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Conservation Council *of* New Brunswick
Conseil de conservation *du* Nouveau-Brunswick

Submission to the Energy and Utilities Board: NB Power 2023/2024 General Rate Application, Matter 0541

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Summary

NB Power is seeking in its General Rate Application[1] an 8.9 percent rate increase for 2023/2024, a level significantly beyond expectations set in the 2019 Ten-Year Plan of 1.75 percent for this fiscal year. NB Power attributes 47 percent of the proposed rate increase to increased fuel and purchased power costs, which have increased between 58 percent and 158 percent over historical norms. The war in Ukraine and post-COVID inflation have indeed contributed to surging energy prices. The remaining portion of the increase, however, relates to in-province issues, including underperformance at Point Lepreau, operating and maintenance backlogs, and higher interest rates on debt, according to NB Power's rate application, and senior management statements made at the January 26, 2023 legislative Public Accounts Committee.

The Conservation Council of New Brunswick (CCNB) does not dispute that 2021/2022 was difficult and that 2023/2024 will present challenges. We argue in this submission, however, that despite global factors, the rate increase is excessive and that it is at least partly due to NB Power being:

1. Over reliant on fossil fuels and unreliable nuclear increasing its carbon liability.
2. Under investing in renewable energy and energy efficiency.

This submission provides evidence of missed opportunities relating to renewable energy investments, efficiency and electrification using energy modeling scenarios commissioned by Ecology Action Centre, in collaboration with the Conservation Council. The modeling shows that New Brunswick can renew its electricity system and manage rate pressures, but that investments must start now.

We also highlight the risks to New Brunswickers safety from an electricity system that is more polluting than it should be, and how higher rates put more households at risk of energy poverty.

Our recommendation is that before making its determination on the proposed 8.9 percent rate increase the EUB seek clarification on the:

[1] Available from the Energy and Utilities Board https://nbeub.ca/. Click on Matters and Hearings and enter 541 in the Matter field. Title: 2023-24 NB Power GRA Evidence (REVISED) (REPLACES NBP 01.03)

1. Details behind the planned increase in carbon tax liability for 2023/2024 with a break out of the contributing factors, including from the price itself, planned in-province fossil fuel use, and imports and exports.

2. Contribution to reduced overall and peak demand from an aggressive low-to-moderate income household retrofit strategy reaching more than 110,000 households over the next five years.

3. Non-nuclear and nuclear operations of Point Lepreau Generating Station based on actual experience, rather than NB Power capacity factor and outage projections. The analysis should be completed by external experts. The analysis should estimate future potential costs to maintain and operate the plant (e.g., capital, operating and maintenance, debt charges, wholesale electricity, fossil fuel costs, carbon tax), compared to alternatives supplying the same amount of electricity using in-province efficiency, renewable energy, storage and interties.

Finally, we suggest that the EUB strike a panel to investigate the operations of NB Power Energy Marketing Corporation to ensure we fully understand how participation in clean energy, renewable energy credit markets, and market trading generally, affect the dispatch of NB fossil fuel assets, greenhouse gas emissions, and rates, and the achievement of the renewable energy portfolio standard.

The next section provides contextual background to the Conservation Council's submission, followed by a section on Point Lepreau, Scenario Modeling, Recommendations, and Conclusion.

Background

This section provides context for the Conservation Council's submission to the Energy and Utilities Board in its consideration of Matter 0541, NB Power's 2023/2024 General Rate Application.

We believe our comments fall within the limited parameters set for this hearing by Sections 23(1) and 26(1) of the *Energy and Utilities Board Act* and Section 68 of the *Electricity Act*. The Conservation Council is guided for purposes of this submission by Section 68 (b, i, ii, iii) and (c) of the *Electricity Act*:

> (b) that all the Corporation's sources and facilities for the supply, transmission and distribution of electricity within the Province should be managed and operated in a manner that is consistent with **reliable, safe and economically sustainable service** and that will
>
> (i) result in the most efficient supply, transmission and distribution of electricity,

(ii) result in consumers in the Province having equitable access to a secure supply of electricity, and

(iii) result in the lowest cost of service to consumers in the Province, and

(c) that, consistent with the policy objectives set out in paragraphs (a) and (b) and to the extent practicable, rates charged by the Corporation for sales of electricity within the Province shall be maintained as low as possible and changes in rates shall be stable and predictable from year to year.

The Conservation Council is concerned that NB Power's General Rate Application demonstrates a failure to adequately consider what constitutes "safe" and that continued reliance on fossil fuels is out of step with its February 14, 2022 ministerial mandate letter directing NB Power to "work with the Province to reduce greenhouse gas emissions using least cost options."

Operating fossil-fuel powered generating stations releases greenhouse gases and emissions affecting air quality, both of which mean that electricity supply affects the safety of New Brunswickers through the direct health effects of air pollution, and the indirect effects of a changing and more extreme climate.

The fossil-dependent generating fleet also represents a significant carbon liability. A commitment to least cost should include avoiding dispatch decisions that increase carbon pricing payments. New Brunswick's proposed carbon pricing regime was approved by Environment and Climate Change Canada in November 2022. The new emissions intensity standards affecting NB Power, according to proposed amendments to the *Greenhouse Gas Reduction Act*, are shown in Figure 1.

t/CO_2-e/GWh	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Solid fuel	780	765	725	725	710	705	705	1
Liquid fuel	668	668	668	668	668	668	668	668
Gaseous fuel	395	395	395	390	370	370	370	240

Figure 1. Federally approved greenhouse gas intensity standards for NB Power.

Emissions intensity at NB Power fossil-fuel plants should decline for solid fuel from 811 $t/CO_2e/GWh$ (tonnes of carbon dioxide equivalent/billion-watt hours) in 2022 to 780 $t/CO_2e/GWh$ in 2023 and 765 $t/CO_2e/GWh$ in 2024. Liquid fuel intensity should be 668 $t/CO_2e/GWh$ in 2023 and 2024 from 795 $t/CO_2e/GWh$ in 2022. Gaseous fuels should emit 395 $t/CO_2e/GWh$ in 2023 and 2024 from 420 $t/CO_2e/GWh$ in 2022.

In its Interrogatories response to EUB staff questions[2], NB Power shows a budgeted carbon charge of $22.2-million in 2023/2024, a significant jump over the expected payment for 2022/2023 of $4.6-million, an increase of $17.6-million (p. 38, NBP 10.01, Figure 2). NB Power

[2] Available from the Energy and Utilities Board https://nbeub.ca/. Click on Matters and Hearings and enter 541 in the Matter field. Title: NBP 10.01

notes in the same document, in response to EUB staff questions on the implications of not meeting its renewable energy target, that the Crown corporation has conducted a sensitivity run in PROMOD to determine the cost of meeting the 40 percent Renewable Portfolio Standard (RPS). The cost of compliance was estimated to be $14.2 million.

We urge the EUB to further investigate the dynamics behind the expected jump in carbon price to determine the contributing factors. The federal carbon price schedule increases by $15/year to $65/tonne in 2023 and to $80/tonne in 2024. These incremental carbon price increases will continue to 2030 when the price will be $170/tonne. Without breaking out the factors influencing the carbon pricing liability for 2023/2024, we cannot determine what proportion of the cost is from the carbon price itself versus in-province dispatch, and imports or export sales decisions that affect greenhouse gas emissions, and exceed emissions intensity standards summarized in Figure 1. Figure 2 summarizes the historical and expected NB Power carbon pricing liability from 2019 to 2024 as reported to the EUB (NBP 10.01, p. 39).

Fiscal Year	Budgeted Carbon Surcharge ($000)	Actual Carbon Surcharge ($000)
2019/20	0	10,840
2020/21	3,026	9,910
2021/22	6,603	2,246
2022/23	4,587	N/A
2023/24	22,217	N/A

Figure 2. NB Power projected carbon pricing liability.

The Conservation Council's interpretation of the information NB Power has provided is that the cost of carbon is already higher than the cost of closing the 40 percent renewable energy portfolio standard gap for 2023/2024 (e.g., $14.7 million). According to NB Power's Revised General Rate Application, it is forecasting sourcing 35 per cent renewable energy for the 2023/2024 instead of the required 40 percent because the Kent Hills wind farm will be offline for part of the year, and increased costs from importing of renewable energy from out of province (p. 53).

The least-cost response today, and increasingly, is to avoid the carbon price as it rises year over year by $15/tonne to reach $170/tonne in 2030. As NB Power faces additional regulatory pressures from an impending federal clean electricity regulation, which will drive down fossil fuel use to near zero by 2035, the least cost for ratepayers is to increase the supply of renewable energy today. We develop this line of argument more fully in the next section (Scenario modeling).

Rate impact on energy affordability and energy poverty

NB Power's proposed 8.9 per cent rate increase for 2023/2024 constitutes a risk for low-to-moderate income households. Efficiency Nova Scotia's energy poverty tracking tool shows that for every one cent rate increase, the number of households experiencing energy poverty in that province increases two to three per cent. A household is considered to be in energy poverty if after-tax income energy expenditures (household and transportation) are double the national average of three percent (e.g., 6%).

According to the Canadian Urban Sustainability Practitioners (CUSP), an organization studying energy poverty, there are 114,790 households in New Brunswick meeting the six percent energy expenditure threshold. According to NB Power CEO, Lori Clark speaking on January 23, 2003 to the Public Accounts Committee, there are 40,000 households meeting the utility's Enhanced Energy Savings Program (EESP) threshold of earning $70,000 or less. There are currently 13,000 households on the wait list for this program. The target investment, given available funding, is 3,000 electric and 700 oil-heated homes per year. The average NB Power investment in these homes is $10,000. NB Power estimates that the rate increase proposed (e.g., 8.9 percent) 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. These potential savings suggest the need to significantly expand the programs reach to assist households that need it and to prevent growth in energy poverty.

At the current rate of home retrofits under the Enhanced Energy Savings Program, it will take about 10 years to reach all 40,000 eligible homes. Using the CUSP estimate, it will take 31 years to reach all households currently dealing with some level of energy poverty. Given NB Power plans rate increases each year in its 10-year plan and that this year's proposed rate increase is five times the projected rate increase of 1.75 percent for 2023/2024, it is legitimate to ask whether New Brunswick will ever eliminate energy poverty.

The question is worth asking despite the EUB previously ruling that social concerns are not ratepayer concerns leaving these important programs to be funded at the whim of federal and provincial governments. The Conservation Council, however, considers energy poverty a safety, equity (rural households are even more affected than urban households), and electricity system issue. Assuming the EUB does not agree energy poverty is a safety and equity issue within the meaning of the *Electricity Act*, another perspective is that targeting lower income households has system benefits in terms of reducing load, and peak demand given these households tend to be older and less energy efficient. These dynamics are worth exploring now or in future hearings given metrics suggesting up to 40 per cent of NB households face energy poverty, and that the residential sector is the biggest load on the system (p. 216, NBP 10.01). We urge the EUB to mandate NB Power to complete such a study and submit it as part of its rate hearing this year or for 2024/2025.

Energy Efficiency Regulation

To keep families financially whole, it is important to consider the value of energy efficiency in muting the effects of rate increases. The energy efficiency regulation requires an investment of 0.5 percent of retail sales for 2023/2024, rising to only 0.75 percent in 2029, a level well below our potential of at least 1.7 percent identified by Dunsky Energy Consulting in 2020. The report says almost $80-million annual investment could put NB on the path to achieving greater savings (Figure 3).

SPOTLIGHT - ANNUAL EFFICIENCY FORECASTS

ACHIEVABLE POTENTIAL – MID (2020-2034)

- Average Annual Efficiency Budget and Savings Potential

Energy	Avg Annual Savings	Avg Annual Budget	% of sales
Electric	227 GWh	76 M$	1.7%
Combustibles	280,499 GJ	16.5 M$	n/a
Natural Gas	*92,758 GJ*		*1.6%*
Oil	*112,694 GJ*		
Propane	*37,180 GJ*		
Biomass	*37,867 GJ*		

Figure 3. NB Power Potential Study: Stakeholder Presentation, January 8, 2020.

An aggressive energy efficiency strategy keeps household energy bills affordable. As we decarbonize and grow the electricity system there are legitimate concerns about the effect on rates from increased capital investment. The focus on keeping rates low, however, misses opportunities to keep household bills low even if electricity rates increase. There is a growing body of research showing that household energy costs can fall even as households use more electricity to power their lives, and as rates increase. Modeling by Enviroeconomics and Navius Research for the Ecology Action Centre and the Conservation Council shows aggressive electrification that reaches net zero by 2050, and a net zero grid by 2035, can generate household energy savings of five to six percent by 2035. The shift to electric vehicles plays a large role in cutting household energy costs, and represents a source of load growth and revenue for NB Power that is not yet reflected in NB Power's 10-year Plan, but should be more strongly reflected in the 2023 Integrated Resource Plan.

What do the people want?

While outside the purview of the EUB, the Conservation Council does want to include in this submission reference to polling we have conducted in late 2022 showing New Brunswick public opinion on sources of electricity. Wind, solar and energy efficiency are most preferred, while fossil fuel and biomass are least preferred.

Utilities need to make decisions over the next few years about how to supply electricity to customers. Please indicate how strongly you support or oppose the following electricity supply optionsin your community or region. You'll notice that there is a not sure option, but we encourage you to only use it if you really don't have an opinion. **Results October 2022: Strongly support, support, slightly support**

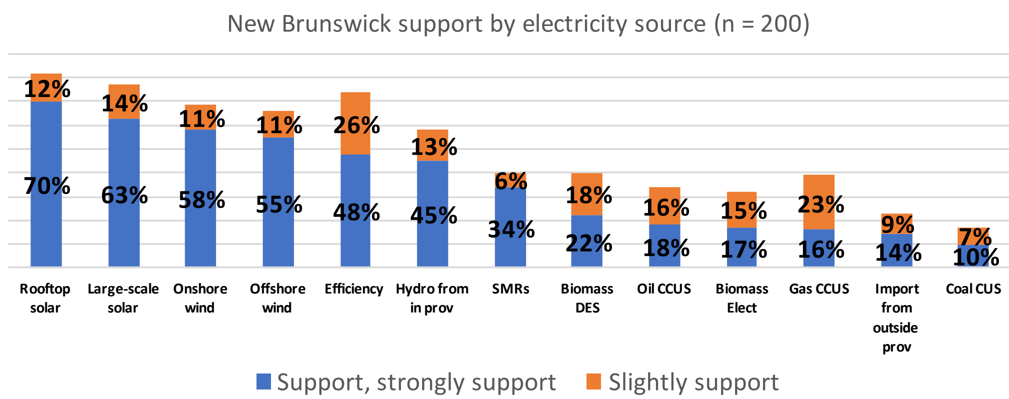

Figure 4. Public opinion polling: Energy source preferences.

Public preference for greener power, produced in New Brunswick by New Brunswickers is increasingly a least-cost strategy for NB Power relative to continued reliance on fossil fuels and exposure to unplanned nuclear power outages.

Point Lepreau

The Point Lepreau Nuclear Generating Station is a costly and unreliable source of electricity relative to NB Power's post-refurbishment expectations. The outcome of ongoing unplanned outages is that NB Power has higher capital costs than budgeted, is burning more dirty and expensive fossil fuels than it should, paying more carbon tax than it needs to, and buying high-priced power on the open market to meet winter peak demands. In other words, Point Lepreau is a factor in NB Power's application for an 8.9 per cent rate increase starting April 1, 2023.

It's time for the Energy Utilities Board to commission a panel on the future of Point Lepreau.

NB Power's General Rate Application reveals just how concerned the utility is about the state of the infrastructure critical to the safe operation of the Point Lepreau station. NB Power's rate application (p. 102) notes: "The current ageing 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."

The leak in the instrument line reported by NB Power on Dec. 15, 2022 is part of the station's 'Primary Heat Transport System.' In an appendix to the rate application (Appendix Q1)[3], the utility notes its plans for the "installation of a new Primary Heat Transport Pump Motor," (p. 6). The document goes on to say that "the primary purpose of the Primary Heat Transport System (PHT) is transporting heat from the fuel in the reactor core to the Steam Generators (boilers.) This is done in two separate loops using two very large pumps per loop.

The leak occurred after the rapid shutdown of the nuclear generation station due to the failure of a unit station transformer. The heat transport line moves heavy water that contains low to intermediate radioactive waste. The result was a radioactive leak in the containment building.

The revised Nov. 7, 2022 NB Power rate application shows there were 109 days of outages at Lepreau with capital costs exceeding $152-million (Table 5.2.1). The utility plans to spend more than $23-million by 2023-2024 on outages for Lepreau repairs.

The Energy and Utilities Board should independently assess the non-nuclear and nuclear operations of Point Lepreau Generating Station based on actual experience, rather than NB Power projections, and estimate future potential costs to maintain and operate the plant (e.g., capital, operating and maintenance, debt charges, wholesale electricity, fossil fuel costs, carbon tax). The investigation should assess the projected costs to operate the Point Lepreau Generating Station, compared to alternatives supplying the same amount of electricity using in-province renewable energy, storage, and energy efficiency.

The results of the EUB investigation should inform the development of the province's clean electricity strategy promised in its most recent climate action plan for 2022 to 2027 and due before 2025.

The next section summarizes modeling capable of setting New Brunswick on a course to low carbon liabilities, reduced rate pressures, and a net zero grid by 2035. The scenarios are part of a package of scenarios that if implemented require federal and provincial partnerships to fund electrification and phasing out fossil fuels from the electricity system.

Scenario modeling

The Ecology Action Centre, in collaboration with the Conservation Council, commissioned modeling by EnviroEconomics and Navius Research in 2022 to explore the implications of four net zero scenarios (reference case and three scenarios), and two additional scenarios exploring in-province renewables and storage. The technical note in this section of our EUB submission,

[3] Available at https://nbeub.ca/ at Hearings and Decisions tab. Enter 541 in the Matters # field, click on link to retrieve Appendix Q1.

describes these two new scenarios in detail and summarizes the original scenarios. For background detail on the energy models used, and the original scenarios, see the first report.

While not strictly falling within the mandate of the 2023/2024 NB Power rate hearing, the results of our modeling shine a light on the dangers of focusing only on near-term costs and rates without considering the longer-term implications of failing to invest in non-emitting renewable energy sources of electricity along with storage in our own province. The analysis shows that interties like the Atlantic Loop offer cost and pollution benefits, but that in-province supply is also competitive, and minimizes wealth transfer through imports. New Brunswick needs both in-province renewable energy supply and storage, as well as interties to enhance reliability and electricity trade.

We would note that the loss of 40 MW of expected wind power under the LORESS program due to missteps on the part of developers and NB Power reinforces the need for a more sophisticated approach to electricity planning as we move toward a net zero grid by 2035. The Conservation Council believes that these scenarios suggest the elements of an urgently needed provincial clean electricity strategy to guide EUB rulings.

Caveats

Ratepayers or Taxpayers

The modeling results in this technical note assume the cost of electrification is borne by ratepayers. A modeling exercise cannot determine the political arrangements needed to realize different energy futures. The Conservation Council believes federal and provincial partnership is needed to fund electricity system transition and reduce ratepayer effects due to rapid decarbonization capital investments, particularly in the early years (e.g., from now to 2030). We note, however, that over the period to 2050, the modeling results show that even with ratepayer funded investment, rate increases average 1%/year for the high renewable and storage scenarios.

Nuclear

We also note that scenario results relating to Point Lepreau show cost pressures to replace this power after 2040. This is not due to nuclear being cheaper than other options, but that the replacement requirement is large representing 50 percent of the system. Any change this large is going to be expensive. The question we need to answer is what is the least cost approach to replacing this load? The phase-out nuclear by 2040 scenario clearly shows replacements come from wind and hydro (p. 18). The results of the new scenarios featuring in-province renewables and storage are also our least-cost options in line with interties and hydro imports. The key to realizing our potential is to invest today.

Reference scenario

The high electrification net zero by 2050 reference case scenario described in the technical note reflects existing, planned, or modestly accelerated federal climate change regulations. Additional scenarios build on the reference case by adding interties, removing nuclear and/or adding renewable energy and storage. These additions offer insights into the potential effects of these marginal changes at a system level and suggest opportunities, risks and policy direction. Scenarios do not represent "truth" but rather are inputs into understanding system change. Policies modeled in the net zero electrification reference case include:

- A carbon price that emerges from a hard cap on emissions aligned with the 2030 target and net-zero by 2050 with tradeable allowances.
- Large industrial emitters under an output-based pricing system where the average cost of the carbon price is a fraction of the marginal carbon price.
- Emissions cap on electricity production from emitting sources starting in 2030.
- A net-zero building standard for new buildings after 2030.
- A regulatory ban on fossil heat sources in new buildings starting in 2025.
- A strengthened renewable fuel standard starting in 2025.
- ZEV mandates for new light-duty, medium-duty, and heavy-duty vehicles starting in 2030.
- A ban on process heat from fossil fuel in industry starting in 2030.
- Carbon Capture & Storage (CCS) mandated wherever possible starting in 2030.
- Renewable Natural Gas mandate starting in 2030.
- Methane regulations with a 50% reduction against 2010.

The reference case high-electrification scenario suggests an electricity system significantly larger than today rising from 3,130 MW to 5,385 MW, with one-quarter of capacity from wind and six percent capacity from solar. In-province renewable and storage scenarios suggest a lower growth trajectory of between 30 and 40 percent, with wind contributing 33 to 39 percent of capacity and solar about two percent of capacity. As noted in the first phase of this study, the phase out of Point Lepreau leads to significantly more wind and hydro via interties on the system (p. 18).

With this background in mind, we turn to the technical note developed by Dave Sawyer of EnviroEconomics and Noel Melton of Navius Research.

Technical note in net zero scenarios for New Brunswick

Analysis by Dave Sawyer (EnviroEconomics) and Noel Melton (Navius Research)

Introduction

Achieving net zero emissions by 2050 will require electricity system operators to make large bets on how they will meet growing demand while decarbonizing their electricity mix. Choices about the supply mix to meet future demand requires a sound analytical foundation to understand relative costs to meet growing demand. In this note we present selected results from five electricity supply scenarios for New Brunswick under a net zero final demand constraint.

Consistent with our previous study, end-use demand is set to align with a high electrification net zero by 2050 scenario. However, generation and capacity investments respond to marginal changes in demand associated with differing cost and technology assumptions in the scenarios.

Two versions of the Navius IESD model are used to assess the scenarios. The first version used in the original modelling allowed for new interties to be developed and due to computational limitations, storage options were not available. In the second iteration of the modeling, the model accommodates utility-scale storage while new significant interties under an Atlantic Loop are precluded.

All policies are compared against this high electrification net zero reference case across several indicators including total system cost, electricity price, net imports, changes in capacity and generation with renewables paired with storage, and greenhouse gas emissions.

Scenarios assessed

Five scenarios and a reference case are assessed.

The **reference case promotes high electrification and net zero by 2050**. Canada implements sufficient policy to achieve a 40-45% reduction in GHGs in 2030 and net zero by 2050. The modelled scenario achieves national emissions that are 42% below 2005 in 2030, while gross emissions in 2050 are 100 megatonnes (Mt), assuming these remnant net-zero emissions are reduced through carbon removal, inducing nature-based solutions and direct air capture. Point Lepreau is not retired in 2040 and operates throughout the entire simulation. Small modular reactors are not available in the simulations as a policy choice and because this technology is not yet a technology option to compete. All other technologies compete on levelized cost basis subject to policies and technology constraints in each scenario.

This reference case, and therefore all following scenarios, is compliant with the developing federal Clean Electricity Regulation.

The three Atlantic Loop scenarios from the original modeling include:

1. **Atlantic Loop scenario: Net zero + NB retires Lepreau in 2040.** As requested in the first set of analysis one scenario assesses the planned phase-out of the Point Lepreau Nuclear Generating Station by 2040. Small modular reactors are not available in the simulations as a policy choice and because this technology is not yet a technology option to compete, but all other generating technology competes on a cost basis. In all other scenarios, Point Lepreau continues to operate through 2050[4].

2. **Atlantic Loop scenario: Net zero + QC large hydro intertie.** A 1,000 MW line is built from Newfoundland and Labrador, wheeled through Quebec and entering New Brunswick. A 500-MW line is built for exchange between New Brunswick and Nova

[4] This allows a comparison with no nuclear option in phaseout scenario. CCNB plans additional modeling research in 2023 to more fully develop and analyse an efficiency, renewables/storage, interties and no nuclear scenario.

Scotia. Indicative costs include $1.6B in capital cost for transmission backbone upgrades between Nova Scotia and New Brunswick under a range of financing assumptions with delivered energy costs of $50 to $80 per MWh; any required transmission upgrades to the Quebec transmission system would either be incremental or would need to be included in the delivered energy cost.

3. **Atlantic Loop scenario: Net zero + Maritime Link 2 intertie.** A 250-MW line, or Maritime Line 2, is built between Newfoundland and Labrador and Nova Scotia. Indicative costs include $1B in capital cost for 250MW undersea transmission cable between Nova Scotia and Newfoundland and Labrador under a range of financing assumptions and a range of delivered energy costs of $50 to $80 per MWh.

Two new scenarios compare storage options and renewable generation costs. We examine the potential of storage, greater declining costs for renewables, and lack of intertie expansion to increase the adoption of wind and solar under two new scenarios. The updated analysis uses the region module of IESD, which does allow for storage. Specifically, this analysis considered the potential for utility-scale lithium-ion batteries based on optimistic assumptions from NREL as shown in Table 1.

4. **Utility-scale storage with current renewable costs (Storage + Current cost renewables).** Current cost renewables are paired with utility-scale storage. Innovations in renewable generation technology observed in today's marketplace become more widespread, and innovations that are nearly market-ready today come into the marketplace during the simulation. Table 2 provides the cost assumptions under the moderate scenario based on the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline report.

5. **Utility-scale storage with low renewable costs (Storage + Low-cost renewables)**. Low-cost renewables are paired with utility-scale storage. Innovations in renewable generation technology that are far from market-ready today are successful and become widespread in the marketplace. New technology architectures could look different from those observed today. Table 2 provides the cost assumptions under the advanced renewables scenario.

Table 1: Cost of lithium-ion batteries ($2021)

	2020	2030	2050
Storage CAPEX ($/kW)	316	146	66
Power CAPEX ($/kWh)	132	61	28

Source: National Renewable Energy Laboratory. 2020. *Cost Projections for Utility-Scale Battery Storage: 2020 Update.* https://www.nrel.gov/docs/fy20osti/75385.pdf

Note: Assumes a CAD-USD exchange rate of 1.3.

Table 2: Capital cost of solar and wind ($2021/kW)

	2020	2030	2050
Current costs scenario			
Solar	1,741	915	672
Wind	2,045	1,158	871
Low-costs scenario			
Solar	1,741	859	648
Wind	2,045	976	732

Source: National Renewable Energy Laboratory. 2022. *Annual Technology Baseline*. https://atb.nrel.gov/electricity/2022/technologies
Note: Assumes a CAD-USD exchange rate of 1.3. Current costs = moderate NREL scenario, low cost = NREL advanced scenario.

Insights

Total system cost

Annual system costs are summed, and a net present value is calculated for the scenarios between 2024 and 2050. We report on five groups of costs from the model:

- Capital expenditures or CapEx costs are calculated and analyzed using a capital recovery factor. New transmission costs under the Atlantic Loop scenarios are annualized using a capital recovery factor.

Operating costs include fuel costs, fixed operating costs, and variable operating costs.

- Export sales and import costs are both included.
- Carbon payments under various provincial and federal programs are calculated.

All costs are streamed out over the 26-years from 2024 to 2050 and discounted back to 2021 dollars using a rate of 3%.

Table **3** shows the percentage change in the net present value for the entire period relative to the reference case.

The scenario with the highest total cost is the retire nuclear in 2040 scenario.[5] The lowest total cost scenario is the large hydro scenario importing a large share of total consumption from Quebec. The addition of storage paired with renewable's shows a low total cost relative to all scenarios.

An upshot of storage, coupled with low-cost renewables, is a reduction in electricity system costs in most provinces in the Atlantic region. The greatest benefit is experienced in PEI, where electric batteries could reduce electricity costs by almost 17% in 2050 (from what they otherwise would have been). The benefit is largest in PEI due to the high share of generation

[5] As already noted, the cost implications relate to replacing 50% of load, rather than assumptions about the cost of nuclear.

from new renewables in that province. New Brunswick doesn't experience this magnitude of benefit because greater adoption of storage in other regions reduces demand for its electricity exports.

Regardless of the scenario, large capital expenditures are inevitable. This is particularly the case in the nuclear retirement scenario, where about 50% of total generation needs to be replaced when Point Lepreau is taken offline. The renewables with storage scenarios indicate that total system costs can be kept down with an approach that adds more renewables generation and storage starting as soon as possible.

Table 3: Total system costs (billion 2021)

Net Present Value @3%; 2024 to 2050

	CapEx	OpEx	Carbon	Exports	Imports	New Transmission	Total Cost
High electrification net zero case	$13,730	$5,369	$2,280	-$3,854	$4,609	$0	$20,904
Net zero + QC large hydro intertie	$12,289	$3,789	$995	-$6,107	$8,213	$1,119	$19,179
Net zero + Maritime Link 2 intertie	$11,854	$3,902	$1,020	-$4,082	$7,813	$231	$20,506
Net zero + NB retires Lepreau in 2040	$12,845	$3,563	$1,178	-$4,419	$9,557	$0	$22,724
Storage + Low-cost renewables	$13,857	$4,783	$1,586	-$3,724	$5,214	$0	$20,749
Storage + Current cost renewables	$13,849	$4,804	$1,721	-$4,244	$5,590	$0	$20,696

Note: Values shaded green are preferred. A three-colour stop light scheme where dark red is the highest value, yellow is the 50th percentile, and dark green is the lowest value

Electricity Price

The indicator is the wholesale price of electricity expressed as an index against the 2020 reference case. This indicator can be interpreted as a percentage increase in the electricity rate for households and businesses. Note that the modeling does not make any assumptions about the share of system costs that the federal government will contribute. Instead, the analysis assumes that the ratepayer will ultimately be responsible for all increases in system costs. To the extent the federal government subsidizes capital costs, the rate impacts identified below will be mitigated.

Both the Atlantic Loop intertie scenarios have similar costs to the storage plus renewable scenarios. In the shorter-term, with higher capital costs to deploy renewables, electricity prices would likely be higher under the with storage and renewables cases. Note the intertie scenarios have long construction lead times and costs are not experienced until at least 2030. The large hydro case with an intertie to Quebec has the lowest electricity prices followed by the two storage scenarios. Over the longer-term electricity prices are highest under the retiring nuclear scenario.

Table 4 provides an overview of the cumulative cost increases for each period by scenario. For example, 1.14 would indicate that between 2020 and 2025, the total rate increase would be 14%. Table 5 provides the annualized increase for each scenario.

Based on the analysis, the lowest system costs over the simulation time period is for the intertie scenario with large hydro from Newfoundland through Quebec followed closely by the two renewables plus storage scenarios.

Table 4: Increase in the price of electricity

(Net zero reference case 2020 = 1)

	2025	**2030**	**2035**	**2040**	**2045**	**2050**
Net zero + QC large hydro intertie	1.14	1.29	1.10	1.29	1.30	1.35
Net zero + Maritime Link 2 intertie	1.14	1.41	1.39	1.38	1.40	1.49
Net zero + NB retires Lepreau in 2040	1.14	1.33	1.33	1.90	1.87	1.95
Storage + Low-cost renewables	1.21	1.25	1.28	1.25	1.31	1.35
Storage + Current cost renewables	1.21	1.27	1.21	1.29	1.33	1.39

Note: Values shaded green are preferred. A three-colour stop light scheme where dark red is the highest value, yellow is the 50th percentile, and dark green is the lowest value

Table 5: Annual electricity rate change

	2021-25	2026-30	2031-35	2036-40	2041-45	2046-50	Average change 2020-50
Net zero + QC large hydro intertie	2.7%	2.4%	-3.0%	3.3%	0.1%	0.8%	**1.0%**
Net zero + Maritime Link 2 intertie	2.7%	4.4%	-0.3%	-0.2%	0.4%	1.2%	**1.3%**
Net zero + NB retires Lepreau in 2040	2.7%	3.1%	0.0%	7.4%	-0.3%	0.8%	**2.2%**
Storage + Low-cost renewables	3.9%	0.7%	0.4%	-0.5%	0.9%	0.6%	**1.0%**
Storage + Current cost renewables	3.8%	1.0%	-0.9%	1.2%	0.7%	0.9%	**1.1%**

Note: Values shaded green are preferred. A three-colour stop light scheme where dark red is the highest value, yellow is the 50th percentile, and dark green is the lowest value.

Net Imports

Wealth transfers to other jurisdictions. Each scenario is assessed based on the ratio of net imports over total domestic consumption. From the modeling, we subtract exports from imports to calculate net imports and then divide this by total consumption in five-year increments to 2050. The higher the ratio, the greater the wealth transfer from ratepayers in New Brunswick to system operators in other jurisdictions.

Table 6: Net imports over total consumption

	2020	2025	2030	2035	2040	2045	2050
Net zero + QC large hydro intertie	9%	23%	25%	28%	32%	29%	29%
Net zero + Maritime Link 2 intertie	9%	23%	25%	28%	30%	26%	26%
Net zero + NB retires Lepreau in 2040	9%	23%	26%	30%	36%	32%	29%
Storage + Low-cost renewables	10%	24%	23%	21%	21%	20%	19%
Storage + Current cost renewables	10%	24%	23%	23%	23%	21%	20%

Note: Values shaded green are preferred. A three-colour stop light scheme where dark red is the highest value, yellow is the 50th percentile, and dark green is the lowest value

Change in capacity and generation with storage

Storage costs are coming down allowing renewable generation to take off. Technologies to store electricity are therefore important for integrating higher levels of renewables into New Brunswick's electricity system.

The addition of storage paired with renewables results in a reduction in the generation capacity needed in any given period. Table 7 shows how the adoption of storage (combined with lower cost assumptions for solar and wind as described above) influences generation capacity relative to the no storage scenario.

Total electricity generation does not change up very much but with the addition of storage, natural gas generation falls off significantly while wind expands. The model indicates that when paired with storage, wind out competes solar paired with storage (Table 8).

A few observations from the analysis:

- Coal-fired power at Belledune is phased out prior to 2030 in all scenarios, dropping its share of total generation from ~50% in 2015 to zero by 2030.
- Biomass is not adopted on a cost-effective basis in any scenario.
- In the absence of electricity storage, thermal capacity grows to meet reserve requirements. This is true even under a scenario in which New Brunswick achieves net zero (in which case thermal plants are operated at very low-capacity factors, e.g., <5%). Electricity storage provides an opportunity to contribute to reserve margins and better utilize renewable resources.

Table 7: Change in generating capacity with storage (MW)

	2030	2035	2040	2045	2050
Oil/Diesel	-70	-70	-70	-70	-70
Natural Gas	-299	-431	-665	-893	-1,103
Cogeneration					
Nuclear			71	91	
Hydropower					
Wind	-62	-39	-87	-89	43
Solar			-35	-123	-229
Biomass					
Total	**-431**	**-540**	**-787**	**-1,084**	**-1,360**

Table 8: Change in electricity generation with storage (GWh)

	2030	2035	2040	2045	2050
Oil/Diesel	0	0	0	0	0
Natural Gas	-165	-365	-405	-476	-588
Cogeneration					
Nuclear					
Hydropower					
Wind	-83	293	529	886	1,371
Solar			-47	-206	-297
Biomass					
Total	**-248**	**-72**	**76**	**204**	**486**

Greenhouse gas emissions

All scenarios result in a significant decline in emissions from current levels.

Table 9: GHG emissions

(kilotonnes CO2e)

	2020	2030	2040	2050
Net zero + QC large hydro intertie	**~2,900**	**168**	**193**	**214**
Net zero + Maritime Link 2 intertie		**169**	**200**	**216**
Net zero + NB retires Lepreau in 2040		**168**	**259**	**273**
Storage + Low-cost renewables		**257**	**274**	**3**
Storage + Current cost renewables		**278**	**296**	**4**

Note: Values shaded green are preferred. A three-colour stop light scheme where dark red is the highest value, yellow is the 50th percentile, and dark green is the lowest value

Recommendations

The Conservation Council recommends that before the EUB makes its determination on the proposed 8.9 percent rate increase that clarification be sought on the:

1. Details behind the planned increase in carbon tax liability for 2023/2024 with a break out of the contributing factors, including from the price itself, planned in-province fossil fuel use, and imports and exports.

2. Contribution to reduced overall and peak demand from an aggressive low-to-moderate income household retrofit strategy reaching more than 110,000 households over the next five years.

3. Non-nuclear and nuclear operations of Point Lepreau Generating Station based on actual experience, rather than NB Power capacity factor and outage projections. The analysis should be completed by external experts. The analysis should estimate future potential costs to maintain and operate the plant (e.g., capital, operating and maintenance, debt charges, wholesale electricity, fossil fuel costs, carbon tax), compared to alternatives supplying the same amount of electricity using in-province efficiency, renewable energy, storage and interties.

Finally, we suggest that the EUB strike a panel to investigate the operations of NB Power Energy Marketing Corporation to investigate how participation in clean energy, renewable energy credit markets, and market trading generally, affect the dispatch of NB fossil fuel assets, greenhouse gas emissions, and rates, and the achievement of the renewable energy portfolio standard.

Conclusion

The Energy and Utilities Board rate hearing process is complex and overwhelming for New Brunswick non-profit groups. Our capacity to review thousands of pages of material and participate as intervenors is limited. The Conservation Council is aware that our contribution to the rate hearing through this submission colours outside the lines of the *Electricity Act* and the *Energy and Utilities Board Act*. Unfortunately, even with limited ability to participate, the EUB hearing process is almost the only opportunity to engage on electricity issues in New Brunswick.

The province rarely engages in effective public consultation. NB Power uses online surveys that are not rigorous in terms of question format and delivers data that is unlikely to be reliable as a foundation for decision-making.

The province requires open and transparent processes for developing a clean electricity strategy and to update its energy policy to guide the work of the EUB. The EUB rate hearing process would also benefit from more transparency, and less confidentiality. Intervenor funding, in addition to the work of the Public Intervenor, would also contribute to better outcomes for ratepayers, the environment, our health, and our ability to compete in a zero-emitting world.