2 | (0.5) | (0.0) | 0.6 |
| (9) | Accretion thermal | 6.5 | 6.2 | 5.3 | 5.2 | 5.6 | 4.2 | 5.2 | 1.2 | 1.0 | (0.4) | (1.0) |
| (10) | **Sub-total** | $ 51.3 | $ 49.4 | $ 48.3 | $ 46.7 | $ 46.7 | $ 43.7 | $ 42.0 | $ 3.0 | $ 1.1 | $ (0.0) | $ 1.7 |
| (11) | **Finance costs and other income** | $ 213.3 | $ 202.6 | $ 181.4 | $ 189.2 | $ 196.1 | $ 144.8 | $ 209.6 | $ 31.9 | $ 21.2 | $ (7.0) | $ (64.8) |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.5.1) Increase of $31.9 million – Line 11, Column 8 (2023/24B vs 2022/23B)** [2]

Finance costs and other income are budgeted to be $213.3 million (Table 3.5.1, line 11, column 1) in 2023/24, an increase of $31.9 million (Table 3.5.1, line 11, column 8) compared to the 2022/23 budgeted amount of $181.4 million. The major contributing factors to the increase are explained below.

- Interest expense – an increase of $32.3 million (Table 3.5.1, line 1, Column 8) – this increase is largely attributed to an increase in short and long-term debt interest expense due to higher rates and higher debt balances.

  Short-term debt interest rates are projected to be to 3.1 per cent in 2023/24 as compared to 0.4 per cent assumed for 2022/23, an increase of 2.7 per cent. Forecasted short-term debt rates were obtained from the Province's Department of Finance and Treasury Board in late June 2022. The rates are the average of the forecasts the Department received from its three lead domestic banks. The higher interest rate, partially offset by a lower average short-term debt balance, results in an increase in interest expense of $19 million.

  There is $300 million of long-term debt maturing in 2023/24 and $400 million is budgeted to be issued to refinance the maturing debt and to reduce the overall amount of short-term debt in the portfolio. The weighted average interest rate on the maturing debt is 3.36 per cent while the weighted average interest rate on the new debt issues is forecasted to be 4.00 per cent. In addition, NB Power is planning to issue $200 million of long-term debt in the fall of 2022 at a forecasted rate of 3.7 per cent, which will increase interest expense year over year. The forecasted rates reflect the average of 10- and 30-year bonds using data sourced from the Conference Board of Canada and Bloomberg. The increase in long-term interest rates and average debt balances, together with

[2] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

changes in the amortization of associated premiums and discounts, results in an increase in interest expense of $11.5 million. Table 3.5.2 below provides details of the maturing and budgeted long-term debt issues for 2023/24.

**Table 3.5.2**
**NB Power Corporation**
**Maturing & New Debt Analysis - 2023/24**
(in $ millions)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| | | | | **Maturing Debt** | | **New Debt** | |
| | Long-Term Debt Issues: | Maturity Date | Coupon Rate | Principal Balance | Annual Interest | Principal Balance | Annual Interest |
| (1) | 105 | Mar-24 | **4.67%** | 100.0 | 4.7 | 0.0 | 0.0 |
| (2) | 141 | Dec-23 | **2.70%** | 200.0 | 5.4 | 0.0 | 0.0 |
| (3) | FRC - B | Sep-53 | **4.00%** | 0.0 | 0.0 | 100.0 | 4.0 |
| (4) | FRC - C | Dec-53 | **4.00%** | 0.0 | 0.0 | 200.0 | 8.0 |
| (5) | FRC - D | Mar-54 | **4.00%** | 0.0 | 0.0 | 100.0 | 4.0 |
| (6) | Total | | | 300.0 | 10.1 | 400.0 | 16.0 |
| (7) | Amortization of debt items [1] | | | | 0.0 | | |
| (8) | Net Total | | | 300.0 | 10.1 | 400.0 | 16.0 |
| (9) | Weighted Average Rate | | | | 3.36% | | 4.00% |

**Notes:**
[1] Denotes an estimated annualized amount

- Earnings from investment funds, sinking funds, and other investments – increase of $3.5 million (Table 3.5.1, line 2, column 8) – the increase in earnings is split between the investment funds ($2.1 million) and sinking funds ($1.4 million). The higher earnings are due to higher average fund balances. The earnings rate assumed for the investment fund is 5.15 per cent and for the sinking fund the rate is 3.5 per cent. Both rates are consistent with the prior year budget. The earnings rate assumption for the investment fund portfolio is different from the sinking fund return assumption given the difference in the asset mix of the portfolios.

- Debt portfolio management fee – increase in the debt portfolio management fee of $0.7 million (Table 3.5.1, line 3, column 8) – the increase is a result of a higher opening net debt balance in 2023/24 as compared to the forecasted opening net debt balance assumed in the 2022/23 calculation.
- Foreign exchange (gains) or losses – decrease in the foreign exchange loss of $0.2 million (Table 3.5.1, line 4, column 8) – a foreign exchange difference occurs due to the revaluation of USD denominated debt at the new exchange rate each year. The remaining USD denominated debt matured in 2022/23 so there is no revaluation in the 2023/24 budget.
- Interest capitalized – increase in the amount of interest capitalized of $0.3 million (Table 3.5.1, line 5, column 8) – the increase is due to the timing of various projects The interest rate calculated for 2023/24 is outlined in Table 3.5.3 and is similar to the rate used in 2022/23.
- Accretion expense – an increase of $3.0 million (Table 3.5.1, line 10, column 8) - this increase is largely a result of higher accretion expense on the nuclear and thermal decommissioning liabilities. The variances are mainly related to higher discount rates and increases in the liability balances due to changes in estimates.

**Table 3.5.3**
**NB Power Corporation**
**Calculation of Financing Rate - 2023/24**
(in $ millions)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| | | | | **March 31, 2023** | | **March 31, 2024** | |
| | Long-Term Debt Issues: | Maturity Date | Coupon Rate | Principal Balance | Annual Interest | Principal Balance | Annual Interest |
| (1) | 90 | Dec-29 | 6.29% | 50.0 | 3.1 | 50.0 | 3.1 |
| (2) | 105 | Mar-24 | 4.67% | 100.0 | 4.7 | 0.0 | 0.0 |
| (3) | 106 | Sep-35 | 4.65% | 360.0 | 16.7 | 360.0 | 16.7 |
| (4) | 108 | Mar-37 | 4.55% | 100.0 | 4.6 | 100.0 | 4.6 |
| (5) | 109 | Mar-37 | 4.55% | 25.0 | 1.1 | 25.0 | 1.1 |
| (6) | 110 | Sep-39 | 4.80% | 160.0 | 7.7 | 160.0 | 7.7 |
| (7) | 112 | Sep-34 | 5.00% | 150.0 | 7.5 | 150.0 | 7.5 |
| (8) | 115 | Mar-34 | 5.15% | 50.0 | 2.6 | 50.0 | 2.6 |
| (9) | 118 | Sep-39 | 4.80% | 100.0 | 4.8 | 100.0 | 4.8 |
| (10) | 119 | Jun-41 | 4.80% | 200.0 | 9.6 | 200.0 | 9.6 |
| (11) | 126 | Jun-55 | 3.55% | 150.0 | 5.3 | 150.0 | 5.3 |
| (12) | 128 | Jun-65 | 3.55% | 200.0 | 7.1 | 200.0 | 7.1 |
| (13) | 131 | Jun-24 | 3.65% | 50.0 | 1.8 | 50.0 | 1.8 |
| (14) | 132 | Aug-45 | 3.80% | 250.0 | 9.5 | 250.0 | 9.5 |
| (15) | 135 | Jul-36 | 3.10% | 200.0 | 6.2 | 200.0 | 6.2 |
| (16) | 136 | Aug-27 | 2.35% | 100.0 | 2.4 | 100.0 | 2.4 |
| (17) | 137 | Aug-48 | 3.10% | 200.0 | 6.2 | 200.0 | 6.2 |
| (18) | 138 | Aug-27 | 2.35% | 120.0 | 2.8 | 120.0 | 2.8 |
| (19) | 139 | Aug-28 | 3.10% | 100.0 | 3.1 | 100.0 | 3.1 |
| (20) | 140 | Aug-48 | 3.10% | 250.0 | 7.8 | 250.0 | 7.8 |
| (21) | 141 | Dec-23 | 2.70% | 200.0 | 5.4 | 0.0 | 0.0 |
| (22) | 142 | Jun-65 | 3.55% | 60.0 | 2.1 | 60.0 | 2.1 |
| (23) | 143 | Aug-50 | 3.05% | 300.0 | 9.2 | 300.0 | 9.2 |
| (24) | 144 | Jun-65 | 3.55% | 150.0 | 5.3 | 150.0 | 5.3 |
| (25) | 145 | Jun-65 | 3.55% | 100.0 | 3.6 | 100.0 | 3.6 |
| (26) | 146 | Dec-39 | 2.71% | 50.0 | 1.4 | 50.0 | 1.4 |
| (27) | 147 | Aug-50 | 3.05% | 150.0 | 4.6 | 150.0 | 4.6 |
| (28) | 148 | Oct-57 | 2.34% | 150.0 | 3.5 | 150.0 | 3.5 |
| (29) | 149 | Aug-52 | 2.90% | 300.0 | 8.7 | 300.0 | 8.7 |
| (30) | 150 | Aug-25 | 1.80% | 200.0 | 3.6 | 200.0 | 3.6 |
| (31) | FRC - A | Nov-52 | 3.70% | 200.0 | 7.4 | 200.0 | 7.4 |
| (32) | FRC - B | Sep-53 | 4.00% | 0.0 | 0.0 | 100.0 | 4.0 |
| (33) | FRC - C | Dec-53 | 4.00% | 0.0 | 0.0 | 200.0 | 8.0 |
| (34) | FRC - D | Mar-54 | 4.00% | 0.0 | 0.0 | 100.0 | 4.0 |
| (35) | Amortization of debt items [1] | | | | 3.9 | | 4.1 |
| (36) | Total | | | 4,775.0 | 173.2 | 4,875.0 | 179.3 |
| (37) | Weighted Average Rate | | | | 3.63% | | 3.68% |
| (38) | Debt Portfolio Management Fee | | | | 0.65% | | 0.65% |
| (39) | Total Interest Rate | | | | 4.28% | | 4.33% |
| (40) | **Average of Opening / Ending Interest Rate** | | | | **4.30%** | | |

**Notes:**
[1] Amortization of debt items includes the amortization of premiums, discounts and interest rate hedges.

## 3.6 REGULATORY BALANCE ADJUSTMENTS[1]

There are seven regulatory balance accounts included in Net Change in Regulatory Balances:

- Point Lepreau Nuclear Generating Station ("PLNGS") [2]
- Lawsuit settlement with Petroleos de Venezuela S.A ("PDVSA")
- Allowance for funds used during construction ("AFUDC")
- Meter write-off deferral
- Energy efficiency and demand response deferral
- Energy supply cost variance account
- Electricity sales and margin variance account

[1] This section addresses Minimum Filing Requirements 70, 71, 72, 73 and 74.
[2] On March 26, 2018, NB Power announced that it had reached a settlement with several insurers who underwrote a construction all risk insurance policy during the refurbishment project. The settlement is subject to a confidentiality agreement between NB Power and the Insurers.

**Table 3.6.1**

**NB Power Corporation**
**Net Change in Regulatory Balances**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Regulatory balance - Point Lepreau Nuclear Generating Station | $ 26.8 | $ 25.5 | $ 27.5 | $ 25.9 | $ 26.2 | $ 24.7 | $ 24.7 | $ (0.7) | $ (2.0) | $ (0.2) | $ 0.0 |
| (2) | Regulatory balance - Lawsuit settlement PDVSA | (12.8) | (12.0) | (12.6) | (11.8) | (11.3) | (10.6) | (10.2) | (0.2) | 0.6 | (0.5) | (0.3) |
| (3) | Regulatory balance - AFUDC | (0.9) | (0.3) | (0.6) | (0.4) | (0.7) | (0.7) | (0.6) | (0.3) | 0.3 | 0.3 | (0.1) |
| (4) | Regulatory balance - Meter Write-off Deferral | (5.5) | - | (1.6) | - | (1.3) | - | - | (3.9) | 1.6 | 1.3 | - |
| (5) | Regulatory balance - DSM Deferral | (29.5) | (15.5) | - | - | - | - | - | (29.5) | (15.5) | - | - |
| (6) | Regulatory balance - Sales & Margin Variance | (56.5) | 89.0 | - | - | - | - | - | (56.5) | 89.0 | - | - |
| (7) | Regulatory balance - Energy Supply Cost Variance | 62.7 | (129.5) | - | - | - | - | - | 62.7 | (129.5) | - | - |
| (8) | **Net Change in Regulatory Balances** | $ (15.8) | $ (42.9) | $ 12.8 | $ 13.8 | $ 12.8 | $ 13.5 | $ 13.9 | $ (28.6) | $ (55.7) | $ 0.9 | $ (0.4) |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.6.1) Decrease of $28.6 million, Line 8, Column 8 (2023/24B vs 2022/23B)** [2]

Net change in regulatory balances is budgeted to be $(15.8) million in 2023/24B, a decrease of $28.6 million compared to 2022/23B. Please refer to the subsequent tables for detailed variances for each regulatory balance.

REGULATORY BALANCE – POINT LEPREAU NUCLEAR GENERATING STATION

On January 13, 2014, the Board approved the implementation of a regulatory deferral account to record the deferral of certain expenses related to the PLNGS Refurbishment Outage, to be recovered from customers over the extended life of the Station. In 2013 the Board

[2] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

approved a balance of $1.036 billion to be recovered from customers over 27 years. Table 3.6.2 presents further details of the Net Change in Regulatory Balance - Point Lepreau Nuclear Generating Station.

**Table 3.6.2**

**NB Power Corporation**
**Net Change in Regulatory Balance - Point Lepreau Nuclear Generating Station**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6) - (7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Amortization | $ 53.3 | $ 53.5 | $ 58.4 | $ 57.8 | $ 58.8 | $ 59.3 | $ 59.3 | $ (5.2) | $ (4.9) | $ (1.0) | $ (0.0) |
| (2) | Interest on regulatory balance | (26.5) | (28.0) | (30.9) | (31.9) | (32.6) | (34.6) | (34.6) | 4.4 | 2.9 | 0.7 | 0.1 |
| (3) | **Net change in regulatory balance Point Lepreau Nuclear Generating Station** | $ 26.8 | $ 25.5 | $ 27.5 | $ 25.9 | $ 26.2 | $ 24.7 | $ 24.7 | $ (0.7) | $ (2.0) | $ (0.2) | $ 0.0 |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.6.2) Decrease of $0.7 million, Line 3, Column 8 (2023/24B vs 2022/23B)**

The budgeted annual change in the PLNGS regulatory balance is $26.8 million (Table 3.6.2, line 3, column 1). The net decrease of $0.7 million (Table 3.6.2, line 3, Column 8) in 2023/24B compared to 2022/23B is due to a lower regulatory balance and a decreased interest rate.

Please refer to Appendix BB i. PLNGS Regulatory Deferral Continuity Schedule for the continuity schedule for the PLNGS regulatory balance. The confidential version of this schedule is found in Appendix CONF T PLNGS Regulatory Deferral Continuity Schedule Confidential. This document is being filed under the Board's policy on confidentiality.

## REGULATORY BALANCE – LAWSUIT SETTLEMENT WITH PDVSA

On August 23, 2007, the Board approved the implementation of a regulatory deferral account. The savings associated with the lawsuit settlement with Petroleos de Venezuela S.A. ("PDVSA") would be realized over the economic life (23 years) of the Coleson Cove generating station but would be provided to customers on a levelized basis over a period of 17 years.

In its 2017/18 general rate application, NB Power requested that the Board vary the order of August 23, 2007 and extend the term of the PDVSA regulatory account to correspond with the updated economic life of the Coleson Cove generating station and the term of the benefits associated with the settlement. In June 2017, the Board approved NB Power's application for the extension of the term of the PDVSA regulatory deferral account, to the current economic life of the Coleson Cove Generating Station.

The components of the regulatory balance include depreciation and interest savings, the levelized benefit to customers, and interest on the regulatory balance.

### Levelized benefit

This reflects the equalized amortization of the regulatory balance.

### Interest

The interest charged on the regulatory balance is the expected weighted average cost of debt.

### Depreciation and interest savings

The ongoing savings reflected in the regulatory balance include:

- reduced depreciation (the settlement reduced the net book value of the station)
- lower financing costs (interest savings)

### Depreciation savings

The settlement proceeds were credited to the net book value ("NBV") of the station. The credit is depreciated over the remaining life of the station.

Interest savings

The interest savings is calculated on the settlement. Since the settlement was credited to the NBV of the station the full benefit is not realized until the end of life of the station. The total settlement represents the principal balance on which the interest calculation is based. The principal balance is drawn down monthly on a straight-line basis over the life of the station (to match the depreciation). The interest savings calculation is calculated on the average remaining monthly balance.

Table 3.6.3 presents further details of the Net Change in Regulatory Balance - Lawsuit Settlement with PDVSA.

**Table 3.6.3**

**NB Power Corporation**
**Net Change in Regulatory Balance - Lawsuit Settlement with PDVSA**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6) - (7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Depreciation and interest savings | $ 14.5 | $ 14.9 | $ 14.9 | $ 15.2 | $ 15.2 | $ 15.5 | $ 15.5 | $ (0.3) | $ (0.0) | $ 0.0 | $ 0.0 |
| (2) | Levelized benefit to customers | (21.5) | (21.5) | (22.0) | (22.0) | (21.5) | (21.5) | (21.1) | 0.5 | 0.5 | (0.5) | (0.3) |
| (3) | Interest on Regulatory Balance | (5.8) | (5.3) | (5.4) | (4.9) | (5.0) | (4.6) | (4.6) | (0.4) | 0.1 | 0.0 | 0.0 |
| (4) | **Net change in regulatory balance lawsuit settlement with PDVSA** | $ (12.8) | $ (12.0) | $ (12.6) | $ (11.8) | $ (11.3) | $ (10.6) | $ (10.2) | $ (0.2) | $ 0.6 | $ (0.5) | $ (0.3) |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.6.3) Increase in the credit by $0.2 million, Line 4, Column 8 (2023/24B vs 2022/23B)**

The Net Change in Regulatory Balance - Lawsuit Settlement with PDVSA is budgeted to be a credit of $12.8 million (Table 3.6.3, line 4, column 1), an increase in the credit of $0.2 million (Table 3.6.3, line 4, Column 8) in 2023/24B compared to 2022/23B. This is mainly due to lower interest rates resulting in a lower levelized benefit to customers, partially offset by lower-than-expected interest savings and higher interest costs on the deferral as a result of a higher overall deferral balance.

Please refer to Appendix BB ii. PDVSA Regulatory Deferral Continuity Schedule for the continuity schedule for the lawsuit settlement with PDVSA regulatory balance.

REGULATORY BALANCE – ALLOWANCE FOR FUNDS USED DURING CONTRUCTION (AFUDC)

NB Power's accounting policy is to capitalize interest during construction ("IDC") on assets under construction with the exception of Transmission assets where AFUDC and IDC are capitalized. IDC and AFUDC recognize the use of debt and equity in the financing of new construction.

**Table 3.6.4**

**NB Power Corporation**
**Net Change in Regulatory Balance - Allowance for Funds Used During Construction**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6) - (7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Allowance for Funds Used During Construction | $ (1.1) | $ (0.5) | $ (0.7) | $ (0.6) | $ (0.9) | $ (0.8) | $ (0.7) | $ (0.3) | $ 0.3 | $ 0.3 | $ (0.1) |
| (2) | Amortization | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.1 | (0.0) | - | 0.0 | (0.0) |
| (3) | **Net change in regulatory balance AFUDC** | $ (0.9) | $ (0.3) | $ (0.6) | $ (0.4) | $ (0.7) | $ (0.7) | $ (0.6) | $ (0.3) | $ 0.3 | $ 0.3 | $ (0.1) |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.6.4) Increase in the credit by $0.3 million, Line 3, Column 8 (2023/24B vs 2022/23B)**

The budgeted annual adjustment to income is a credit of $0.9 million (Table 3.6.4, line 3, column 1) for AFUDC. This increase of the credit by $0.3 million (Table 3.6.4, line 3, Column 8) is due to increased capital spending included in the 2023/24 budget compared to the previous year's plan.

Please refer to Appendix BB iii. for the continuity schedule for AFUDC.

REGULATORY BALANCE – METER WRITE-OFF DEFERRAL

As part of NB Power's Advanced Metering Infrastructure (AMI) project, in September 2020 the Board approved the implementation of a regulatory deferral account with respect to the amortization of the remaining book value of its currently installed electricity meters.

**Table 3.6.5**

**NB Power Corporation**
**Net Change in Regulatory Balance - AMI Meter Write Off**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Meter Write Off | $ (9.2) | - | $ (5.0) | - | $ (1.3) | - | - | $ (4.1) | $ 5.0 | $ 1.3 | - |
| (2) | Amortization | 3.7 | - | 3.4 | - | - | - | - | 0.2 | (3.4) | - | - |
| (3) | **Net change in regulatory balance AMI Meter Write Off** | $ (5.5) | - | $ (1.6) | - | $ (1.3) | - | - | $ (3.9) | $ 1.6 | $ 1.3 | - |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.6.5) Increase in the credit by $3.9 million, Line 3, Column 8 (2023/24B vs 2022/23B)**

The budgeted annual change in the meter write-off deferral account is a credit of $5.5 million (Table 3.6.5, line 3, column 1). This increase of the credit by $3.9 million (Table 3.6.5, line 3, Column 8) is due to additional meters written off as replaced by new AMI meters, partially offset by amortization of deferral.

Please refer to Appendix BB iv. AMI Regulatory Deferral Continuity Schedule.

REGULATORY BALANCE – ENERGY EFFICIENCY AND DEMAND RESPONSE DEFERRAL

Recent amendments to the *Electricity Act* included the creation of the energy efficiency and demand response deferral account. Demand Side Management (DSM) includes both energy efficiency and demand response expenditures incurred by organizations in an effort to defer or eliminate future energy and capacity requirements. The creation of a deferral account for DSM expenditures will result in a regulatory balance on NB Power's financial statements. Qualifying costs will be added to the account annually and amortized over a 10-year period.

**Table 3.6.6**

**NB Power Corporation**
**Net Change in Regulatory Balance - Energy Efficiency and Demand Response Deferral**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Qualifying Costs | $ (29.9) | $ (15.2) | - | - | - | - | - | $ (29.9) | $ (15.2) | - | - |
| (2) | Interest on regulatory balance | (1.2) | (0.3) | - | - | - | - | - | (1.2) | (0.3) | - | - |
| (3) | Amortization | 1.6 | - | - | - | - | - | - | 1.6 | - | - | - |
| (4) | **Net change in regulatory balance Energy Efficiency and Demand Response Deferral** | $ (29.5) | $ (15.5) | - | - | - | - | - | $ (29.5) | $ (15.5) | - | - |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.6.6) Increase in the credit by $29.5 million, Line 4, Column 8 (2023/24B vs 2022/23B)**

The budgeted annual adjustment to income is a credit of $29.5 million (Table 3.6.6, line 4, column 1), including qualifying costs of $29.9 million and interest expense of $1.2 million, partially offset by amortization of $1.6 million. The variance against the 2022/23 budget (Table 3.6.6, line 4, column 3) is due to application of Regulation 2022-17 under the *Electricity Act* which came into effect on April 1, 2022 but was not included in the 2022/23 budget due to timing.

Please refer to Appendix BB v. Energy Efficiency and Demand Response Deferral Continuity Schedule.

## REGULATORY BALANCE – ENERGY SUPPLY COST VARIANCE ACCOUNT

Recent amendments to the *Electricity Act* included the creation of the energy supply cost variance account. The variance account will record the difference (less $5 million incentive threshold) between the actual and forecasted monthly energy supply costs recovered through the sales of energy to in-province customers. The balance in the account at each October 31$^{st}$ will be recovered from or reimbursed to customers through a rate rider effective the following April 1.

**Table 3.6.7**

**NB Power Corporation**
**Net Change in Regulatory Balance - Energy Supply Cost Variance**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Energy Supply Cost Varaince | - | (129.1) | - | - | - | - | - | - | (129.1) | - | - |
| (2) | Rate Rider Adjustment Factor | 66.4 | - | - | - | - | - | - | 66.4 | - | - | - |
| (3) | Interest on regulatory balance | (3.7) | (0.4) | - | - | - | - | - | (3.7) | (0.4) | - | - |
| (4) | **Net change in regulatory balance Energy Supply Cost Variance** | $ 62.7 | $ (129.5) | - | - | - | - | - | $ 62.7 | $ (129.5) | - | - |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.6.7) Increase of $62.7 million, Line4, Column 8 (2023/24B vs 2022/23B)**

The budgeted annual adjustment to income is $62.7 million (Table 3.6.7, line 4, column 1), including the rate rider adjustment factor[3] of $66.4 million partially offset by interest expense of $(3.7) million. The variance against the 2022/23 budget (Table 3.6.7, line 4, column 3) is due to application of Regulation 2022-17 under the *Electricity Act* which came into effect on April 1, 2022 but was not included in the 2022/23 budget due to timing.

[3] The rate rider adjustment is related to previous year supply and sales variances to ensure only actual costs are charged to customers, this amount is an offset to the rate rider adjustment factor included in revenue.

Please refer to Appendix BB vi. Gross Margin Variance Continuity Schedule.

REGULATORY BALANCE – ELECTRICITY SALES AND MARGIN VARIANCE ACCOUNT

Recent amendments to the Electricity Act included the creation of the electricity sales and margin variance account. The variance account will record the difference (less $5 million incentive threshold), between the actual and forecasted revenue and margin from sales of energy, capacity and renewable energy credits to both in-province and out-of-province customers, which shall be calculated as the sum of the out-of-province gross margin variance, the load-price variance and the load-volume variance. The balance in the account at each October 31 will be recovered from or reimbursed to customers through a rate rider effective the following April 1.

**Table 3.6.8**

**NB Power Corporation**
**Net Change in Regulatory Balance - Electricity Sales and Margin Variance**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Electricity Sales and Margin Variance | - | 87.0 | - | - | - | - | - | - | 87.0 | - | - |
| (2) | Rate Rider Adjustment Factor | (58.7) | - | - | - | - | - | - | (58.7) | - | - | - |
| (3) | Interest on regulatory balance | 2.2 | 2.0 | - | - | - | - | - | 2.2 | 2.0 | - | - |
| (4) | **Net change in regulatory balance Electricty Sales and Margin Variance** | $ (56.5) | $ 89.0 | - | - | - | - | - | $ (56.5) | $ 89.0 | - | - |

Note to reader: Financial tables reflect differences due to rounding

**Variance (Table 3.6.8) Increase in the credit by $56.5 million, Line 4, Column 8 (2023/24B vs 2022/23B)**

The budgeted annual adjustment to income is a credit of $56.5 million (Table 3.6.8, line 4, column 1), including the rate rider adjustment factor[4] of $(58.7) million partially offset by interest expense of $2.2 million. The variance against the 2022/23 budget (Table 3.6.7, line 4, column 3) is due to application of Regulation 2022-17 under the *Electricity Act* which came into effect on April 1, 2022 and had no impact on the 2022/23 budget and was applied to the 2022/23 forecast as noted in line 4, column 2.

Please refer to Appendix BB vi. Gross Margin Variance Continuity Schedule.

[4] The rate rider adjustment is related to previous year supply and sales variances to ensure only actual costs are charged to customers, this amount is an offset to the rate rider adjustment factor included in revenue.

## 3.7 NET EARNINGS[1]

NB Power's costs are driven by the cost of fuel and purchased power, costs required to run and maintain operation of the utility, depreciation of capital investments, costs required to finance operations and investments, and changes in regulatory balances. The revenue to cover these costs comes from in-province sales, out-of-province sales and miscellaneous revenue. NB Power's net earnings are budgeted to be $13.9 million in 2023/24.

The overarching financial goals of NB Power are to reduce debt and create equity in order to provide the utility with some flexibility to manage operating and financial risk, to respond to changing markets and technologies, and to better prepare for future investment requirements. These goals are realized in part from the net earnings the company realizes each year. These financial goals also align with the legislative obligation under the *Electricity Act* that rates charged to customers should be sufficient to permit a just and reasonable return that will allow NB Power to earn sufficient income in order to achieve and sustain a capital structure of at least 20 per cent equity.

Net earnings is challenged this year due to significant upward cost pressures, most notably on fuel and purchased power expenses (refer to section 3.1a). Due to these extraordinary cost increases, NB Power's requested rate increase of 8.9 per cent will only result in a very modest net earnings of $13.9 million, which does not allow for any meaningful progress toward the company's mandated financial targets or reduction of debt in the test year.

[1] This section addresses Minimum Filing Requirement 75.

**Table 3.7.1**

**NB Power Corporation**
**Net Earnings**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Net Earnings (in millions $) | $ 13.9 | $ 32.5 | $ 39.8 | $ 80.6 | $ 67.6 | $ (4.2) | $ 40.9 | $ (25.8) | $ (7.3) | $ 13.0 | $ (45.1) |
| (2) | MWh Delivered (in thousands) | 19,202 | 20,912 | 17,379 | 20,897 | 16,546 | 18,742 | 16,942 | 1,823 | 3,533 | 4,350 | 1,801 |
| (3) | Net Earnings / MWh | $ 0.73 | $ 1.55 | $ 2.29 | $ 3.86 | $ 4.09 | $ (0.22) | $ 2.41 | $ (1.56) | $ (0.74) | $ (0.23) | $ (2.64) |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 3.7.1) Decrease of $25.8 million – Line 1, Column 8 (2023/24B vs 2022/23B)** [2]

Net Earnings are budgeted to be $13.9 million (Table 3.7.1, line 1, column 1) in 2023/24, a decrease of $25.8 million (Table 3.7.1, line 1, column 8) compared to the 2022/23 budget. Variance explanations for the changes in Net Earnings are included by component in the applicable sections.

**Variance 1 (Table 3.7.1) Increase of 1,823 MWh Line 2, Column 8 (2023/24B vs 2022/23B)**

MWh delivered (in thousands) are budgeted to be 19,202 (Table 3.7.1, line 2, column 1) in 2023/24, an increase of 1,823 MWh (in thousands) (Table 3.7.1, line 2, column 8) compared to the 2022/23 budget. The increase is mainly a result of higher out-of-province sales.

[2] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

**Variance 1 (Table 3.7.1) Decrease of $1.56 - Line 3, Column 8 (2023/24B vs 2022/23B)**

Net Earnings/MWh are budgeted to be $0.73 (Table 3.7.1, line 3, column 1) in 2023/24, a decrease of $1.56/MWh (Table 3.7.1, line 3, column 8) compared to the 2022/23 budget. The decrease is due to the decrease in budgeted Net Earnings and an increase in budgeted MWh delivered.

# 4.0 REVENUE DETAILS

NB Power's revenue derives from three primary sources: in-province sales of power, out-of-province sales of power, and miscellaneous revenue.

## 4.1 In-Province Sales[1]

The budgeted revenue from the in-province sales of power for each customer class for 2023/24, assuming an 8.9 per cent rate increase effective April 1, 2023, is presented in Table 4.1.1 below.

[1] This section addresses Minimum Filing Requirements 76, 77, 78, 79, 80 and 81.

**Table 4.1.1**

**NB Power Corporation**
**In-Province Sales of Power**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Residential | $ 803.1 | $ 735.1 | $ 711.4 | $ 701.0 | $ 699.4 | $ 668.7 | $ 704.6 | $ 91.7 | $ 23.8 | $ 1.6 | $ (35.9) |
| (2) | General Service | 338.6 | 304.9 | 312.0 | 294.5 | 301.4 | 276.1 | 311.4 | 26.6 | (7.1) | (6.8) | (35.3) |
| (3) | Industrial Distribution | 92.1 | 84.2 | 84.4 | 80.8 | 82.4 | 77.0 | 82.1 | 7.7 | (0.2) | (1.6) | (5.2) |
| (4) | Industrial Transmission | 303.2 | 244.3 | 222.6 | 219.8 | 219.4 | 223.2 | 247.4 | 80.5 | 21.6 | 0.5 | (24.2) |
| (5) | Industrial Interruptible | 63.8 | 143.8 | 58.4 | 89.4 | 41.2 | 40.8 | 32.5 | 5.4 | 85.4 | 48.2 | 8.4 |
| (6) | Wholesale | 118.4 | 119.2 | 123.7 | 115.9 | 120.4 | 112.0 | 124.7 | (5.3) | (4.5) | (4.5) | (12.7) |
| (7) | Non-metered | 30.5 | 27.8 | 27.7 | 26.8 | 26.7 | 26.2 | 26.9 | 2.8 | 0.2 | 0.2 | (0.7) |
| (8) | **In-province sales of power** | $ 1,749.7 | $ 1,659.4 | $ 1,540.2 | $ 1,528.3 | $ 1,490.8 | $ 1,424.0 | $ 1,529.7 | $ 209.5 | $ 119.2 | $ 37.5 | $ (105.7) |
| (9) | Rate Rider Adjustment Factor | $ 7.9 | $ - | $ - | $ - | $ - | $ - | $ - | 7.9 | - | - | - |
| (10) | **Total In-province revenue** | $ 1,757.5 | $ 1,659.4 | $ 1,540.2 | $ 1,528.3 | $ 1,490.8 | $ 1,424.0 | $ 1,529.7 | $ 217.4 | $ 119.2 | $ 37.5 | $ (105.7) |

Note to reader: Financial tables reflect differences due to rounding

The rate rider adjustment is related to previous year supply and sales variances to ensure only actual costs are charged to customers, this amount is offset in net change in regulatory balances.

**Variance 1 (Table 4.1.1) Increase of $217.4 million – Line 10, Column 8 (2023/24B vs 2022/23B)**

The total budgeted in-province sales of power is $1,749.7 million (Table 4.1.1, line 8, column 1) in 2023/24, an increase of $209.5 million (Table 4.1.1, line 8, column 8) compared to the total budgeted revenue in 2022/23. This increase is mainly attributable to the budgeted 8.9 per cent increase in rates effective April 1, 2023, growth in Residential and Industrial Transmission sales, offset by decreases in Wholesale and Interruptible sales. The variances are described in more detail in the subsequent sections.

**BUDGETED ENERGY SALES VOLUME (ENERGY)**

During the spring of 2022, NB Power updated the 10-Year Load Forecast for 2023/24 with details provided in Appendix AD i, 2023-2033 Load Forecast. A working MS Excel model is also provided in Appendix AY, Load Forecasting Model Redacted[2]. The confidential version of this model is found in Appendix CONF S – Load Forecasting Model Confidential. This document is being filed under the Board's Policy on Confidentiality.

The major assumptions used to budget 2023/24 sales include:

- Gross Domestic Product ("GDP") growth of 1.6 per cent in 2023/24 based on the Provincial Government's Economic Outlook released in March 2022
- Known major industrial load changes based on account manager input and public announcements
- The addition of 2,586 new year-round residential customers in 2023/24 based on historical customer growth and population projections
- Normal weather (4,531 heating-degree-days) based on weighted 20-year average temperature history (from 2002/03 to 2021/22)
- Estimates of energy reductions from NB Power's Demand Side Management programs, as well as non-program driven energy conservation savings

[2] This addresses Minimum Filing Requirement 77.

- Penetration of electric space and water heating, and air conditioning based on 2018 Energy Planning Survey results

Revenue for each customer class is budgeted from the energy sales, unit rate trend analysis and billing determinants. This process is described in more detail in the Revenue Forecast Development section below.

**Table 4.1.2**

**NB Power Corporation**
**In-Province Energy Sales Volume (Energy)**
Fiscal Years Ending March 31
(GWh)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6) - (7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Residential | 5,487.8 | 5,474.4 | 5,287.2 | 5,363.0 | 5,304.6 | 5,158.6 | 5,351.1 | 200.6 | 187.2 | 58.4 | (192.5) |
| (2) | General Service | 2,294.3 | 2,257.8 | 2,317.3 | 2,235.8 | 2,263.8 | 2151.7 | 2348.6 | (23.0) | (59.5) | (28.0) | (196.9) |
| (3) | Industrial Distribution | 759.8 | 765.4 | 816.5 | 767.6 | 773.2 | 766.6 | 770.3 | (56.8) | (51.1) | (5.6) | (3.7) |
| (4) | Industrial Transmission | 3,507.8 | 3,057.1 | 2,788.5 | 2,808.2 | 2,809.0 | 2,866.0 | 3,174.6 | 719.3 | 268.5 | (0.8) | (308.6) |
| (5) | Industrial Interruptible | 748.0 | 1,120.4 | 1,151.3 | 1,086.2 | 987.2 | 837.2 | 639.5 | (403.3) | (30.9) | 99.0 | 197.7 |
| (6) | Wholesale | 1,082.7 | 1,191.6 | 1,234.5 | 1,179.1 | 1,229.1 | 1159.0 | 1267.8 | (151.9) | (42.9) | (50.0) | (108.8) |
| (7) | Non-metered | 55.4 | 55.8 | 57.2 | 58.0 | 42.9 | 44.0 | 44.2 | (1.8) | (1.4) | 15.1 | (0.2) |
| **(8)** | **In-province sales of power** | 13,935.7 | 13,922.5 | 13,652.5 | 13,497.8 | 13,409.8 | 12,983.1 | 13,596.1 | 283.2 | 270.0 | 88.1 | (613.0) |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 4.1.2) Increase of 283.2 GWh – Line 8, Column 8 (2023/24B vs 2022/23B) [3]**

Total budgeted sales volume is projected to increase by 283.2 GWh (Table 4.1.2, line 8, column 8) in the 2023/24 budget. An analysis of the budgeted sales volume increase in the 2023/24 budget compared to the 2022/23 NB Power Board approved budget follows.

[3] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

RESIDENTIAL

The Residential classification, which includes year-round and seasonal households, churches, and farms, represents a 200.6 GWh (line 1, column 8) net increase in energy sales. The increase in sales is driven primarily by higher population forecasts resulting in growth in the number of customers and increased electric heating penetration based on the results of the 2018 Energy Planning Survey, partially offset by the incremental impact of energy efficiency programs which decrease sales by 19 GWh.

GENERAL SERVICE

The General Service classification is comprised of mostly commercial and institutional establishments. The 23.0 GWh (line 2, column 8) decrease in General Service sales is due to the combination of low provincial GDP forecasts and the impact of energy efficiency programs which decrease sales by 17 GWh.

INDUSTRIAL DISTRIBUTION

The Industrial Distribution classification includes customers supplied from the distribution system and involved in the extraction of raw materials or in the manufacturing and processing of goods. The 56.8 GWh (line 3, column 8) decrease in Industrial Distribution budgeted sales reflects recent growth trends.

INDUSTRIAL TRANSMISSION

Industrial Transmission includes customers involved in the extraction of raw materials or in the manufacturing and processing of goods and are generally larger than those supplied from the distribution system. The 719.3 GWh (line 4, column 8) increase is mainly due to increases in sales forecasts reflecting recent operations of customers and product mix changes.

INDUSTRIAL INTERRUPTIBLE

Industrial Interruptible is comprised of eleven Industrial Transmission customers who purchase a portion of their energy requirements as Interruptible or Surplus energy and are subjected to curtailment of this load upon ten minute notice. The 403.3 GWh (line 5, column 8) decrease in sales reflects recent operations of customers and product mix changes.

WHOLESALE

The Wholesale class includes energy sales to two municipal utilities, Saint John Energy and Edmundston Energy. This class is comprised of Residential, General Service and Industrial Distribution customers located within these service territories. The 151.9 GWh (line 6, Column 8) decrease in Wholesale sales is mainly the result of natural growth being offset by decreased sales to Saint John Energy once the Burchill Wind Project is operational.

NON-METERED

The Non-metered sales budget, which include streetlights and other miscellaneous unmetered services, is forecast to decrease by 1.8 GWh (line 7, Column 8), to better align with recent actuals.

**BREAKDOWN OF REVENUE VARIANCE**

To better understand the reasons for changes in revenue, the effects of load and price (average unit rate) are separated. Table 4.1.3 provides a calculated average breakdown of the year-over-year revenue variance (2023/24 budget compared to the 2022/23 NB Power Board approved budget).

**Table 4.1.3**

**Breakdown of Revenue Variance**

Fiscal Year 2023/24B - 2022/23B

(in millions $)

| | | (1) | (2) | (3) |
|---|---|---|---|---|
| | | Variance due to Load Changes | Variance due to Price (Unit Rate) Changes | Total Variance |
| (1) | Residential | $ 27.0 | $ 64.7 | $ 91.7 |
| (2) | General Service | (3.1) | 29.7 | 26.6 |
| (3) | Industrial Distribution | (5.9) | 13.6 | 7.7 |
| (4) | Industrial Transmission | 57.4 | 23.1 | 80.5 |
| (5) | Industrial Interruptible | (20.5) | 25.9 | 5.4 |
| (6) | Wholesale | (15.2) | 9.9 | (5.3) |
| (7) | Sub-Total | $ 39.8 | $ 166.9 | $ 206.7 |
| (8) | Non-metered* | 0.2 | 2.7 | 2.8 |
| (9) | Rate Rider Adjustment Factor | | | $ 7.9 |
| (10) | Total | | | $ 217.4 |

*Non-metered sales revenue is based on the size and number of lights installed.

**Variance 1 (Table 4.1.3) Increase of $217.4 million – Line 10, Column 3 (2023/24B vs 2022/23B)**

As indicated above, $166.9 million (Table 4.1.3, line 7, column 2) plus $2.7 million (Table 4.1.3, line 8, column 2) of the 2023/24 budgeted revenue increase is attributable to the budgeted increase in unit prices. Increased sales result in revenue increases of $39.8 million (Table 4.1.3, line 7, column 1) to metered classes, and an additional $0.2 million (Table 4.1.3, line 8, column 3) to non-metered classes. The Rate Rider Adjustment Factor increases revenue by $7.9 million, which is offset by adjustments to the regulatory balances (Table 3.6.7, line 3 and Table 3.6.8, line 3).

The proposed 8.9 per cent rate increase to in-province sales of power effective April 1, 2023 accounts for $143.8 (Table 4.1.3, line 7 plus line 8 less line 5, column 2) of the price variance. The interruptible price variance accounts for $25.9 million increase in revenue (Table 4.1.3, line 5, column 2) resulting from higher fuel and purchased power prices for the energy used to supply interruptible load. Interruptible energy price is based in NB Power's incremental average cost of supply, plus the applicable on-peak/off-peak adder. Interruptible revenue is not impacted by general rate increases.

Table 4.1.4 below shows the unit rates for the 2023/24 budget, and the comparative years, based on an April 1, 2023 8.9% average rate increase. Note that the impact of the Rate Rider Adjustment Factor is not included in Table 4.1.4.

**Table 4.1.4**
**NB Power Corporation**
**Unit Rates**
Fiscal Years Ending March 31
($ per MWh)

| | | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6) - (7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Residential | $ 146.34 | $ 134.28 | $ 134.54 | $ 130.72 | $ 131.85 | $ 129.62 | $ 131.67 | $ 11.80 | $ (0.26) | $ (1.14) | $ (2.05) |
| (2) | General Service | 147.58 | 135.07 | 134.64 | 131.73 | 133.12 | 128.34 | 132.61 | 12.94 | 0.42 | (1.39) | (4.27) |
| (3) | Industrial Distribution | 121.21 | 110.06 | 103.37 | 105.25 | 106.54 | 100.39 | 106.64 | 17.84 | 6.69 | (1.29) | (6.25) |
| (4) | Industrial Transmission | 86.43 | 79.90 | 79.83 | 78.29 | 78.10 | 77.89 | 77.94 | 6.59 | 0.07 | 0.19 | (0.05) |
| (5) | Industrial Interruptible | 85.31 | 128.32 | 50.72 | 82.33 | 41.72 | 48.79 | 50.81 | 34.59 | 77.60 | 40.61 | (2.01) |
| (6) | Wholesale | 109.39 | 100.03 | 100.21 | 98.28 | 97.94 | 96.62 | 98.36 | 9.18 | (0.19) | 0.34 | (1.75) |
| (7) | **Weighted average unit rate** | $ 125.55 | $ 119.19 | $ 112.81 | $ 113.23 | $ 111.17 | $ 109.68 | $ 112.51 | $ 12.74 | $ 6.37 | $ (0.42) | $ 2.06 |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 4.1.4) Increase of $12.74/MWh – Line 7, Column 8 (2023/24B vs 2022/23/B)**

The average unit rate is budgeted to increase by $12.74/MWh (Table 4.1.4, line 7, Column 8) in the 2023/24 budget mainly due to the April 1, 2023, 8.9 per cent rate increase. The Interruptible unit rate increase of $34.59/MWh (Table 4.1.4, line 5, Column 8) is due to supply price increases in the 2023/24 budget.

## LOAD FORECAST DEVELOPMENT

The in-province energy sales volume in Table 4.1.2 is based on the 2023/2033 Load Forecast found in Appendix AD i. 2023 to 2033 Load Forecast. Each year, a load forecast is prepared based on a cause and effect analysis of past loads and trends. The analysis uses data gathered through customer surveys along with assessments of economic, demographic, technological and other factors that will affect the utilization of electrical energy. The full load forecast report includes details on forecast assumptions, methodology and results.

The load forecast is the basis of the revenue forecast. In the Board Decision from Matter 458, 2020/21 NB Power GRA dated October 2, 2020, the Board accepted the load forecast methods and results including the adoption of a 20-year rolling average as the basis for "normal" weather in future load forecasts.

## REVENUE FORECAST DEVELOPMENT

The basis of the 2023/24 revenue budget is the first year of the 2023-2033 Load Forecast found in Appendix AD i. 2023 to 2033 Load Forecast. Revenue is estimated from the sales of power for each customer class using unit rate trend analysis, applying the associated rates to the billing determinant estimates or a combination of both. The revenue forecast model which provides monthly revenue with all calculations related to energy sales and revenue broken down by customer class and by month for the test year at proposed rates can be found in Appendix AZ Revenue Forecast Model [4]. The following describes the process used to estimate revenue for each class.

[4] This addresses Minimum Filing Requirement 78.

Residential

The Residential sales budget is subdivided into billing components to estimate service charge revenue and energy sales using the appropriate rate from the rate schedule.

- Service charge revenue is calculated by multiplying the rate by the number of forecasted customers times twelve for the number of months in a year.
- Total energy is multiplied by the flat energy charge.

The addition of each billing component forms the total revenue budget. The resulting unit rate is then compared to the moving 12-month unit rate on a weather adjusted basis to verify the billing determinant based calculation.

General Service

The General Service sales budget is first subdivided into General Service I or II and then further subdivided by billing component (i.e. service charge, demand charge and energy charges). Service charge, demand charge and energy charge revenue are estimated using the estimated billing determinant for each charge and the corresponding rate from the rate schedule.

- Service charge revenue is calculated by multiplying the rate by the number of forecasted customers times twelve for the number of months in a year.
- Demand revenue is estimated by converting energy to billing demand using a historical factor and then multiplying by the applicable demand rate.
- Energy revenue is estimated using budgeted energy sales segmented into expected sales at the first and end energy blocks. The energy in each of these blocks is then multiplied by the applicable rate.

The addition of each billing component forms the total revenue budget. The resulting unit rate is then compared to the moving 12-month unit rate on a weather adjusted basis to verify the billing determinant based calculation.

Industrial Distribution

The Industrial Distribution sales budget is first subdivided into Small Industrial and Large Industrial and then further subdivided by billing component (i.e., demand charge and energy charges). Demand charge and energy charge revenue are estimated using the estimated billing determinant for each charge and the corresponding rate from the rate schedule.

- Demand revenue is estimated by converting energy to billing demand using a historical factor and then multiplying by the applicable demand rate.
- Energy revenue is estimated using budgeted energy sales segmented into expected sales at the first and end energy blocks. The energy in each of these blocks is then multiplied by the applicable rate.

The addition of each billing component forms the total revenue budget. The resulting unit rate is then compared to the moving 12-month unit rate to verify the billing determinant based calculation.

Industrial Transmission

For Industrial Transmission, a monthly revenue budget is calculated for each of these customers using the budgeted billing determinants of each. The sum of demand charges and revenue from firm energy sales (minus Curtailable Credits and Declining Discounts where applicable) forms the revenue budget for each customer. The revenue budget for each customer is summed to estimate the total Industrial Transmission budget.

Industrial Interruptible/Surplus

The basis of the Interruptible/Surplus revenue budget is the monthly incremental cost of supplying this load. Total monthly energy sales are separated into on and off peak based on historical sales patterns. This energy is then multiplied by the applicable incremental cost plus the respective $9.00/MWh or $3.00/MWh on/off-peak adder.

Wholesale

The Wholesale sales budget is subdivided by billing component (i.e., demand charge and energy charges). Demand charge and energy charge revenue are estimated using the estimated billing determinant for each charge and the corresponding rate from the rate schedule.

- Demand revenue is estimated by multiplying billing demand by the applicable demand rate.
- Energy revenue is estimated by multiplying energy by the applicable rate.

The addition of each billing component forms the total revenue budget. The resulting unit rate is then compared to the moving 12-month unit rate on a weather adjusted basis to verify the billing determinant based calculation.

Non-metered

Non-metered energy sales are first subdivided into streetlights and other miscellaneous unmetered services and then multiplied by the applicable expected unit rate to calculate revenue, which is compared to the moving 12-month unit rate and current revenue trends to verify the reasonableness of the estimate.

## 4.2 OUT–OF–PROVINCE SALES & GROSS MARGIN[1]

New Brunswick Energy Marketing Corporation ("NB Energy Marketing") and NB Power have entered into a Supply and Services Agreement under which NB Power agrees to make all surplus energy (surplus to in-province needs) available to NB Energy Marketing for purposes of fulfilling the mandate of NB Energy Marketing to export energy from New Brunswick. NB Energy Marketing provides NB Power with services under the Agreement, including the economic optimization of the generation dispatch of NB Power to meet both in-province load as well as the export commitments of NB Energy Marketing.

NB Energy Marketing also purchases energy on its own account for purposes of serving its export obligations where those purchases are more economic than utilizing the generation resources of NB Power. Effectively, a single dispatch of all resources is performed to ensure the most economic dispatch to meet both in-province and export load.

The transactions are governed by the Financial Risk Management Policies of NB Energy Marketing that have been approved by the Board. Refer to Section 8.0 Financial Risk Management Policy Updates for further information on NB Power's and NB Energy Marketing's financial risk management policies and certain changes for which approval of the Board is being sought.

NB Energy Marketing sells energy in the real time, day-ahead and month-ahead markets. It also enters into longer-term sales agreements to provide both capacity and energy where a net benefit can be achieved by supplying those longer term commitments either through NB Power surplus energy or through market purchases. PROMOD is used to simulate the forecasted economic dispatch and energy trading functions of NB Energy Marketing.

Through compliance with the Financial Risk Management Policies, NB Energy Marketing's objective is to preserve its margin on longer-term agreements by a combination of hedging

[1] This section addresses Minimum Filing Requirements 82, 83 and 84.

foreign exchange, fuel prices, and forward energy prices, or by securing longer-term purchases at fixed prices to match the term of the supply commitment.

NB Energy Marketing also engages in the sale of Renewable Energy Credits where markets for the sale of such credits exist. These sales are based on NB Energy Marketing's contractual rights to ownership of the environmental attributes of wind energy that is resold into US markets. NB Power's Board of Directors approved a Renewable Energy Certificate Policy in November 2021. Refer to Section 8.0 Financial Risk Management Policy Updates for information on this new policy for which approval of the Board is being sought.

Out-of-province revenue and gross margins are subject to:

- availability of NB Power generation resources, based on in-province energy requirements and planned unit generator maintenance schedules
- availability of interconnection purchases
- market prices
- fuel prices
- foreign exchange rates
- availability of export sales contracts and competition for these contracts

Out-of-province revenue also includes revenue received by NB Power under a long-term participation agreement with Maritime Electric Company, Limited ("Maritime Electric") whereby Maritime Electric is entitled to receive a percentage of the output from the PLNGS and pays their pro rata share of the costs of operating and maintaining the station.

Table 4.2.1 below presents details of out-of-province sales & gross margin. Firm energy includes export sales currently under contract and sales resulting from the anticipated retention of some or all of those contracts. Opportunity sales occur when excess generation is available to be sold at a margin in the markets. Capacity revenue results from the commitment of generation capacity in other regions on a cost per kW/month basis and has no associated energy volume.

Please refer to Appendix CONF B, Export Sales Confidential[2] for further information. This information is being filed under the Board's Policy on Confidentiality.

[2] This section addresses Minimum Filing Requirements 82 and 84.

**Table 4.2.1**

**NB Power Corporation**
**Out-of-Province Sales & Gross Margin**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1.0) | Firm Energy | 308.4 | 619.8 | 155.6 | 380.1 | 248.7 | 293.8 | 157.9 | 152.8 | 464.2 | 131.4 | 136.0 |
| (1.1) | Opportunity | 148.8 | 274.6 | 62.6 | 163.9 | 35.1 | 62.2 | 23.6 | 86.2 | 212.0 | 128.9 | 38.6 |
| (1.2) | Capacity | 15.4 | 17.1 | 16.9 | 13.7 | 12.8 | 12.2 | 14.2 | (1.5) | 0.2 | 0.9 | (2.0) |
| (2) | **Out-of-province sales of power** | $ 472.6 | $ 911.6 | $ 235.1 | $ 557.8 | $ 296.6 | $ 368.3 | $ 195.7 | $ 237.5 | $ 676.4 | $ 261.2 | $ 172.6 |
| (3) | Out-of-province fuel and purchased power costs | 409.9 | 827.6 | 135.4 | 429.5 | 198.4 | 254.7 | 125.7 | 274.4 | 692.2 | 231.1 | 128.9 |
| (4) | **Export gross margin** | **$ 62.7** | **$ 84.0** | **$ 99.7** | **$ 128.3** | **$ 98.2** | **$ 113.6** | **$ 70.0** | **(37.0)** | **(15.8)** | **$ 30.1** | **$ 43.6** |
| (5) | **Volumes (GWh)** | | | | | | | | | | | |
| (6.0) | Firm Energy | 3,173 | 4,725 | 1,919 | 4,296 | 1,892 | 3,580 | 2,177 | 1,253 | 2,806 | 2,404 | 1,404 |
| (6.1) | Opportunity | 1,158 | 1,263 | 867 | 1,879 | 402 | 997 | 329 | 0.3 | 396 | 1,477 | 668 |
| (7) | **Out-of-province sales volume** | **4,330** | **5,988** | **2,786** | **6,175** | **2,294** | **4,577** | **2,505** | **1,544** | **3,201** | **3,880** | **2,072** |

Note to reader: Financial tables reflect differences due to rounding

**Variance 1 (Table 4.2.1) – increase of $237.5 million – Line 2, column 8 (2023/24B vs 2022/23B)** [3]

Out-of-province sales are budgeted to be $472.6 million (line 2, column 1) in 2023/24, an increase of $237.5 million (line 2, column 8) compared to the 2022/23 NB Power Board approved budget.

The major factors contributing to this variance are explained below. Variances included are inclusive of foreign exchange impacts.

- Higher firm sales due to new load forecasts at higher prices increases sales revenue by $152.8 million
- New opportunity sales at higher prices will result in an increase of $86.2 million..

Offset by:

- Lower expected capacity sales of $1.5 million.

[3] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

## 4.3 MISCELLANEOUS REVENUE[1]

Miscellaneous revenue is budgeted to be $92.3 million in 2023/24 (Table 4.3.1, line 8, column 1). Please refer to the table and categories below for the variance from the 2023/24 budget to the 2022/23 budget.

**Table 4.3.1**

**NB Power Corporation**
**Miscellaneous Revenue**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6) - (7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Customer related revenues | $ 10.5 | $ 9.9 | $ 9.9 | $ 9.4 | $ 9.9 | $ 4.9 | $ 9.9 | $ 0.6 | $ 0.0 | $ (0.5) | $ (5.0) |
| (2) | Water heater rentals | 27.1 | 23.6 | 23.4 | 22.9 | 22.6 | 22.3 | 23.1 | 3.7 | 0.3 | 0.3 | (0.8) |
| (3) | Other revenues | 25.0 | 26.1 | 24.9 | 30.4 | 21.8 | 24.1 | 27.3 | 0.1 | 1.1 | 8.5 | (3.2) |
| (4) | Pole attachments | 4.8 | 4.1 | 4.1 | 4.2 | 4.1 | 4.1 | 3.8 | 0.8 | 0.0 | 0.2 | 0.2 |
| (5) | Transmission rights resale | 1.0 | 2.0 | 1.4 | 1.7 | 2.1 | 2.0 | 7.9 | (0.4) | 0.6 | (0.3) | (5.9) |
| (6) | Net Transmission revenues | 18.7 | 15.7 | 17.3 | 15.9 | 14.8 | 12.9 | 15.5 | 1.5 | (1.6) | 1.1 | (2.6) |
| (7) | Sale of Natural Gas | 5.2 | 36.5 | - | 53.6 | - | 0.2 | - | 5.2 | 36.5 | 53.6 | 0.2 |
| (8) | **Total miscellaneous revenue** | $ 92.3 | $ 117.8 | $ 80.9 | $ 138.2 | $ 75.3 | $ 70.5 | $ 87.6 | $ 11.4 | $ 36.9 | $ 62.9 | $ (17.1) |

Note to reader: Financial tables reflect differences due to rounding

[1] This section addresses Minimum Filing Requirements 85 and 86.

CUSTOMER RELATED REVENUES

Customer related revenue includes fees charged to customers for all initial service connections, reconnections and service call fees on the distribution system, surcharges and late payment charges on overdue accounts, and facilities rental revenue related to industrial customers who rent substation facilities.

**Variance 1 (Table 4.3.1) Increase of $0.6 million - Line 1, Column 8 (2023/24B vs 2022/23B)** [2]

Customer related revenues are budgeted to be $10.5 million (line 1, column 1) in the 2023/24 budget, an increase of $0.6 million (line 1, column 8) from the 2022/23 budget (line 1, column 3). The increase is primarily associated with the new rate for the Service Call Fee (RSP O-1) that has been proposed to recover the cost associated with delivering this service. Increases were also made to surcharge and facilities equipment rental revenues based on trending of actuals and the requested 8.9 per cent rate increase.

In reviewing the Service Call Fee (RSP O-1), NB Power examined the cost of delivering the service, including travel time, the labour required to provide the service, the vehicle costs, and the overhead cost. Based on the Service Call Fee Rate Analysis (Appendix AA), NB Power is requesting a rate of $61.54 compared to the current rate of $50.43.

WATER HEATER RENTALS

NB Power offers a 24/7 water heater rental service to its customers in exchange for a monthly fee. Approximately 70 per cent of NB Power’s residential customers and 30 per cent of commercial customers choose this service.

NB Power’s current rental fees, as summarized in the table below, are the lowest in Canada indicating high value for the customers who choose the rental service.

[2] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

## Water Heater Rental Rate Comparison

| Company | 40 Gallon Rate | 60 Gallon Rate |
|---|---|---|
| Brantford Hydro | $13.95 | $14.95 |
| DeMark Home | $12.49 | $13.99 |
| EnerCare | $14.49 | $16.51 |
| Hydro Solutions | $12.99 | $13.99 |
| NB Power | $7.06 | $9.16 |
| Reliance Home Comfort | $14.71 | $17.27 |
| Saint John Energy | $11.78 | $16.51 |
| Utilities Kingston | $13.54 | $15.09 |

Unprecedented global supply constraints have resulted in significant cost increases for raw materials, such as steel, copper, and foam, needed to manufacture water heaters. As a result, the price of water heaters has increased by approximately 45 per cent compared to pre-pandemic pricing. Plumbing contractors are also experiencing increased costs due to skilled labour shortages and inflationary pressures on materials and fuels. Cost increases exceeding 25 per cent, are being reflected in competitive bid submissions as plumbing services are retendered. As a result, NB Power is requesting a $1 per month increase to water heating rental fees (an average increase of 13.5 per cent).

**Variance 1 (Table 4.3.1) Increase of $3.7 million - Line 2, Column 8 (2023/24B vs 2022/23B)**

Water heater rental revenue is budgeted to be $27.1 million (line 2, column 1) in the 2023/24 budget, an increase of $3.7 million (line 2, Column 8) from the 2022/23 budget. This increase results from both a rate increase and growth; $3.1 million relates to a $1 per month increase to water heating rental fees or an average increase of 13.5 per cent, and $0.6 million relates to growth.

Table 4.3.2 below summarizes the historical and forecasted capital investments and OM&A expenditures for the water heating rental program.

**Table 4.3.2**

**NB Power Corporation**
**Water Heater Expenditures**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Capital | $ 12.5 | $ 12.6 | $ 12.0 | $ 12.5 | $ 9.7 | $ 9.2 | $ 7.6 | $ 0.5 | $ 0.6 | $ 2.8 | $ 1.5 |
| (2) | OM&A | $ 3.4 | $ 2.6 | $ 2.6 | $ 2.7 | $ 3.4 | $ 3.3 | $ 4.5 | $ 0.8 | $ (0.0) | $ (0.6) | $ (1.2) |
| (3) | Total Expenditures | $ 15.9 | $ 15.2 | $ 14.6 | $ 15.3 | $ 13.1 | $ 12.4 | $ 12.1 | $ 1.2 | $ 0.6 | $ 2.2 | $ 0.3 |

Note to reader: Financial tables reflect differences due to rounding

The 2023/24 water heater expenditures are $1.2 million higher than the 2022/23 budget (line 3, column 8). The higher capital expenditures of $0.5 million (line 1, column 8) reflects the current cost of water heaters that was not fully reflected in the 2022/23 budget. The higher OM&A expenditures of $0.8 million (line 2, column 8) are mainly due to cost increases for plumbing services that will be retendered.

To further illustrate the trajectory of costs, the 2023/24 budget for total expenditures (line 3, column 1) is $3.5 million higher than pre-pandemic 2020/21 actuals (line 3, column 6). Over this period, average installed unit cost for a water heater escalated from $599.90 in 2020/21 to $781.25 in 2023/24, which is a 30 percent increase. This variance reflects the overall increased investment needed to sustain the financial health of the water heating program and program revenues in excess of costs that are used to lower electricity rates for NB Power's customers. To help offset these cost pressures, NB Power works with plumbing contractors to execute on the two one-year mutually agreed upon contract extensions at existing prices to avoid higher prices if retendered.

OTHER REVENUES

Other revenues include items such as: tree trimming services, distribution detailing services, gains on the sale of surplus assets and scrap, other rental property, customer contributions and other miscellaneous third party work.

**Variance 1 (Table 4.3.1) Increase of $0.1 million - Line 3, Column 8 (2023/24B vs 2022/23B)**

Other revenue is budgeted to be $25.0 million (line 3, column 1) in the 2023/24 budget, an increase of $0.1 million (line 3, Column 8) from the 2022/23 budget.

POLE ATTACHMENTS

Pole attachments revenue is generated from third party attachments to distribution poles.

**Variance 1 (Table 4.3.1) Increase of $0.8 million - Line 4, Column 8, (2023/24B vs 2022/23B)**

Pole attachment revenues are budgeted to be $4.8 million (line 4, column 1) in the 2023/24 budget, an increase of $0.8 million (line 4, Column 8) from the 2022/23 budget. The increase is based on actual pole attachment billings trending as well as an escalation associated with the current proposed rate increase.

TRANSMISSION RIGHTS RESALE

Transmission rights resale revenue is generated by NB Power when NB Power transfers certain point to point transmission reservation rights to third parties.

**Variance 1 (Table 4.3.1) Decrease of $ 0.4 million - Line 5, Column 8 (2023/24B vs 2022/23B)**

Transmission rights resale revenue is budgeted to be $1.0 million (line 5, column 1) in the 2023/24 budget, an decrease of $0.4 million (line 5, Column 8) from the 2022/23 budget. NB Power is expecting lower opportunities to resell transmission capacity to neighboring utilities looking to wheel energy through New Brunswick due to increased exports sales from NB Power to ISO New England, thus reducing the available capacity that can be resold.

NET TRANSMISSION REVENUE

Net transmission revenue reflects net revenues recoverable from third parties related to the various schedules under the New Brunswick Open Access Transmission Tariff. For the purposes of calculating transmission revenue impacts, the revenues in the 2022/23 budget and 2023/24 test year assume that the rates for the various schedules proposed in Matter 513 have been approved by the EUB.

**Variance 1 (Table 4.3.1) Increase of $1.5 million - Line 6, Column 8, (2023/24B vs 2022/23B)**

Net transmission revenue is budgeted to be $18.7 million (line 6, column 1) in the 2023/24 budget, an increase of $1.5 million from the 2022/23 budget. The increase is mainly due to an expected increase in the volume of short-term point-to-point reservations based on trending.

SALE OF NATURAL GAS

Natural gas sales occur when committed volumes of natural gas are unable to be consumed at the Bayside Generating station. This usually only occurs during outages (planned or forced) at the Bayside Generating station. The margin from the sale of natural gas is recorded in Miscellaneous Revenue.

**Variance 1 (Table 4.3.1) Increase of $5.2 million - Line 7, Column 8, (2023/24B vs 2022/23B)**

Sale of natural gas revenue is budgeted to be $5.2 million (line 7, column 1) in the 2023/24 budget, an increase of $5.2 million from the 2022/23 budget. The increase is mainly due to the expected maintenance outage in the fall of 2023 at the Bayside generating station.

# 5.0 ASSETS AND CAPITAL EXPENDITURES

## 5.1 CAPITAL PLANNING PROCESS[1]

NB Power's Investment Governance Framework includes review committees at both the corporate and divisional level, known respectively as the Investment Management Committee ("IMC") and the Investment Review Committee ("IRC"). A recent refresh of the investment governance framework led to the creation of a new Corporate level committee that is comprised of key representatives from the individual divisional committees. It is known as the Joint Investment Review Committee ("Joint IRC") and its primary mandate is to collaborate among all divisions to ensure appropriate and consistent prioritization of capital investments for the long-term sustainability of the Corporation's capital infrastructure, as well as, considering the most value to the Corporation and our customers. This committee recommends the annual capital plan to the IMC. The IMC approves the capital portfolio for inclusion in the budget.

The refresh of the Investment Governance Framework took place in 2021/22 and was rolled out in Spring 2022 for utilization in preparing the 2023/24 budget. It included updates to the investment rationale document and project scoring matrix. Included in the refresh was the addition of OM&A initiatives planning. Please refer to Section 3.2 OM&A Expense for further information. Please refer to Appendix AE i. – NB Power Investment Governance Framework for the updated Framework document.

At the Divisional level, the IRC determines which projects within the division should be put forward for prioritization. Each Division has an internal process for identifying potential projects. Planning criteria include forecasted future load growth, specific requirements from customers, safety concerns, aging infrastructure, upgrade requirements, regulatory commitments, as well as inspection and condition assessment results. Each IRC is then responsible for vetting and prioritizing capital submissions in their respective areas. All IRCs use the same investment rationale template, project scoring matrix and prioritization tool to ensure capital projects are evaluated consistently as the divisions compete for a limited capital spending envelope. Capital projects are evaluated on both financial and non-financial criteria and the final decision on each specific project is based on an overall assessment of costs and benefits, evaluation of risk, and how each project ranks against the others within the portfolio.

Major projects and programs have executive oversight committees that are responsible for establishing the strategic direction, business case review, and the on-going monitoring of project progress.

Historically, planning and forecasting in the utility industry has had many material uncertainties. Several of the underlying assumptions are subject to changes beyond management's control. Every year, management is faced with new pressures relating to ongoing capital infrastructure requirements, inflation, and opportunities due to changing markets and technologies, and as a result must be strategic in limiting these cost pressures. However, the current planning cycle has proven to be particularly difficult due to significant global factors including exceptional inflationary pressures and the supply chain crisis. This involves reducing spending in some areas to offset new pressures. Management has gone to great lengths to mitigate cost pressures in the near term within the capital portfolio**.** The proposed capital budgets put forward by the IRCs to the JIRC and IMC saw substantial cuts as management sought to prioritize planned work and manage cost pressures from inflation and supply chain disruptions, while balancing reliability and obligations to our customers. The committees took a risk-based approach in the review and decision-making of the reductions. This included the removal of $54.2 million in capital expenditures and $18.5 million of planned work within OM&A. Capital reductions included postponing generating station capital upgrades, adjustments to the receipt of AMI meters, delay in vehicle replacement purchases (partially offset by higher vehicle maintenance costs of the aging

[1] This section describes the capital planning process and addresses Minimum Filing Requirements 90 and 91.

fleet) and scaling back planned work in programs, including pole top transformers and transformer replacements.

## 5.2 CAPITAL PROJECTS[1]

CAPITAL EXPENDITURES

A capital expenditure is a cash outlay that is expected to generate future economic benefit. An expenditure is considered capital if it exceeds relevant materiality limits and meets one or more of the following criteria:

- has a service life greater than one year or extends the life of an existing asset
- increases the quantity of output or improves the quality of the output
- reduces associated operating costs

The cost of additions to property, plant and equipment is the original cost of contracted services, direct labour and material, vehicle allocation, interest during construction ("IDC") and overhead (based on overhead rates). The IDC is capitalized monthly based on the cost of long-term borrowings. Capital expenditures remain in Work in Progress until the capital asset becomes available for use. Portions of capital expenditures for a given year may carry over to another fiscal year and be capitalized as fixed asset additions at that time. Once charged to fixed assets, depreciation begins to be calculated on the assets.

Overhead is applied to all capital projects and is intended to allocate support costs from departments that do not charge directly to capital. The overhead rate is applied to the total monthly project spending in the month (before IDC). NB Power internal staff conducted a review of the overhead rates in fiscal 2017/18 based on the same methodology applied by KPMG in prior updates. These rates, adjusted for CPI, have been applied to the 2023/24 budget. Overhead rates are meant to capitalize a predetermined dollar amount of support costs and therefore the rates will be reset annually based on the divisional capital budgets.

The budgeted IDC rate is 4.29 per cent for each division except Transmission. Transmission's rate is 6.29 per cent because it reflects an allowance for funds used during

[1] This section addresses Minimum Filing Requirements 91, 92, 93, 94, 95 and 96.

construction for the equity component of the deemed capital structure. IDC is calculated on the previous month work-in-progress balance for projects longer than six months in duration.

MATERIALITY LIMITS

NB Power capitalizes expenditures of a specified dollar value that have an asset life greater than one year. A minimum specified dollar amount has been assigned to each asset class to define assets which meet the criteria. Materiality limits are reviewed by the Amortization Review Committee on a periodic basis. The following table identifies these materiality levels.

| Asset Category | Materiality Limit |
|---|---|
| Power Generating Stations | $150,000 |
| Terminals | $10,000 |
| Feeder & Industrial Load Substations | $5,000 |
| Transmission System | $10,000 |
| Land & Buildings | $10,000 |
| Communications Equipment | $5,000 |
| Tools | $5,000 |
| Computer Equipment | $5,000 |
| Computer software | $250,000 |
| Distribution | $200 & Considered an Asset/WO |
| Motor Vehicles | $5,000 |
| Office Equipment | $5,000 |

The main categories of capital spending are: regular capital spending, which includes asset reliability, obligation to serve, and safety and regulatory; major capital projects including the Mactaquac Life Achievement project ("MLAP") and the Advanced Metering Infrastructure ("AMI") project; and major generation outage and inspection projects. For information on capital spending, please refer to Table 5.2.1.

2023/24 CAPITAL EXPENDITURES

Gross capital expenditures refers to the capital project spending (including the change in capital spares) prior to the application of funding sources including customer contributions and government grants. In 2023/24 the gross capital expenditures are budgeted at $400.5 million. Table 5.2.1 below summarizes the capital expenditures by category. A significant portion of the planned expenditures is allocated towards sustainment of the existing infrastructure and involves the replacement or overhaul of assets within Generation, Transmission, and Distribution (i.e. asset reliability and major outage & inspection). A relatively smaller portion of the planned spending is allocated towards expansion of the core business within Distribution and Transmission driven by customer demand (within obligation to serve). In addition, a portion of the budget includes spending on growth of the business to address opportunities and challenges that require fundamental changes in the way NB Power operates and provides energy to its customers (i.e., asset optimization/productivity).

Areas of significant capital expenditures in 2023/24B include:

- $115.0 million within PLNGS and conventional Generation to maintain asset reliability, life extension of some existing assets and adherence to safety and regulatory compliance requirements
- $91.5 million in Distribution and Transmission asset reliability projects, including several transmission line life extension projects
- $65.5 million within the major projects category which includes AMI and MLAP
- $62.2 million in investments in major outage and inspection projects within PLNGS and conventional generation
- $43.6 million in Obligation to Serve projects within Transmission and Distribution

A detailed listing of capital projects can be found in Appendix O – Capital Spending Details FY24. This listing identifies the projects, aligned with the groupings included in Table 5.2.1, selected to meet the organization's investment needs through the process as outlined in Section 5.1 Capital Planning Process.[2]

[2] This appendix addresses Minimum Filing Requirement 91.

**Table 5.2.1**

**NB Power Corporation**
**Gross Capital Expenditures**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **(1.0)** | **Transmission & Distribution General** | | | | | | | | | | | |
| (1.1) | Asset Reliability (Transmission) | $ 56.9 | $ 38.9 | $ 38.9 | $ 49.8 | $ 47.9 | $ 36.3 | $ 40.9 | $ 17.9 | $ (0.0) | $ 1.8 | $ (4.6) |
| (1.2) | Asset Reliability (Distribution) | 34.6 | 26.9 | 34.8 | 21.0 | 39.9 | 25.2 | 39.3 | (0.2) | (7.9) | (18.9) | (14.0) |
| (1.3) | Obligation to Serve (Transmission) | 0.0 | 2.4 | (0.0) | 0.0 | 0.0 | 4.8 | - | 0.0 | 2.4 | 0.0 | 4.8 |
| (1.4) | Obligation to Serve (Distribution) | 43.6 | 45.6 | 45.5 | 49.5 | 41.4 | 43.5 | 40.7 | (2.0) | 0.1 | 8.1 | 2.8 |
| (1.5) | Safety & Regulatory Compliance (Transmission) | 1.1 | 1.0 | 1.0 | 1.1 | 1.2 | 0.7 | 0.9 | 0.2 | 0.0 | (0.0) | (0.2) |
| (1.6) | Safety & Regulatory Compliance (Distribution) | 7.5 | 3.4 | 2.8 | 5.6 | 6.4 | 4.3 | 5.7 | 4.7 | 0.6 | (0.8) | (1.4) |
| (1.7) | Asset Optimization/Productivity (Transmission) | - | 0.0 | (0.0) | 0.7 | 1.8 | 0.8 | 2.7 | 0.0 | 0.0 | (1.1) | (1.9) |
| (1.8) | Asset Optimization/Productivity (Distribution) | 5.8 | 5.2 | - | 6.1 | 0.4 | 0.0 | 0.0 | 5.8 | 5.2 | 5.6 | (0.0) |
| **(1.9)** | **Sub-Total Transmission & Distribution General** | **$ 149.5** | **$ 123.4** | **$ 123.0** | **$ 133.9** | **$ 139.1** | **$ 115.7** | **$ 130.2** | **$ 26.5** | **$ 0.4** | **$ (5.3)** | **$ (14.5)** |
| **(2.0)** | **Transmission & Distribution Major Projects** | | | | | | | | | | | |
| (2.1) | Advanced Metering Infrastructure | $ 31.7 | $ 5.6 | $ 19.9 | $ 11.2 | $ 20.6 | $ 8.1 | $ 23.3 | $ 11.8 | $ (14.3) | $ (9.4) | $ (15.1) |
| (2.2) | Smart Communities | - | 9.0 | 9.9 | 7.5 | 12.1 | 2.6 | 23.6 | (9.9) | (0.9) | (4.6) | (21.1) |
| **(2.3)** | **Sub-Total Transmission & Distribution Major Projects** | **$ 31.7** | **$ 14.6** | **$ 29.8** | **$ 18.7** | **$ 32.8** | **$ 10.7** | **$ 46.9** | **$ 1.9** | **$ (15.2)** | **$ (14.0)** | **$ (36.2)** |
| **(3.0)** | **Generation General** | | | | | | | | | | | |
| (3.1) | Nuclear Generation projects | $ 56.9 | $ 54.6 | $ 54.9 | $ 42.7 | $ 49.8 | $ 33.7 | $ 42.4 | $ 2.0 | $ (0.3) | $ (7.0) | $ (8.8) |
| (3.2) | Other Generation projects | 58.1 | 103.8 | 88.5 | 27.1 | 44.4 | 22.7 | 36.4 | (30.4) | 15.3 | (17.2) | (13.7) |
| (3.3) | Major Outage & Inspection (Nuclear) | 41.6 | 127.2 | 80.6 | 26.5 | 18.3 | 82.7 | 53.4 | (39.1) | 46.5 | 8.3 | 29.3 |
| (3.4) | Major Outage & Inspection (Generation) | 20.6 | 22.5 | 20.8 | 43.1 | 26.4 | 8.1 | 11.1 | (0.2) | 1.7 | 16.7 | (3.0) |
| **(3.5)** | **Sub-Total Generation General** | **$ 177.2** | **$ 308.0** | **$ 244.8** | **$ 139.5** | **$ 138.8** | **$ 147.2** | **$ 143.4** | **$ (67.6)** | **$ 63.2** | **$ 0.7** | **$ 3.8** |
| **(4.0)** | **Generation Major Project** | | | | | | | | | | | |
| (4.1) | Mactaquac Life Achievement | $ 33.8 | $ 29.5 | $ 24.4 | $ 29.8 | $ 24.3 | $ 18.2 | $ 19.2 | $ 9.5 | $ 5.1 | $ 5.4 | $ (1.1) |
| **(5.0)** | **Corporate Services** | $ 6.6 | $ 9.0 | $ 5.3 | $ 5.3 | $ 6.5 | $ 8.5 | $ 10.1 | $ 1.3 | $ 3.7 | $ (1.2) | $ (1.6) |
| **(6.0)** | **Change in Standby Equipment and Spare Parts** | $ 1.7 | $ 21.9 | $ 20.0 | $ 17.7 | $ 4.6 | $ 15.5 | $ 3.9 | $ (18.3) | $ 1.9 | $ 13.0 | $ 11.5 |
| **(7.0)** | **Total Gross Capital Expenditures** | **$ 400.5** | **$ 506.4** | **$ 447.3** | **$ 344.8** | **$ 346.1** | **$ 315.7** | **$ 353.8** | **$ (46.8)** | **$ 59.1** | **$ (1.3)** | **$ (38.0)** |

As previously stated, gross capital expenditures are budgeted to be $400.5 million in 2023/24 (Table 5.2.1, line 7, column 1), which is $46.8 million lower than the 2022/23 NB Power Board approved budget. A listing of 2023/24 Capital projects greater than $5 million can be found in Table 5.2.3., followed by details on each project.

The variance explanations for the 2023/24 budget compared to the 2022/23 NB Power Board approved budget are provided below.

TRANSMISSION & DISTRIBUTION GENERAL

**Variance 1 (Table 5.2.1) Increase of $26.5 million - Line 1.9, Column 8 (2023/24B vs 2022/23B)** [3]

Transmission & Distribution General is budgeted to be $149.5 million (line 1.9, column 1) in the 2023/24 budget, an increase of $26.5 million (line 1.9, column 8) from the 2022/23 NB Power Board approved budget. The increase is primarily related to the following:

- Higher Asset Reliability (Transmission) requirements ($17.9 million) related to the rebuild of the Eel River HVDC Station Synchronous Condenser unit 1, additional investment in the line life extension program due to ongoing aging and deterioration of the pole system and the new tie transformer for Eel River HVDC station
- Increase in Safety & Regulatory Compliance (Distribution) spend ($4.7 million) associated with the PCB management program of pole top transformers
- Higher Asset Optimization/Productivity (Distribution) investment ($5.8 million) related to the Advanced Distribution Management System (“ADMS”) project

TRANSMISSION & DISTRIBUTION MAJOR PROJECTS

**Variance 1 (Table 5.2.1) Increase of $1.9 million - Line 2.3, Column 8 (2023/24B vs 2022/23B)**

Transmission & Distribution Major Projects is budgeted to be $31.7 million (line 2.3, column 1) in the 2023/24 budget, an increase of $1.9 million (line 2.3, column 8) from the 2022/23 NB

[3] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

Power Board approved budget. This increase is related to mass meter deployment beginning within the AMI project, partially offset by no planned spending for Smart Communities because the capital portion of the project will be complete in 2022/23.

GENERATION GENERAL

**Variance 1 (Table 5.2.1) Decrease of $67.6 million - Line 3.5, Column 8 (2023/24B vs 2022/23B)**

Generation General is budgeted to be $177.2 million (line 3.5, column 1) in the 2023/24 budget, a decrease of $67.6 million (line 3.5, column 8) from the 2022/23 NB Power Board approved budget.

The decrease is primarily related to :

- Decrease in planned project spending on the Bayside Generating Station in the 2023/24 budget compared to the 2022/23 budget which included the Bayside Gas Turbine project - $40.3 million
- Lower spending on major outages and inspections - $39.3 million
- Tobique Generating Station Unit 2 Life Extension in 2022/23B - $11.2 million

Partially offset by increases in other areas, including

- Millbank Generating Station projects, primarily pre-work for future C Inspections - $8.2 million
- Coleson Cove Generating Station projects – various - $6.3 million
- Mactaquac Generating Station Civil Infrastructure Refurbishment work - $4.3 million
- Various asset reliability projects - $2.4 million
- PLNGS regular projects - $2.0 million

GENERATION MAJOR PROJECT

**Variance 1 (Table 5.2.1) Increase of $9.5 million - Line 4.1, Column 8 (2023/24B vs 2022/23B)**

Generation Major Project – MLAP is budgeted to be $33.8 million (line 4.1, column 1) in the 2023/24 budget, an increase of $9.5 million (line 4.1, column 8) from the 2022/23 NB Power Board approved budget. The increase reflects different work requirements in 2023/24.

CORPORATE SERVICES

**Variance 1 (Table 5.2.1) Increase of $1.3 million - Line 5.0, Column 8 (2023/24B vs 2022/23B)**

Corporate Services is budgeted to be $6.6 million (line 5.0, column 1) in the 2023/24 budget, an increase of $1.3 million (line 5.0, column 8) the 2022/23 NB Power Board approved budget. The increase is mainly due to additional safety and regulatory projects such as physical access and cyber intrusion detection in 2023/24.

CHANGE IN STANDBY EQUIPMENT AND SPARE PARTS

**Variance 1 (Table 5.2.1) Decrease of $18.3 million - Line 6.0, Column 8 (2023/24B vs 2022/23B)**

Change in standby equipment and spare parts is budgeted to be $1.7 million (line 6.0, column 1) in the 2023/24 budget, a decrease of $18.3 million (line 6.0, column 8) from the 2022/23 NB Power Board approved budget. The decrease is primarily related to the timing of materials received and subsequently issued to capital projects, including the Eel River HVDC Station Synchronous Condenser project and the AMI project. This account can often be impacted when rebalancing the capital portfolio to meet financial targets whereby equipment received is placed in capital spares when project execution is delayed or deferred

POINT LEPREAU NUCLEAR GENERATING STATION (“PLNGS”) PERFORMANCE UPDATE

A significant capital expenditure in the 2023/24 budget is the PLNGS planned major inspection and overhaul work for Outage 2023 and Outage 2024. This is in support of the continued focus on plant and equipment reliability and is one of the main components of the key initiative to become top quartile within the industry.

PLNGS performance updates as it relates to planned outage expenditures are explained in the section below. Please refer to section 3.2 OM&A for additional information regarding OM&A spending in relation to station performance updates.

Planned Maintenance and Inspection Outages

Recurring major outage and inspection activities ("outages") at NB Power's generating stations are treated for accounting purposes as "projects". However, it is important to note that an outage "project" is an aggregation of a number of separate and distinct capital projects of various sizes and expense that are grouped together due to the requirement that the plant be shut down for the work to proceed.

The purpose of the planned maintenance and inspection outages is to maintain the station equipment life cycle and long-range plans to support the safe and reliable operation of PLNGS. Outage scope usually includes corrective orders, preventative maintenance activities, system or component health improvements, regulatory commitments, major component inspections, planned capital and plant modifications, and other significant labour and material work that cannot be performed during normal plant operation.

PLNGS has executed planned maintenance outages on an annual basis over the last several years with the exception of 2020/21. This strategy allows for a concentration on equipment reliability by addressing key deficiencies in a timely manner, as well as employing a more aggressive preventative maintenance strategy. In addition, PLNGS is working to optimize and align the preventive maintenance and inspection activities such that they can be implemented on a 24-month planned outage cycle allowing PLNGS to convert to a biennial planned maintenance outage schedule.

Table 5.2.2 below summarizes the duration and costs of PLNGS planned maintenance outages over the period 2020/21 to 2023/24. It is important to note that while duration of the outage is a factor influencing the cost of the outage, it is in fact the outage scope (components being worked on) that is the largest driver of the overall capital cost of the outage. PLNGS is in alignment with industry best practice by starting outage planning work well in advance of a planned outage start date.

**Table 5.2.2**

**NB Power Corporation**
**PLNGS Outage Spending**
Fiscal Years Ending March 31
(in millions $)

| | Component | Duration (Days) | Total | (1) 2023/24B | (2) 2022/23E | (3) 2021/22A | (4) 2020/21A |
|---|---|---|---|---|---|---|---|
| (1) | Outage 2024 | 56.0 | $ 24.5 | $ 21.5 | $ 2.5 | $ 0.5 | $ - |
| (2) | Outage 2023 | 22.0 | 23.3 | 20.1 | 3.2 | - | - |
| (3) | Outage 2022 | 109.0 | 152.1 | - | 121.5 | 26.5 | 4.1 |
| (4) | Outage 2020 | 62.0 | 78.2 | - | - | - | 78.2 |
| (5) | **PLNGS Outage Spending** | | $ 278.1 | $ 41.6 | $ 127.2 | $ 27.0 | $ 82.3 |

Note to reader: Financial tables reflect differences due to rounding.

Effective outage execution is a high priority for PLNGS from both a cost and safety perspective. The investments in planned maintenance outages that NB Power has undertaken in recent years have resulted in favourable outcomes. It is expected these continued efforts will enable PLNGS to meet its short and long-range performance targets.

Major inspection and overhauls can involve several components of the plant. The total planned capital spending for the upcoming 2023 outage is $23.3 million, with expenditures for pre-outage work being incurred in 2022/23 and the majority of costs being incurred early in the test year. Refer to Appendix Q i. Point Lepreau Nuclear Generating Station Outage 2023 for more detailed information.

2023/24 CAPITAL PROJECTS GREATER THAN $5 MILLION

Table 5.2.3 below provides a list of projects greater than $5 million in the test year by category[4]:

**Table 5.2.3**

**NB Power Corporation**
**Projects greater than $5 million 2023/24B**
(in millions $)

| | Component | Project Name | (1) 2023/24B |
|---|---|---|---|
| (1) | Generation Major Project | Mactaquac Life Achievement | $ 33.9 |
| (2) | Customer Service & Distribution Major Project | Advanced Metering Infrastructure | $ 31.7 |
| (3) | Transmission Asset Reliability | Line Life Extension Program | $ 23.0 |
| (4) | Major Outage and Inspection (Nuclear) | PLNGS 2024 Outage | $ 21.5 |
| (5) | Major Outage and Inspection (Nuclear) | PLNGS 2023 Outage | $ 20.1 |
| (6) | Major Outage and Inspection (Generation) | Belledune Generating Station Major Outage & Inspection | $ 10.6 |
| (7) | Transmission Asset Reliability | Eel River Synchronous Condenser Units | $ 10.8 |
| (8) | Major Outage and Inspection (Generation) | Coleson Cove Generating Station Unit 2 Major Outage & Inspection | $ 9.6 |
| (9) | Generation Asset Reliability | Mactaquac Civil Infrastructure Refurbishment | $ 5.4 |
| (10) | Customer Service & Distribution Asset Optimizatior | Advanced Distribution Management System | $ 5.1 |

Note to reader: Financial tables reflect differences due to rounding.

As outlined in Section 5.1 Capital Planning Process, the investment portfolio is developed and prepared such that it addresses key risk areas, obligation to serve requirements and key strategic priorities of the organization. The projects within the categories listed above were selected based upon their strategic importance to the company. During the investment governance prioritization process all projects brought forward that were greater than $5 million were approved; there were none that were not approved[5].

Below is a summary description of each capital project over $5 million[6].

Mactaquac Life Achievement ($33.9 million)

A major capital project during the 3-year plan period revolves around the future of Mactaquac. The current expected end of service life for the concrete structures at the Station with the ongoing maintenance program is approximately 2030 based on engineering

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[4] This table addresses Minimum Filing Requirement 93.
[5] This addresses Minimum Filing Requirement 94.
[6] This addresses Minimum filing Requirement 95.

estimates. The Station produces approximately 1.6 TWh annually and can produce 668 MW at full capacity.

Advanced Metering Infrastructure ($31.7 million)

NB Power continues to leverage technology advancements that will improve its ability to respond to changing customer expectations, address climate change, modernize the grid, and focus on continuous process improvement. New technologies such as Advanced Metering Infrastructure (AMI) will enable NB Power to improve its service to customers and help them better understand their electricity usage and use energy more wisely. AMI will help NB Power better manage the rising demand on the electricity system well into the future, while laying the groundwork for a wide range of new customer benefits.

The AMI project comprises the replacement of approximately 360,000 residential and commercial meters across the province with smart meters and supporting infrastructure. To date, NB Power has largely completed the installation and integration of the supporting infrastructure. Mass meter deployment was scheduled to begin in September 2022 but has been postponed due to supply chain issues affecting the delivery of smart meters. The on-going COVID-19 pandemic shutdowns in Asia and the current war in Ukraine have contributed to a worldwide shortage of semi-conductors, a key component required in a smart meter. Although NB Power placed orders for the meters well in advance of the deployment date, Itron, the meter vendor, has not met their delivery dates due to the material shortages. Based on the current forecast of meter shipments, mass deployment is now anticipated to begin in the spring of 2023 and continue for a 24 month period.

NB Power posts regular updates on the AMI project on our website at https://www.nbpower.com/en/about-us/regulatory/advanced-metering-infrastructure.

Transmission Line Life Extension Program ($23.0 million)

The objective of this program is to reduce the risks and probabilities associated with transmission line failures. NB Power maintains 243 transmission lines, many which are aging and need significant investment to ensure continued safe and reliable operation.

PLNGS Major Outage & Inspection 2024 Outage ($21.5 million)

PLNGS will conduct a planned outage starting in April 2024 and the 2023/24 spend is related to pre-outage work. This outage includes addressing equipment deficiencies, conducting preventive maintenance, implementing modifications, and conducting inspections, which contribute to ongoing reliability of the Station.

PLNGS Major Outage & Inspection 2023 Outage ($20.1 million)

PLNGS will conduct a planned outage in April 2023. This outage allows for inspections and maintenance to be conducted on critical equipment such as class III electrical maintenance and testing, installation of primary heat transport pump motor, and overhaul of the moderator pump which contribute to ongoing reliability of the Station.

Please refer to Appendix Q i. Point Lepreau Nuclear Generating Station Outage 2023 for more information.

Belledune Generating Station Major Outage & Inspection ($10.6 million)

The outage in 2023/24 will perform maintenance on the LP turbine and associated equipment and systems; including the balance of plant equipment requiring routine maintenance as well as complete the replacement of previously identified damaged secondary air heater baskets.

Eel River Synchronous Condenser Unit 1 ($10.8 million)

All three synchronous condensers at Eel River HVDC Station (SC1, SC2 & SC3) will require major rebuilds to replace their stator windings in the near future. These are original and have been in service since 1972. Upgrades to the hydrogen delivery system for each synchronous condenser will also be implemented, as well as new bearing oil seals, slip rings, and brush holder.

Coleson Cove Generating Station Unit 2 Major Outage & Inspection ($9.6 million)

The outage is a periodic inspection of the boiler and auxiliary equipment. Included in this outage is a major inspection and overhaul of the generator and low-pressure turbine. Other required maintenance will be performed to ensure the station remains fit for service.

Mactaquac Civil Infrastructure Refurbishment ($5.4 million)

Following the condition assessment that was completed as part of the planning for the Mactaquac Life Achievement Project ("MLAP"), there has been work identified that needs to be completed prior to the start of the MLAP execution. The major parts of this work are concrete repairs and items that are required to operate the plant safely and reliably until MLAP. The current planned scope for 2023/24 includes repairs to fishway piers #6 & #7, replacement of DamSmart software, intake transmission tower base repairs, west end pier crack repair, and reliability upgrades to cranes.

Advanced Distribution Management System ($5.1 million)

An Advanced Distribution Management System ("ADMS") is a foundational component of a modern electrical grid and essential to the future of NB Power. NB Power requires an ADMS to provide Distribution System Operations visibility and control needed to meet growing customer expectations and to manage the increasing complexity of a modern distribution system, which will enable the adoption of more renewable energy and an increase in volume and complexity of information.

## 5.3 ASSETS AND CAPITAL EXPENDITURES[1]

NB Power is an asset intensive organization with a Net Book Value of assets of $4.6 billion at March 31, 2022. Investment in new and existing infrastructure is required to ensure the on-going reliability of the system, to meet customer demands and remain current with growing electricity requirements.

Please refer to Table 5.3.1 for a breakdown of gross and net book values of NB Power assets for the 2023/24 test year compared to the 2022/23 budget. The variance is also provided below. Please note that each grouping provided includes all asset categories within the grouping.

[1] This section addresses Minimum Filing Requirements 87,88, and 89.

**Table 5.3.1**

**NB Power Corporation**
**Gross Value and Net Value of Assets**
Fiscal Years Ending March 31
(in millions $)

| | Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | **Generation** | | | | | | | | | | | |
| (2) | Gross Value | $ 5,243.8 | $ 5,029.4 | $ 5,008.1 | $ 4,685.6 | $ 4,818.1 | $ 4,579.9 | $ 4,658.7 | $ 235.7 | $ 21.3 | $ (132.5) | $ (78.9) |
| (3) | Depreciation | (2,286.7) | (2,026.4) | (1,983.8) | (1,774.9) | (1,840.0) | (1,495.7) | (1,720.6) | $ (302.9) | $ (260.3) | $ 65.1 | $ 224.8 |
| (4) | Net Book Value | $ 2,957.2 | $ 3,003.0 | $ 3,024.3 | $ 2,910.6 | $ 2,978.0 | $ 3,084.1 | $ 2,938.2 | $ (67.2) | $ (21.3) | $ (67.4) | $ 146.0 |
| (5) | **Transmission** | | | | | | | | | | | |
| (6) | Gross Value | $ 1,030.2 | $ 975.7 | $ 946.3 | $ 930.1 | $ 908.0 | $ 843.1 | $ 862.6 | $ 83.8 | $ 29.3 | $ 22.0 | $ (19.5) |
| (7) | Depreciation | (205.2) | (177.1) | (148.8) | (150.0) | (138.2) | (96.6) | (128.2) | $ (56.3) | $ (28.2) | $ (11.8) | $ 31.7 |
| (8) | Net Book Value | $ 825.0 | $ 798.6 | $ 797.5 | $ 780.1 | $ 769.8 | $ 746.5 | $ 734.4 | $ 27.5 | $ 1.1 | $ 10.3 | $ 12.1 |
| (9) | **Distribution** | | | | | | | | | | | |
| (10) | Gross Value | $ 1,813.1 | $ 1,718.4 | $ 1,736.1 | $ 1,624.4 | $ 1,674.1 | $ 1,523.9 | $ 1,596.4 | $ 77.0 | $ (17.7) | $ (49.7) | $ (72.5) |
| (11) | Depreciation | (786.1) | (744.6) | (729.1) | (695.4) | (696.1) | (640.0) | (679.4) | $ (57.0) | $ (15.4) | $ 0.7 | $ 39.5 |
| (12) | Net Book Value | $ 1,027.0 | $ 973.9 | $ 1,007.0 | $ 929.0 | $ 978.0 | $ 884.0 | $ 917.0 | $ 20.0 | $ (33.1) | $ (49.0) | $ (33.0) |
| (13) | **Other System Assets** | | | | | | | | | | | |
| (14) | Gross Value | $ 51.5 | $ 44.4 | $ 48.3 | $ 36.5 | $ 44.1 | $ 37.5 | $ 47.5 | $ 3.2 | $ (3.9) | $ (7.6) | $ (9.9) |
| (15) | Depreciation | (15.3) | (12.5) | (12.8) | (11.5) | (12.0) | (10.8) | (12.6) | $ (2.5) | $ 0.3 | $ 0.5 | $ 1.8 |
| (16) | Net Book Value | $ 36.3 | $ 31.9 | $ 35.5 | $ 25.0 | $ 32.1 | $ 26.7 | $ 34.8 | $ 0.8 | $ (3.6) | $ (7.1) | $ (8.2) |
| (17) | **Total Property, Plant & Equipment** | | | | | | | | | | | |
| (18) | Gross Value | $ 8,138.6 | $ 7,767.9 | $ 7,738.9 | $ 7,276.5 | $ 7,444.3 | $ 6,984.4 | $ 7,165.3 | $ 399.8 | $ 29.1 | $ (167.7) | $ (180.9) |
| (19) | Net Book Value | $ 4,845.4 | $ 4,807.4 | $ 4,864.3 | $ 4,644.7 | $ 4,758.0 | $ 4,741.3 | $ 4,624.4 | $ (18.9) | $ (56.9) | $ (113.2) | $ 116.9 |
| (20) | **Intangible Assets** | | | | | | | | | | | |
| (21) | Net Book Value | $ 52.8 | $ 56.3 | $ 45.3 | $ 59.3 | $ 35.6 | $ 55.9 | $ 44.4 | $ 7.5 | $ 11.0 | $ 23.7 | $ 11.5 |

Note to reader: Financial tables reflect differences due to rounding.

**VARIANCE 1 (Table 5.3.1)** [2]

**Generation - Gross value increased by $235.7 million (line 2, column 8) for 2023/24B compared to 2022/23B**. The primary driver of the increase in gross property, plant and equipment is the capital expenditures planned for 2023/24 of $211.0 million, mainly related to major outages and inspections at PLNGS, Coleson Cove and Belledune, along with other investments necessary to ensure asset reliability, safety and regulatory compliance. In addition, there are expenditures planned relative to the Mactaquac Life Achievement Project. Refer to Section 5.1 for a listing and description of capital projects greater than $5.0 million in 2023/24. In addition to capital spending changes there is an opening balance variance of $21.3 million.

**Generation - Net book value decreased by $67.2 million (line 4, column 8) for 2023/24B compared to 2022/23B.** This decrease is due to depreciation expense of $261.3 million and a net opening balance variance of $21.3 million, partially offset by planned capital expenditures of $211.0 million.

**Transmission - Gross value increased by $83.8 million (line 6, column 8) for 2023/24B compared to 2022/23B**. The primary driver of the increase in gross property, plant and equipment is capital expenditures planned for 2023/24 of $58.0 million, mainly related to transmission line life extensions and rebuilds, along with other infrastructure investments necessary to ensure reliability standards continue to be met. Refer to Section 5.1 for a listing and description of capital projects greater than $5.0 million in 2023/24. In addition to capital spending changes there is an opening balance variance of $29.3 million.

**Transmission - Net book value increased by $27.5 million (line 8, column 8) for 2023/24B compared to 2022/23B.** This increase is primarily due to planned capital expenditures of $58.0 million partially offset by depreciation expense of $28.1 million.

[2] Please refer to Attachment 1 (Variance Analysis 2), Attachment 2 (Variance Analysis 3) and Attachment 3 (Variance Analysis 4) for additional explanations of variances.

**Distribution - Gross value increased by $77.0 million (line 10, column 8) for 2023/24B compared to 2022/23B**. The primary driver of the increase in gross property, plant and equipment is capital expenditures planned for 2023/24 of $118.0 million, primarily driven by plans to modernize the power grid through investments in Advanced Metering Infrastructure (AMI) of $31.7 million.  Along with this major capital investment, there are regular planned expenditures of $86.3 million to ensure assets continue to operate safely and reliably.  Refer to Section 5.1 for a listing and description of capital projects greater than $5 million in 2023/24.  Partially offsetting the planned capital spending is an opening balance variance of $17.7 million and retirement of $22.2 million related to meter assets as a result of the AMI project noted above.

**Distribution - Net book value increased by $20.0 million (line 12, column 8) for 2023/24B compared to 2022/23B.** This increase is mainly due to planned capital expenditures of $118.0 million partially offset by depreciation expense of $54.6 million and a net opening balance variance of $33.1 million.

**Other Systems (Corporate Services) - Gross value of other systems increased by $3.2 million (line 14, column 8) for 2023/24B compared to 2022/23B**. The primary driver of the increase in gross property, plant and equipment within other systems is capital expenditures planned for 2023/24 of $6.6 million.

**Other Systems (Corporate Services) - Net book value increased by $0.8 million (line 16, column 8) for 2023/24B compared to 2022/23B**. This increase is due to planned capital expenditures of $6.6 million partially offset by depreciation expense of $3.4 million.

**Intangibles - Net book value increased by $7.5 million (line 21, column 8) for 2023/24B compared to 2022/23B**.  This increase is mainly due to capital expenditures of $5.1 million and a net opening balance variance of $11.0 million, partially offset by depreciation expense of $10.6 million.

# 6.0 CHANGE IN DEBT[1]

Table 6.0.1 below provides a breakdown of historical net debt and the amounts forecasted and budgeted for fiscal 2022/23 and 2023/24, respectively. The table shows net debt is forecasted to increase by $100 million (Table 6.01, line 7, column 2) in the 2022/23 fiscal year, compared to a budgeted increase of $32.9 million (Table 6.01, line 7, column 3). The larger than planned increase in debt in the 2022/23 forecast compared to budget is primarily due to higher capital spending resulting from the Point Lepreau extended maintenance outage, higher fuel and purchased power costs and higher financing costs.

Net debt is forecasted to increase in 2023/24 by $39.6 million (Table 6.01, line 7, column 1), assuming an 8.9 per cent rate increase is implemented. The increase is driven by planned capital expenditures, which are forecasted to exceed operating cash flow.

[1] This section addresses Minimum Filing Requirements 97, 98 and 99.

**Table 6.0.1**
**Change in Net Debt**
($ millions)

| Component | (1) 2023/24B | (2) 2022/23E | (3) 2022/23B | (4) 2021/22A | (5) 2021/22B | (6) 2020/21A | (7) 2020/21R | (8) Variance 1 (1)-(3) | (9) Variance 2 (2)-(3) | (10) Variance 3 (4)-(5) | (11) Variance 4 (6)-(7) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) Long-Term Debt | $ 4,902.8 | $ 4,800.3 | $ 4,608.4 | $ 4,631.0 | $ 4,641.5 | $ 4,733.8 | $ 4,711.0 | $ 294.4 | $ 191.9 | (10.4) | $ 22.8 |
| (2) Short-Term Debt | 672.4 | 747.0 | 846.7 | 859.3 | 596.0 | 607.7 | 656.2 | (174.3) | (99.7) | 263.3 | (48.5) |
| (3) Total Debt | 5,575.2 | 5,547.3 | 5,455.1 | 5,490.3 | 5,237.5 | 5,341.5 | 5,367.1 | 120.1 | 92.2 | 252.8 | (25.6) |
| *Less:* | | | | | | | | | | | |
| (4) Cash | (1.7) | (36.4) | (1.0) | (52.1) | (1.0) | (2.7) | (1.0) | (0.7) | (35.4) | (51.1) | (1.7) |
| (5) Sinking Funds | (496.1) | (473.1) | (483.4) | (500.4) | (434.9) | (409.8) | (480.7) | (12.7) | $ 10.3 | (65.5) | $ 70.9 |
| (6) Net Debt | $ 5,077.4 | $ 5,037.8 | $ 4,970.7 | $ 4,937.8 | $ 4,801.6 | $ 4,929.1 | $ 4,885.4 | $ 106.7 | $ 67.1 | $ 136.2 | $ 43.7 |
| | (1)-(2) | (2)-(4) | (3)-(4) | (4)-(6) | (5)-(6) | | | | | | |
| (7) Annual Change in Net Debt | $ 39.6 | $ 100.0 | $ 32.9 | $ 8.7 | $ (127.5) | | | | | | |
| (8) MWh Delivered (in thousands) | 19,202 | 20,912 | 17,379 | 20,897 | 16,546 | | | | | | |
| (9) Change in Net Debt / MWh | $ 2.06 | $ 4.78 | $ 1.89 | $ 0.42 | $ (7.70) | | | | | | |

Note to reader: Financial tables reflect differences due to rounding

Table 6.0.2 below provides a continuity schedule of net debt since it peaked in 2012/13. Net debt at the end of 2023/24 is forecasted to be $15 million higher (Table 6.0.2, line 8, column 12) than the peak of $5,062 million in fiscal 2012/13 (Table 6.0.2, line 6, column 1).

**Table 6.0.2**
**Continuity Schedule of Change in Total Net Debt**
($ millions)

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Actuals | | | | | | | | | | Forecast | Budget |
| **Fiscal Years Ending March 31** | **2012/13** [1] | **2013/14** | **2014/15** | **2015/16** | **2016/17** | **2017/18** | **2018/19** | **2019/20** | **2020/21** | **2021/22** | **2022/23E** | **2023/24B** |
| (1) Short-Term Debt | $ 687 | $ 858 | $ 784 | $ 855 | $ 977 | $ 871 | $ 897 | $ 691 | $ 608 | $ 859 | $ 747 | $ 672 |
| (2) Long-Term Debt | 4,752 | 4,567 | 4,605 | 4,524 | 4,427 | 4,406 | 4,609 | 4,825 | 4,734 | 4,631 | 4,800 | 4,903 |
| (3) Total Debt | 5,439 | 5,425 | 5,389 | 5,379 | 5,404 | 5,277 | 5,506 | 5,516 | 5,342 | 5,490 | 5,547 | 5,575 |
| *Less:* | | | | | | | | | | | | |
| (4) Cash | (1) | (3) | (3) | (2) | (1) | (6) | (4) | (3) | (3) | (52) | (36) | (2) |
| (5) Sinking Funds | (376) | (404) | (471) | (464) | (503) | (505) | (562) | (593) | (410) | (500) | (473) | (496) |
| (6) Net Debt | $ 5,062 | $ 5,018 | $ 4,915 | $ 4,913 | $ 4,900 | $ 4,766 | $ 4,940 | $ 4,920 | $ 4,929 | $ 4,938 | $ 5,038 | $ 5,077 |
| (7) Annual Change in Net Debt | | (44) | (103) | (2) | (13) | (134) | 174 | (20) | 9 | 9 | 100 | 40 |
| (8) Cumulative Change in Net Debt | | (44) | (147) | (149) | (162) | (296) | (122) | (142) | (133) | (124) | (24) | 15 |

Note to reader: Financial tables reflect differences due to rounding

[1] *Amounts reflect the combined balances that existed with the New Brunswick System Operator*

In recent years, NB Power's debt has been increasing primarily due to lower than expected operating cash flows resulting from circumstances such as an outage extension and unplanned outages at PLNGS that, combined with significantly higher fuel and purchased power prices, resulted in higher fuel and purchased power costs; a delayed rate increase in 2020/21; and a legislated zero per cent change in rates in 2021/22. Higher capital expenditures have further limited the funds available to reduce debt.

The proposed 8.9 per cent rate increase for 2023/24 is not sufficient to reduce debt in-year, but it will better enable NB Power to service its debt obligations, fund capital expenditures, offset inherent variability in earnings, and continue to progress towards achieving a minimum equity target of 20 per cent in future years. In the absence of the proposed rate increase, net debt would be increasing by more than the $39.6 million increase budgeted in fiscal 2023/24.

# 7.0 FINANCIAL AND ACCOUNTING POLICIES UPDATES[1]

NB Power reports financial statements under International Financial Reporting Standards ("IFRS"). The significant accounting policies used in preparing the financial statements are disclosed in the notes to the financial statements.

**Future changes to accounting policies**

New IFRS standards to be implemented are summarized in the following table and further described below.

| Standard | Effective Date | Year end |
|---|---|---|
| IAS 37 Provisions, Contingent Liabilities and Contingent Assets | April 1, 2023 | March 31, 2024 |
| IAS 1 Presentation of Financial Statements | April 1, 2023 | March 31, 2024 |
| IAS 1 Presentation of Financial Statements and IFRS Practice Statement 2 | April 1, 2023 | March 31, 2024 |
| IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors | April 1, 2023 | March 31, 2024 |

The International Accounting Standards Board ("IASB") issued amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets. The amendments relate to the costs that should be included as the cost of fulfilling a contract when assessing whether a contract is onerous. The amendments clarify that the cost of fulfilling the contract comprises all costs that relate directly to the contract. Such costs include both the incremental costs of fulfilling that contract and an allocation of other costs that relate directly to fulfilling contracts. The amendments apply to contracts existing at the date when the amendments come into effect.

[1] This section addresses Minimum Filing Requirements 23 and 100.

The IASB issued amendments to IAS 1 Presentation of Financial Statements. The amendments relate to the classification of liabilities as current or non-current. Specifically, the amendments clarify one of the criteria for classifying a liability as non-current is the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period.

The IASB issued further amendments to IAS 1 Presentation of Financial Statements and IFRS Practice Statement 2. The amendments help companies provide useful accounting policy disclosures. The key amendments include requiring companies to disclose their material accounting policies rather than their significant accounting policies; clarifying that accounting policies related to immaterial transactions, other event or conditions are themselves immaterial and as such need not be disclosed; and clarifying that not all accounting policies that relate to material transactions, other events or conditions are themselves material to a company's financial statements.

The IASB also issued amendments to IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors. The amendments introduce a new definition for accounting estimates, clarifying that they are monetary amounts in the financial statements that are subject to measurement uncertainty. The amendments also clarify the relationship between accounting policies and accounting estimates by specifying that a company develops an accounting estimate to achieve the objective set out by an accounting policy.

NB Power does not expect these amendments to have a material impact on the financial statements.

Please refer to Appendix C 2021/22 New Brunswick Power Audited Consolidated Financial Statements note 2d, New standards and interpretations not yet adopted for additional information on the standards not yet adopted.

Please refer to Appendix C 2021/22 New Brunswick Power Audited Consolidated Financial Statements note 3, Significant Accounting Policies, for NB Power's IFRS accounting policies.

# 8.0 FINANCIAL RISK MANAGEMENT POLICY UPDATES[1]

**Changes to Policies**

NB Power's Board of Directors reviewed the Corporation's and New Brunswick Energy Marketing Corporation's ("NB Energy Marketing" or "NBEMC") financial risk management policies in November 2020 and November 2021 and approved changes to the following policies:

- F-1: Financial Risk Management Framework Policy (November 2021)
- F-3: Commodity Price & Foreign Exchange/Interest Rate Risk Policy (November 2020)
- NBEMC-1: Financial Risk Management Framework Policy (November 2021)
- NBEMC-3: Commodity Price & Foreign Exchange Risk Policy (November 2020)

Minor wording changes were made to the policies such as changing Chairman to Chair and switching from the masculine form to the feminine form in the French language versions when referencing the President and CEO.

A summary of the approved changes made to the policies is as follows:

<u>Financial Risk Management Framework Policy (F-1)</u>
A minor wording change was made to reflect the Audit and Finance Committee name change.
<u>Financial Risk Management Framework Policy (NBEMC-1)</u>
A minor change was made to reflect the addition of new policy NBEMC-6 to the list of financial risk management policies that regulate the financial risk management program.

<u>Commodity Price & Foreign Exchange / Interest Rate Risk Policy (F-3)</u>

[1] This section addresses Minimum Filing Requirement 101.

A wording change was made to broaden the description of specified markets for heavy fuel oil price risk mitigation to “all oil markets with exposure”. This change was made due to a change in the pricing indexes being used in the fuel supply agreement.

Commodity Price & Foreign Exchange Risk Policy (NBEMC-3)

A wording change was made to broaden the description of specified markets for heavy fuel oil price risk mitigation to “all oil markets with exposure”. This change was made due to a change in the pricing indexes being used in the fuel supply agreement.

In addition to the changes described above, the Board of Directors also approved the following new policy:

- NBEMC-6: Renewable Energy Certificate Policy (November 2021)

The new policy for NB Energy Marketing outlines requirements for managing price risk associated with the purchase and sale of renewable energy certificates. This policy is required because of the increased volume of renewable energy certificates transactions and a need to formalize the operational guidelines that were being followed by NB Energy Marketing staff.

The financial risk management policies can be found in Appendix R. i. NB Power Financial Risk Management Policy changes ENGLISH and Appendix S. i. NB Energy Marketing Financial Risk Management Policy changes.

**Approved Exceptions**

There is one exception to report that is impacting the test year. The exception was formally approved by the NB Power Board of Directors in accordance with the requirements of the financial risk management policies of NB Power and NB Energy Marketing. The exception is as follows:

1. Natural Gas Hedging – in February 2016, the NB Power Board of Directors approved an exception to the Commodity Price & Foreign Exchange / Interest Rate Risk Policy of NB

Power to discontinue the completion of natural gas hedges until further certainty and clarity on the future index price risk could be obtained. As the exposure could not have been reasonably determined at the time, the exception was approved so as not to continue to put contracts on that may not effectively mitigate the actual market price exposure.

Following the purchase of Bayside Generating Station in March 2019, NB Power secured a long-term supply of natural gas from western Canada. Since the index price risk is known, NB Power resumed hedging natural gas for the Station. Forward prices for the index were low so NB Power executed a hedging strategy that locked in fuel prices for a five-year period from November 2021 to October 2026. This extended hedging period is permitted under NB Energy Marketing's Commodity Price & Foreign Exchange Risk Policy (NBEMC-03).

NB Power recently determined there is a high degree of certainty of the counterparty's source of natural gas for a natural gas PPA during the winter months and has resumed hedging natural gas for that period. The change was made after the 2023/24 budget was finalized so natural gas related to the natural gas PPA is unhedged in the test year.

**Internal Audit Results**

Deloitte concluded internal audits in August 2021 that assessed NB Power's and NB Energy Marketing's compliance to the financial risk management policies. The audits covered transactions completed during the period April 2019 to March 2021. The last compliance audit completed covered the period up to March 2019.

The overall audit results were positive with an overall audit opinion rating of effective with opportunity for improvement. The audits noted four medium priority observations and five low priority/value add observations. The four medium priority observations are summarized as follows:

Segregation of Duties

The audit noted that the foreign exchange trades are executed by the Treasury Department and the Treasury Department also records the trades into the accounting system without an independent review being completed. It was noted that this risk is partially mitigated due to the fact that two individuals must be present and sign off on foreign exchange trades.

Summary of Management Response – Management will implement a review of an independent party into the process for entering foreign exchange trades into SAP. Management will also implement a process whereby a check is completed by the Financial Risk Management group to compare the trades entered into SAP with the trades recorded in the financial risk management software.

Signed Trade Confirmations

The audit found a limited number of instances where trade confirmations were not signed by the Director of the middle office function.

Summary of Management Response – Management will ensure all trades are tracked, reviewed and signed by the Director of Treasury and Risk Management or a designate.

Sale of Capacity

The audit found that the middle office function was not performing risk management activities to ensure oversight of the sale of capacity.

Summary of Management Response – the Financial Risk Management group will begin tracking capacity sales.

Renewable Energy Certificate (REC) Reporting

The audit found that the middle office function was not performing risk management activities to ensure oversight of RECs.

Summary of Management Response – the Financial Risk Management group will begin tracking RECs. The Financial Risk Management group will include reporting of REC requirements and positions in monthly Financial Hedging Operating Committee and quarterly Financial Hedging Oversight Committee meetings.

The full audit reports can be found in Appendix T. NB Power Financial Risk Policy Review (prepared by Deloitte) and Appendix U. NB Energy Marketing Financial Risk Policy Review (prepared by Deloitte).

## 9.0 CLASS COST ALLOCATION[1]

NB Power utilizes an embedded Class Cost Allocation Study (CCAS) methodology which allocates the total cost of providing service among rate classes and compares allocated costs to the revenue generated by each customer class. The results are expressed as revenue-to-cost ratios (RCR) for each rate class and can be used as a basis for differential rate adjustments between customer classes to better align revenues with costs. Details of each of the schedules of the class cost allocation study methodology are presented in Appendix AI. 2023-24 CCAS Methodology Description.[2]

NB Power's current CCAS Methodology is in accordance with the Board's Order in Matter 271 – Review of NB Power's Class Cost Allocation Study Methodology, the Board's acceptance of NB Power's recommended CCAS model as part of Matter 458 – NB Power's 2020/21 General Rate Application, and changes proposed under Rate Design Matter 529. NB Power is not proposing any additional changes to the CCAS methodology in this application.

### 9.1 2023/24 CLASS COST ALLOCATION STUDY (CCAS)

The 2023/24 CCAS results are included in Table 9.1a below (see also Appendix BF. 2023-24 CCAS Model 8.9% Uniform Rate Increase (Model 3). These results take into account Board approved methodologies, Board directed changes, and CCAS data updates.

[1] This section addresses Minimum Filing Requirements 12 and 105.
[2] This Appendix addresses Minimum Filing Requirement 102.

**Table 9.1a - Proposed 2023/24 CCAS at Uniform 8.9 per cent Rate Increase**

| **Rate Class** | (1) **Fully Allocated Revenues** (in millions $) | (2) **Fully Allocated Cost of Service** (in millions $) | (3) **Revenue to Cost Ratios 2023/24 CCAS at Uniform 8.9% Rate Increase** |
|---|---|---|---|
| (1) Residential Class | 876.9 | 915.7 | 0.958 |
| (2) General Service I | 268.6 | 229.2 | 1.172 |
| (3) General Service II | 92.1 | 90.7 | 1.015 |
| (4) Small Industrial | 73.2 | 57.6 | 1.271 |
| (5) Large Industrial | 415.0 | 429.5 | 0.966 |
| (6) Wholesale | 127.9 | 131.1 | 0.976 |
| (7) Street Lights and Unmetered | 19.4 | 10.4 | 1.000* |
| **(8) Total/Overall** | **1,873.2** | **1,873.2** | **1.000** |

*After excess revenue reallocation

Table 9.1b below presents the results from the Board approved 2020/21 CCAS from Matter 458, with the Board-requested changes, and the proposed 2023/24 CCAS model at current rates (0% increase) and uniform 8.9 per cent rate increase.

**Table 9.1b - Board Approved 2020/21 CCAS, 2023/24 CCAS at Current Rates (0%), and 2023/24 CCAS at Uniform 8.9 per cent Rate Increase**

| Rate Class | (1) **Board Approved Revenue Requirement 2020/21 CCAS** | (2) **Proposed 2023/24 CCAS at 2022/23 Rates (0%)** | (3) **Proposed 2023/24 CCAS at Uniform 8.9% Rates** |
|---|---|---|---|
| (1) Residential Class | 0.952 | 0.964 | 0.958 |
| (2) General Service I | 1.215 | 1.165 | 1.172 |
| (3) General Service II | 1.082 | 1.024 | 1.015 |
| (4) Small Industrial | 1.086 | 1.261 | 1.271 |
| (5) Large Industrial | 0.962 | 0.958 | 0.966 |
| (6) Wholesale | 0.994 | 0.969 | 0.976 |
| (7) Street Lights and Unmetered | 1.000 | 1.000 | 1.000[4] |
| **(8) Total/Overall** | **1.000** | **1.000** | **1.000** |
| **Source** | **Appendix AG. CCAS - 2020-21 Decision Model (Model 1)** | **Appendix AH. 2023-24 CCAS Model at 2022-23 Rates (Model 2)** | **Appendix BF. 2023-24 CCAS Model 8.9% Uniform Rate Increase (Model 3)** |

The evidence includes the following CCAS Models for comparative purposes:

- Appendix AG. CCAS - 2020-21 Decision Model (Model 1)
- Appendix AH. 2023-24 CCAS Model at 2022-23 Rates (Model 2)[3]
- Appendix BF. 2023-24 CCAS Model 8.9% Uniform Rate Increase (Model 3)[4]

The Board Approved 2020/21 CCAS (Appendix AG. CCAS - 2020-21 Decision Model (Model 1)is based on the most recent CCAS model filed by NB Power (Matter 458, Exhibit NBP 1.83). The formatting and Revenue Requirement were updated after the decision of Matter 458, but the methodology was unchanged for this version of the CCAS model.

[3] This addresses Minimum Filing Requirement 102a.
[4] This addresses Minimum Filing Requirement 102b.

<u>Changes in the CCAS Model</u>

NB Power has filed proposed methodology changes to the CCAS as part of Matter 529 on Rate Design.  This methodology, and updated Load Research data, is implemented in CCAS Models 2 and 3 (Appendices AH. 2023-24 CCAS Model at 2022-23 Rates (Model 2) and BF. 2023-24 CCAS Model 8.9% Uniform Rate Increase (Model 3)) as filed.

The relevant impacts of the newly legislated Energy Efficiency and Demand Response Deferral Account ("Regulatory DSM Deferral Account") have been added to the CCAS model. The associated expenses are allocated to the rate classes on the basis of Energy Efficiency spending in the test year.  This allocation method selected by NB Power was previously recommended and continues to be supported by Elenchus, as presented in their CCAS study report on the issue (Matter 430 Exhibit NBP 1.77 – Appendix AR – New Brunswick Power Class Cost Allocation Study Update by Elenchus).

Energy efficiency cost allocation to the Wholesale rate class has been revised to include allocation of customer-related efficiency costs proportional to program participation rates. It was identified that utility tax was being allocated to water heaters in the CCAS model. Since there is no utility tax applied to water heaters, this was corrected and reallocated appropriately.

# 10.0 RATE DESIGN[1]

NB Power is proposing an 8.9 per cent uniform increase in its rates for in-province electricity sales. The 8.9 per cent increase in rates is to allow NB Power to cover its expected revenue requirement in the test year. NB Power is not proposing differential rate increases by customer class at this time. Differential rate increases would result in some customer classes receiving increases that are even higher than the 8.9 per cent rate increase, which is substantial relative to historical increases. Within the current economic climate of exceptionally high inflation, NB Power believes it would be inappropriate to place this additional burden on our customers at this time.

Section 10.2 addresses the topic of the Rate Design Model which has been used in the past to establish differential rate increases by customer class. Section 10.3 Proof of Revenue, provides a summary of the analysis that is contained in Appendix Z. 2023-24 Proof of Revenue 8.9% Uniform Rate Increase.

A complete copy of the Rate Schedules and Policies ("RSP") manual with proposed rates for sections N and O of the RSP is found in Appendix AC. i. NB Power Proposed Rates and Schedules.

NB Power is requesting approval of rental rates, fees, and charges associated with products and services found in sections N and O of NB Power's RSP Manual as follows:

- maintain the current rates for late payment charge, non-sufficient funds charge, and charges for the use of NB Power's eCharge Network as proposed in Matter 529 and as previously accepted by the Board.
- increase monthly rates for hot water heater rental service as detailed in Section 4.3.
- increase the Service Call Fee as detailed in Section 4.3.
- increase all other fees and rates by 8.9 per cent.

[1] This section addresses draft Minimum Filing Requirement 109.

In its Decision in Matter 430 – 2019/20 General Rate Application, the Board directed NB Power to apply a uniform increase for 2019/20 based on a combination of factors. All of those factors were addressed in NB Power's submission in Matter 458 – 2020/21 General Rate Application, other than the re-invigoration of the load research program. Subsequently, in paragraph 78 of its Decision in Matter 458 – 2020/21 General Rate Application, the Board concluded that:

> *"In the absence of any overriding reason, the Board will not entertain changes to the CCAS until such time that better load research is available for review and consideration."*

Further, in paragraph 80 of that Decision, the Board concluded that:

> *"In its filing, NB Power states that it has asked for a uniform rate increase, given the lack of confidence that the Board has expressed in the data that underlies the CCAS. In its view, there will be more timely and fitting opportunities to apply differential rate increases once the rate design matter is concluded."*

The improved load research data is now available and was used in the CCAS model (Appendix BF. 2023-24 CCAS Model 8.9% Uniform Rate Increase (Model 3)). Matter 357 NB Power Rate Design was concluded by the Board on October 4, 2020. The filing of evidence in the subsequent rate design matter was deferred by a year from June 2021 to June 2022. That filing by NB Power includes substantial evidence pertaining to load research and an updated Class Cost Allocation Study.

Deferring the use of differential rate increases will avoid subjecting customers to rate increases that are higher than the proposed increases which are already substantial relative to historic increases. Doing so will also allow time for a more effective consideration of differential rates in a future proceeding based on the evidence filed in Matter 529 and subject to consideration by the Board.

### 10.1 Load Research Data

NB Power has re-invigorated its load research program as directed by the Board in Matter 430. The re-invigoration was undertaken using foundational and important guidance as provided by DNV in a report that was filed in Matter 452 (Exhibit NBP 1.15 – Appendix E - Load Research Program Review (prepared by DNV GL Energy Insights)), and again in Matter 458 (Appendix AN - Load Research Program Review).

DNV has continued to provide load research advice and analysis to NB Power and is also providing load research software as a service. NB Power has also increased its internal load research capabilities. DNV's recent report on the status of NB Power's Load Research Program has been filed in Matter 529 (NBP01.23 – Appendix O – Load Research Reinvigoration Status Report).

NB Power has used its improved load research data from the re-invigorated program in its current Class Cost Allocation Study. The updated coincident and non-coincident peak values are found in Addendum II of the CCAS model (Appendix BF. 2023-24 CCAS Model 8.9% Uniform Rate Increase (Model 3)).

### 10.2 Rate Design Model[2]

The Rate Design Model is not included nor required for the 2023/24 GRA because NB Power is proposing a uniform increase in rates across all customer classes. Since all rate components have been applied to a uniform rate increase, the customer impact is the same for all customers no matter the customer load profile.[3]

### 10.3 Proof of Revenue[4]

The Proof of Revenue demonstrates that the proposed uniform increase in rates will recover the Revenue Requirement. The Proof of Revenue for 2023/24 is found in Appendix Z. 2023-

[2] This section addresses Minimum Filing Requirements 10, 11, 13, 104, and 106.
[3] This section addresses Minimum Filing Requirements 105 and 106.
[4] This section addresses Minimum Filing Requirements 104, 108

24 Proof of Revenue 8.9% Uniform Rate Increase and contains uniform rate increases for each rate class based on forecasted billing determinants (the revenue forecast based on a uniform rate increase of  8.9 per cent is included in Appendix AZ. Revenue Forecast Model). The Proof of Revenue reconciles with the total revenue requirement as presented in Table 3.0.1 of Section 3.0. The following table includes details from the Proof of Revenue workbook.

**Table 10.4**
**Revenue Projection For 2023-24**
(in millions $)

| | | (1) Annual Revenue Without Increase | (2) % Increase | (3) Annual Revenue After Increase | (4) Annual Increase |
|---|---|---|---|---|---|
| (1) | Residential | $ 737.5 | 8.9% | $ 803.0 | $ 65.5 |
| (2) | General Service I | $ 233.8 | 8.9% | $ 254.6 | $ 20.8 |
| (3) | General Service II | $ 77.1 | 8.9% | $ 83.9 | $ 6.9 |
| (4) | General Service Total | $ 310.9 | 8.9% | $ 338.5 | $ 27.6 |
| (5) | Small Industrial | $ 59.6 | 8.9% | $ 64.9 | $ 5.3 |
| (6) | Large Industrial | $ 282.5 | 8.9% | $ 307.8 | $ 25.3 |
| (7) | Wholesale | $ 108.7 | 8.9% | $ 118.3 | $ 9.7 |
| (8) | Street Lights | $ 23.2 | 8.9% | $ 25.2 | $ 2.1 |
| (9) | Unmetered | $ 4.8 | 8.9% | $ 5.2 | $ 0.4 |
| (10) | **Firm Energy Sales Sub-Total** | **$ 1,527.2** | **8.9%** | **$ 1,663.0** | **$ 135.8** |
| (11) | Interruptible/Surplus | $ 63.8 | | $ 63.8 | $ - |
| (12) | LIREPP Energy | $ 22.5 | | $ 22.5 | $ - |
| (13) | **Total In-Province Sales** | **$ 1,613.5** | | **$ 1,749.3** | **$ 135.8** |
| (14) | Out-of-Province Sales | $ 472.6 | | $ 472.6 | $ - |
| (15) | Rental Charges and Misc Fees | $ 31.6 | | $ 35.5 | $ 3.9 |
| (16) | Other | $ 56.9 | | $ 56.9 | $ - |
| (17) | **Subtotal** | **$ 2,174.5** | | **$ 2,314.3** | **$ 139.7** |
| (18) | Rate Rider Adjustment Factor | $ 7.9 | | $ 7.9 | $ - |
| (19) | **Total** | **$ 2,182.4** | | **$ 2,322.1** | **$ 139.7** |

Table values may reflect differences due to rounding

A "redline" version of the Rate Schedules and Policies ("RSP") manual with proposed rates in sections N and O of the RSP manual is found in Appendix AC. i. NB Power Proposed Rates and Schedules.[5]

[5] This section addresses Minimum Filing Requirement 108.