BEFORE THE

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF EL-002-2025

RENEWABLE INTEGRATION AND

GRID SECURITY (RIGS) PROJECT

Direct Testimony
of
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on Behalf of
Public Intervener for the Energy Sector

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I. Background and experience

Q1. Please state your name, position, place of employment, and business address.

A1. My name is P. Jeffrey Palermo. I am employed as an Executive Consultant with PJP Consulting, a power system engineering consulting firm. My business address is 2405 NW 36 Street, Boca Raton, FL 33431.

Q2. What is your educational and professional background?

A2. I founded and have been employed by PJP Consulting since 2014. From 1979 to 2014, I worked for DNV GL, KEMA (DNV GL acquired KEMA in 2012) and CSA Energy Consultants (CSA merged with KEMA in 1998). From 1976 to 1979 I worked for the Jacksonville Electric Authority (JEA) in Florida.

Throughout my career, I have been responsible for developing transmission and generation expansion plans, conducting economic and financial evaluations, analyzing blackouts, performing pooling and coordination studies, evaluating inter-company contracts, reviewing and comparing national planning and pooling practices, and implementing the resulting plans. I have taught at the university level and managed consulting projects across most regions of the US and in more than 30 other countries.

I earned my Bachelor's Degree in Electrical Engineering from Northeastern University in 1975 and my Master's Degree in Electrical Engineering in 1977. I also earned a Master's Degree in Business Administration from the University of North Florida in 1978.

While at the JEA, I was responsible for bulk system planning, planning interconnections and transmission facilities, developing plans for jointly owned generating stations, and conducting coordination and pooling studies with the Florida Coordinating Group.

A member since 1976, I have participated in the planning and operating committees of CIGRE (Conférence Internationale des Grandes Réseaux Électriques) since 1985. CIGRE is a global nonprofit organization in the field of high-voltage electricity. Its activities include the technical and economic aspects of the electric grid, as well as environmental and regulatory factors. I was the US representative to Study Committee C1, System Development & Economics, and remain active. Study Committee C1 supports energy system planners, asset managers, and decision makers worldwide in anticipating and successfully managing the system changes brought about by the energy transition, it facilitates and promotes planning methods to share the latest practices, research, and recommendations. Through personal contacts established via CIGRE, I have stayed informed about developments worldwide. I serve as the US representative on power system development and economics.

I was part of the task force that developed the CIGRE Power System Reliability Analysis Guide. Recently, I served as the Convenor for a Working Group reviewing the Potential Roles of Energy Storage in Electric Power Systems. Before that, I was the Convenor of a Working Group examining the Future of Reliability in Light of New Developments in Customer Flexibility and Communication. Additionally, I am a Senior Member of the Institute of Electrical and Electronics Engineers (IEEE), where I have been involved in system planning and operation activities.

I have over 50 years of experience in the power system field, specializing in generation and transmission planning, reliability analyses, blackout investigations, and the effects of restructuring and markets. I have been responsible for both technical and economic analyses of generation and transmission plans across a wide range of market and non-market structures. Additionally, I have participated in various utility studies and analyses throughout all regions of the US and Canada.

Regarding system plans and planning criteria, I have advised utilities and stakeholders across the United States, Canada, Australia, Brazil, Chile, China, Costa Rica, the Dominican Republic, Ecuador, Egypt, Belgium, Cook Islands, Hong Kong, Iceland, Indonesia, Japan, Malaysia, Mexico, New Zealand, Niue, Peru, the Philippines, Russia, St. Kitts and Nevis, St. Croix, St. Thomas, Saipan, Samoa, Singapore, South Africa, Taiwan, Tonga, Tuvalu, Venezuela, and Vietnam on these topics. I evaluated electric system blackouts, starting with a 1976 blackout in

Jacksonville, Florida, and the several blackouts that occurred elsewhere in the state over the next two years. I also assessed blackouts in France, New York, California, Delaware, Idaho, Oregon, Pennsylvania, New Jersey, Ontario, Malaysia, and Australia.

In North America, I have advised and assisted utilities and other stakeholders across numerous states and provinces, including Alberta, British Columbia, Arizona, California, Colorado, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Maryland, Massachusetts, Michigan, Missouri, Montana, Nevada, New Brunswick, New Mexico, New England, North Carolina, New Jersey, New York, North Dakota, Ohio, Ontario, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Virginia, Washington, West Virginia, and Wisconsin, in developing and evaluating transmission plans. This work involved a broad range of system analyses using various steady-state and dynamic system analysis tools and techniques.

I have represented all sectors of the utility industry, ranging from regulatory agencies such as the Federal Energy Regulatory Commission and state commissions in Virginia, Iowa, and Arizona. My experience also includes large electric public and private utilities such as Dominion Virginia Power and Southern California Edison, as well as public utilities like Bonneville Power Administration. I have worked with cooperatives such as Seminole Electric Cooperative and North Carolina Electric Membership Cooperative, utility customers and suppliers such as US Steel and

TransCanada, wind developers, independent system operators like the Alberta Electric System Operator, transmission developers, and independent power producers. Additionally, I have represented various intervenor groups, including the Sierra Club, as well as many local stakeholder groups.

Q3. Have you been responsible for conducting and supervising powerflow and other similar power system studies?

A3. I have been conducting powerflow and related studies since 1976, when I joined the Planning Department of the Jacksonville Electric Authority in Florida. Over the decades, I have completed and overseen hundreds of powerflow studies for utilities both large and small.

I have also conducted numerous dynamic studies of system response to various transmission and generation contingencies. These studies covered various stability issues utilities might face, including voltage collapse analyses. Additionally, I have been responsible for various other transient event studies.

Finally, I have been responsible for numerous production-cost studies. Production-cost programs simulate the annual operation of a power system and are used to analyze how different generation and transmission plans and policies affect yearly fuel costs.

Q4. Have you appeared before the New Brunswick Energy and Utilities Board?

A4. Yes. In The Matter of EL-001-2025 NB Power's 2025 Large Transmission Capital Projects Application on behalf of the Public Intervener for the Energy Sector.

Q5. Have you testified in proceedings before other utility regulatory commissions?

A5. Yes. I have testified on various electric system-planning matters before the Federal Energy Regulatory Commission (FERC), the Arizona Corporation Commission, the Colorado Public Utilities Commission, the Virginia Corporation Commission, the Alberta Energy Utilities Board, the Alberta Utilities Commission, the Alberta Energy Board, the Iowa Utilities Board, the Australian Energy Market Operator, the Kansas Legislative Committee on Energy, the Michigan Public Service Commission, the Australian Reliability Panel, the Australian Energy Market Commission, the North Carolina Utilities Commission, and several arbitration panels.

I have also submitted written testimony to a Federal Bankruptcy Court, the Idaho Public Utilities Commission, the Public Utility Commission of Oregon, the New Zealand Electricity Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Massachusetts Energy Facility Siting Council, and the Missouri Public Service Commission.

Q6. What were you asked to do in connection with this case?

A6. The Public Intervener for the Energy Sector engaged me to review the technical filings in this matter.

Q7. What materials have you reviewed related to this case?

A7. I have reviewed the *Renewable Integration and Grid Security Project, Evidence,* dated 31 October 2025 (the "Evidence"), and its appendices A through G. I have also reviewed portions of NB Power's IR responses to the Public Intervenor and the other parties in EL-002-2025, as well as a number of relevant publicly available documents.

II. Executive summary

Q8. Please summarize your findings and recommendations for the Board.

A8. The proposed Renewable Integration and Grid Security Project (RIGS) generation is not justified using current planning standards and conditions. The Board should not approve this project. This opinion is based on these findings:

1. The most recent Maritimes Area resource adequacy review study shows that NB Power has enough resources available without the RIGS generation to meet or exceed its planning requirements through 2030. The RIGS project cannot be justified by regional planning criteria and studies.

2. Delaying NB Power's planned 111 MW net generating capacity reductions until 2029 will provide more time to develop better alternatives and long-term solutions.

3. NB Power relied on operating-type analyses, together with planning studies, to support its plans—such operating analyses are not appropriate for determining capacity expansion plans.

4. NB Power has summarily dismissed energy storage as a reasonable solution; one that would be more flexible, provide additional

benefits beyond those offered by the RIGS project, and could result in lower costs for New Brunswick customers.

5. NB Power's capacity sales are a key part of its claimed need for the RIGS project. The most recent Maritimes area adequacy review study shows there will be enough capacity in the Maritimes to meet the area's needs, giving NB Power alternatives to meet these obligations without the RIGS generation.

III. Description of the project

Q9. What is NB Power proposing in this matter?

A9. NB Power seeks approval for its plans to acquire capacity, energy, and ancillary services from a dual-fuel combustion turbine (CT) generation facility with a maximum capacity of 400 MW (eight 50 MW CTs) to be installed in New Brunswick through a tolling agreement with RIGS Energy Atlantic Limited Partnership to fulfill NB Power's claimed resource adequacy needs.[1]

1. Evidence, page 5, lines 26-30.

IV. Resource adequacy and the need for the project

Q10. How did NB Power determine its resource adequacy needs?

A10. NB Power's Resource Adequacy Report found that 400 MW of additional capacity will be needed by 2028.[2] In a brief seven-page report (Evidence Appendix A), NB Power presents its resource adequacy assessment for the 2025-2030 period. Reports used to justify annual costs exceeding $100 million are usually more extensive, with considerable technical, cost, and financial information, as well as a detailed comparison of available options.

Q11. What did NB Power find in its resource adequacy assessment?

A11. NB Power presented its results in a two-part table (Table 1) in Appendix A to the Evidence, on page 6. The first part presents a "Load and Resource Balance" calculation, while the second presents an "Operational Requirement" calculation. NB Power determined the need for added capacity using the method that found the largest capacity shortfall.

Q12. What is your initial response to the adequacy assessment?

A12. NB Power has mixed together planning and operating criteria and standards in defending its resource addition plans. This is a problem because each of these serves different purposes and uses different study tools, assumptions, and applications.

2. Evidence, page 4, lines 10-11.

There is also an interesting interplay between NB Power's roles as the Reliability Coordinator and the Balancing Authority for the Maritimes region, and operator of its own system.

The matter before the Board results from a planning study intended to justify NB Power's proposed expansion of its supply resources for 2028 to strengthen its system. It is not an operating study.

In addition, there is the October 2025 study of the adequacy of the Maritime resources that shows there is no need for the RIGS generation.

Q13. How are planning and operating studies different?

A13. While both aim for the same goal—a safe and reliable power system—they differ in their time frames, levels of uncertainty about future conditions, assumptions, analysis tools and methods, and criteria and standards applied. Operating plans and studies range from real-time conditions, hourly and week-ahead assessments, to forecasts up to 18 months in advance. Operating studies are deterministic and address conditions with greater certainty than planning studies. Planning studies are probabilistic, incorporating a wide range of uncertainties and conditions related to customer load, available generation resources, and the system's transmission configuration. The uncertainties are higher in planning studies that must span up to 20 years into the future.

Perhaps most importantly, utilities conduct planning studies to design, expand, and strengthen the power system to meet future needs over a period of years or decades. Operating studies are carried out to ensure the grid functions safely and reliably on a daily or hourly basis, using the resources available at the time of the study.

Q14. But doesn't NB Power have to meet both the planning and operating criteria and standards?

A14. Yes, but each lies within its own domain with its own set of applicable conditions, assumptions, tests, and standards of acceptable performance.

NB Power has asked the Board for approval to expand the power system by adding 400 MW of CTs. It claims this is necessary to meet system needs by 2028, three years in the future, beyond the normal 18-month operating study horizon. The *Electricity Business Rules*, Chapter Three, *Reliable Operations,* outline the requirements of the Resource Adequacy Assessment.[3] While the assessment has a look-ahead feature, it is an operating study, not a planning study. In addition, NB Power states that they must have contingency reserves to provide for its "Most Severe Single Contingency."[4] This is a reference to the North American Electric Reliability Corporation (NERC) Reliability Standard BAL-002-3, *Disturbance Control Standard –*

3. NB Power, *New Brunswick Electric Business Rules*, dated 1 October 2013 (NBP8.48).

4. The Evidence, page 9, lines 25-30.

Contingency Reserve for Recovery from a Balancing Contingency Event, an operating standard. The specific quote that NB Power includes in its Evidence is applicable to a "Responsible Entity". The NERC Standard specifically states that a Responsible Entity is a Balancing Authority, not an individual utility like NB Power.[5]

This Standard's purpose is:

> *"To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event."*[6]

In this case, the Standard applies to the Maritimes Balancing Area, which includes New Brunswick, Nova Scotia, and Prince Edward Island.[7] The Standard applies to the Balancing Area, not the individual systems. NB Power has misapplied it in their filing.

5. NERC Reliability Standards for the Bulk Electric Systems of North America, 24 October 2024, BAL-002-3, A.3, page 1 of 7.

6. Ibid., footnote 5.

7. The Northeast Power Coordinating Council (NPCC) defines the Maritime Provinces as New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator, NPCC, *Reliability Assessment for Winter 2025-2026*.

Because the matter before the Board is the result of a planning study aimed at expanding and strengthening the system, planning methods, criteria, procedures, and results should be the primary determinants of the need for the proposed project.

Q15. What is the Northeast Power Coordinating Council (NPCC)?

A15. The NPCC website states:

> "[The NPCC] *is a not-for-profit corporation in the state of New York responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America… NPCC is committed to the collective vision of a highly reliable and secure North American bulk power system and shares the joint mission of assuring the effective and efficient reduction of risks to the reliability and security of the grid.*
>
> *The NPCC geographic region includes the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia."*[8]

Q16. How does the NPCC relate to NB Power's expansion plan in this matter?

A16. The NPCC develops regional reliability standards and compliance assessments, enforces continent-wide and regional reliability standards, coordinates system planning, design and operations, and assessments of reliability.

8. NPCC website, accessed 28 November 2025, https://www.npcc.org/about.

NB Power uses the NPCC planning standard of no more than a 0.1-day/year loss-of-load expectation (LOLE) as the basis for its minimum reserve margin requirement of 20% when evaluating resource adequacy.[9] The NPCC sets this standard in its *Regional Reliability Reference Directory # 1, Design and Operation of the Bulk Power System,* 2 July 2024, Requirement 'R4', page 6.

This NPCC document states:

> *"The objective of this Directory is to provide a 'design-based approach' to design and operate the bulk power system to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system… The characteristics of a reliable bulk power system include adequate resources and transmission to reliably meet projected customer electricity demand and energy requirements as prescribed in this document."*[10]

Directory # 1 later adds:

> *"A Comprehensive Review of Resource Adequacy is required every three years and will cover a time period of five years… In subsequent years, each Planning Coordinator shall conduct an Annual Interim Review of Resource Adequacy that will cover, at a minimum, the remaining years studied in the Comprehensive Review of Resource Adequacy."*[11]

9. Appendix A to the Evidence, page 2.
10. NPCC Directory #1, §1.3, page 4.
11. NPCC Directory #1, §3.0, R5.2 and R5.3, page 7.

The NPCC's most recent Comprehensive Resource Adequacy review of the Maritimes area was issued in October 2025, consistent with this Directory.[12]

Q17. How has NB Power implemented these NPCC requirements?

A17. NB Power uses a 20% reserve margin based on a probabilistic analysis of the Maritime Provinces' LOLE.[13, 14] The calculation mathematically combines the probabilities of the load and resources to determine the expected number of hours when the resources would be insufficient to meet the NPCC's standard, when firm customer load might have to be shed.

This 20% reserve margin is used in planning to ensure sufficient 'spare' generating capacity to handle uncertainties such as customer load fluctuations, weather variability, outages of generation resources, and similar events. This reserve margin is the standard NB Power relies on to evaluate the adequacy of future plans.

12. NPCC, New Brunswick Power Corp., Nova Scotia Power Incorporated, Maritime Electric Company, Limited, Northern Maine ISA, Inc., *2025 Maritimes Area Comprehensive Review of Resource Adequacy*, October 2025. (NBP8.06)

13. The Northeast Power Coordinating Council (NPCC) defines the Maritime Provinces as New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator, NPCC, *Reliability Assessment for Winter 2025-2026*.

14. Evidence, Appendix A, page 2, §2 Planning Reserve Margin.

Q18. What are NB Power's roles as a local system operator, Balancing Authority, and Reliability Coordinator for the Maritimes region?

A18. NB Power has three system functions: the first is as the Balancing Authority for the Maritimes, the second is as the Reliability Coordinator for the Maritimes, and the third is as the operator of the NB Power electric system.

As the Balancing Authority, NB Power oversees the reliable operation of the Maritimes Area (New Brunswick, Nova Scotia, Prince Edward Island, and Northern Maine).[15] The New Brunswick transmission grid is the hub of the Maritimes Area and is also interconnected with New England and Québec. NERC defines the Balancing Authority as the "*responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time.*"[16]

As the Reliability Coordinator, NB Power is the entity with the highest level of authority responsible for operating the Bulk Power System. It has a wide-area view of neighboring utilities. Reliability Coordinators have the authority, operating tools, processes, and procedures in place to prevent or mitigate emergency operating situations, thereby maintaining system reliability and keeping the lights on. NERC

15. Adapted from "Transmission System Operator", https://tso.nbpower.com/Public/en/op/, accessed 12/31/25.

16. North American Electric Reliability Corporation (NERC), "Glossary of Terms Used in NERC Reliability Standards", updated 5 November 2025.

adds that the "*Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.*"[16]

As the NB Power system operator, NB Power is the vertically integrated electric utility responsible for the generation, transmission, and distribution of electricity in its service territory. NB Power serves all residential and industrial power consumers in New Brunswick, except those in Saint John, Edmundston, and Perth-Andover. In this role, NB Power is responsible for the reliability of its 'local' transmission, generation, and distribution systems and operates or directs the operations of these facilities. Like the other Maritime area utilities, NB Power has exclusive control of the economic dispatch for its system.[17]

I.1 NB Power's justification of the need for new capacity resources

Q19. How did NB Power make its planning load and resource balance calculation?

A19. NB Power first justifies the need for new generating capacity based on their planning reserve margin.[18] Table 1 shows their planning load and resource balance calculation based on Table 1 on page 6 of Appendix A to the Evidence. During the five-year period, the load increases by 27 MW, the conventional resources decrease by 201 MW,

17. NPCC, New Brunswick Power Corp., Nova Scotia Power Incorporated, Maritime Electric Company, Limited, Northern Maine ISA, Inc., *2025 Maritimes Area Comprehensive Review of Resource Adequacy*, October 2025, page 3, §2.2. (NBP8.06)

18. See pages 2-4 of Appendix A to the Evidence.

and the shortfall grows from 27 MW to 264 MW. NB Power claims that the system fails the adequacy test each year, mainly due to reduced conventional resources.

Table 1: Resource adequacy, resource balance calculation, NB Power original[19]

Year	2025	2026	2027	2028	2029	2030	Change
Capacity requirement							
Peak load	3,223	3,224	3,225	3,234	3,242	3,250	27
Less interruptible load	110	110	110	110	110	110	0
Total peak load requirement	3,113	3,114	3,115	3,124	3,132	3,140	27
20% reserve	649	649	649	650	651	653	4
In-province requirement	3,762	3,763	3,764	3,773	3,783	3,793	31
Export capacity contracts	401	410	410	402	402	402	1
Total requirement	4,163	4,173	4,174	4,175	4,185	4,195	32
Resources available							
Conventional resources	3,969	3,972	3,972	3,860	3,860	3,768	-201
Wind	162	162	162	162	162	162	0
Total resources	4,131	4,133	4,133	4,022	4,022	3,930	-201
Capacity shortfall							
Shortfall	32	39	40	153	163	264	232

Q20. Do you see any problems with this calculation?

A20. Yes, I see at least five problems: 1) the results from the most recent Maritimes resource adequacy report, 2) the treatment of the export contract amounts, 3) the mixing of operating and planning standards to justify resource planning, 4) how NBP

19. Source: Table 1 of Appendix A to the Evidence, page 6.

calculates the reserve margin, and 5) determining the capacity credit for energy storage resources.

Q21. What is the impact of the most recent Maritime resource adequacy report?

A21. NB Power provided several of these reports in NBP8.06. The most recent Maritimes resource adequacy report is the *2025 Maritimes Area Comprehensive Review of Resource Adequacy*.[20] This report and associated studies, which included participation by NB Power, preceded the NB Power filing in matter EL-002-2025 on 31 October 2025. The report showed that, while the Maritimes does not meet the 0.1 days/year LOLE criteria in 2026 and 2027, it easily meets this criterion beginning in 2028.[21] In addition, it will far exceed the 20% reserve margin every year from 2028 through 2030.[22]

Q22. Do these reserve margins and LOLE results include the RIGS units?

A22. Yes. The study assumed the addition of 400 MW of CTs in the NB Power system, but not until 2029. The RIGS units were not part of the 2028 study year, when the LOLE was 0.046 days/year and the reserve margin was 29%, exceeding the minimum adequacy planning requirements.

20. NPCC, New Brunswick Power Corp., Nova Scotia Power Incorporated, Maritime Electric Company, Limited, Northern Maine ISA, Inc., *2025 Maritimes Area Comprehensive Review of Resource Adequacy*, October 2025. (NBP8.06)

21. Ibid. footnote 20, page 6 and Table 4.

22. Ibid. footnote 20, Table 5.

Q23. Are the RIGS units necessary to maintain the reliability of the Maritime area?

A23. No. Table 5 in the 2025 comprehensive report presents the forecasted reserve margins for 2026-2030. If the 400 MW of RIGS generation is not added in 2029, there will still be ample reserves in the Maritimes through 2030, as shown in Table 2. Table 2 is based on Table 5 on page 9 of the 2025 report. Without the RIGS, the forecasted Maritime Area reserve margins would be 29% in 2028, and fall from 37% to 30% in 2029, and from 60% to 53% in 2030. These levels are well above the 20% required minimum reserve margin for the Maritimes.

Table 2: Estimated Maritime Area reserves without the RIGS generation

January	Forecast capacity	Peak load	Inter. Load	Forecast reserve	
	MW	MW	MW	MW	%
2026	7,366	6,178	273	1,461	25
2027	7,219	6,296	273	1,196	20
2028	7,625	6,202	273	1,696	29
2029	7,652	6,166	273	1,759	30
2030	9,074	6,202	273	3,145	53

$$\text{Forecast reserve} = \frac{(\text{forecast capacity} - (\text{peak load} - \text{inter. load}) \times 100\%}{(\text{peak load} - \text{inter. load})}$$

Q24. What about the resulting LOLE without the RIGS units?

A24. The impact of removing the RIGS generating units on the Maritime's LOLE can be extrapolated from Tables 4, 6, 7, and 8 in the 2025 study report.[23] These tables show the LOLE for the base case, the high-load case, the 50% wind-deration case, and the no-tie-benefit case, respectively. The highest LOLE for 2029 or 2030 in any of these cases is 0.008 days/year; well below the 0.1 days/year criterion. This was the case without 300 MW of imports into the Maritime Area. The LOLE worsens from 0.001 in the base case to 0.008 days/year. If we use this difference to extrapolate the LOLE without the RIGS units, it becomes 0.010 days/year.[24] This is much better than the required minimum LOLE of 0.1 days/year.

The Maritimes would easily meet their LOLE requirement and their reserve margin requirement without the RIGS generation.

Q25. How does this fit with your concern about the interplay between NB Power's roles as a system operator and as the Balancing Authority and Reliability Coordinator for the Maritimes region?

A25. Most of the work presented in NB Power's Evidence addresses NB Power's stand-alone system's reserve needs without considering the Maritime area's reserves. The key calculation tables NB Power relies on in EL-002-2025 are from an NB Power

23. Ibid. footnote 20, pages 6, 10, 11 and 12.

24. The calculation is: $\frac{0.008-0.001}{300} \times 400 + 0.001 = 0.010$.

system perspective. Perhaps the most prominent among these is Table 1 in Appendix A to the Evidence—Resource Adequacy Calculations 2025 to 2030. This table includes the *"load and reserve balance calculation"* and the *"operational requirement calculation"* for the stand-alone NB Power system.

This also relates to NB Power's role as the Balancing Authority and Reliability Coordinator.

Q26. How does this relate to NB Power's role as the Maritime Area's Balancing Authority and Reliability Coordinator?

A26. The Public Intervenor's IR-01f asked what conditions would allow curtailing capacity sales contracts listed in Table 1 of Attachment A to the Evidence. NB Power responded that firm export contracts could not be curtailed under normal conditions. Curtailments of such firm service can occur only when there is a shortage of transmission or generating capability in the Maritime Area that would jeopardize system reliability.

Regarding a possible shortage of generating capacity, they referred to the NERC reliability standard EOP-011-4 and added:

> *NB Power, in its role as Reliability Coordinator for the Maritimes Area, may respond to operating emergencies with curtailment actions to prevent the failure of generation supply that could adversely affect the reliability of the Bulk Electric System.* (NBP8.21, page 4)

They make clear that a curtailment would occur only as directed by the Reliability Coordinator. The Reliability Coordinator is responsible for the entire Maritime Area.

Generating capacity-related curtailments would be possible only when there is a shortage of generation supply across the entire Maritime Area.

Thus, firm sales could be curtailed only when there is a capacity shortage across the entire Maritime Area, not just within NB Power. Table 2 shows that the Maritime Area has sufficient generating capacity to meet its 20% reserve requirement even without the RIGS generation. So, even if NB Power did not have enough capacity to meet its obligations, service could not be curtailed so long as the Maritime Area has enough capacity.

As Table 2 showed, even without the RIGS generating units, the operating reserve of the Maritimes Area would be no lower than 29% (2028) and as high as 53% (2030). These are not conditions where a capacity emergency is likely. In addition, answer A24. showed that the Maritimes Area would comfortably meet its LOLE criteria in each year from 2028 through 2030 without the RIGS generating units.

Q27. Is there any other issue with Table 1 that is important?

A27. Yes, the 201 mw decline in total resources. This reduction is due to changes in conventional resources. Since the Maritime's resources will be adequate from 2028 through 2030, this affects only NB Power's stand-alone situation. As the table shows, conventional resources fall from 3,969 mw in 2025 to 3,860 mw in 2028, a net reduction of 109 mw. This reduction is mostly due to the 112 mw reduction at

Mactaquac, from 668 mw to 556 mw, due to its Life Achievement Project in 2027-28. Delaying this by one year would add flexibility and increase NB Power's resources.

Q28. You formed some strong opinions based on the 2025 Maritimes resource adequacy report. Who prepared this report?

A28. The report was prepared by the Maritime utilities under the auspices of the NPCC. Specifically, New Brunswick Power Corp., Nova Scotia Power Incorporated, Maritime Electric Company, Limited, and Northern Maine Isa, Inc. are listed as authors. The report is dated October 2025, so the work was likely being done at the same time as some of the work for this filing.

Q29. How does the 2025 Martimes resource adequacy report show that there should be enough capacity available for NB Power to "firm up" any sales in the event that they fall short?

A29. Table 2 shows the Maritime generating reserves excluding the RIGS' generation. The reserve margin is 29% in 2028, 30% in 2029, and 53% in 2030, all of which exceed the 20% minimum requirement. This means that 9%, 10%, and 23% of reserve margin would be available, respectively. This translates to nearly 560 MW in 2028, 620 MW in 2029, and more than 1,400 MW in 2030. If NB Power foresaw a period when it would be unable to fulfill its 402 MW sales obligation with internal resources, there should be ample capacity to purchase.

Q30. Referring back to Table 1, what is the second problem you have with how NB Power treats the capacity sales?

A30. Although the Maritime Area has sufficient reserves, NB Power does not set aside reserves for these sales, as shown in Table 1. Therefore, NB Power assumes the required reserves are provided in the Maritime Area outside the NB Power system. (In such sales, it is common practice for the buyer to provide reserves for the purchases. In effect, the buyer is 'firming' the purchase.)

At least one of NB Power's sales contracts prohibits curtailment unless the entire Maritime Area firm load is curtailed, on a pro-rata basis.[25] This confirms that sales are firm while capacity is available across the entire Maritime Area. If NB Power did not have enough internal capacity to fulfill its sales obligations, it would be obligated to purchase the necessary capacity from elsewhere in the Maritime Area to avoid curtailing firm native load. Table 2 and A29. show that enough capacity will be available.

Without needing to supply ≈400 MW in sales from internal resources, the 400 MW of RIGS generation is not needed.

25. *Energy Purchase Agreement Between Maritime Electric Company, Limited, and New Brunswick Power Generation Corporation*, 1 March 2011, §3.1.b, provided in NBP8.23CR, pdf page 12.

Q31. What is NB Power's Operational Requirement justification for RIGS?

A31. They discuss this justification, Operational Requirements, on pages 4-5 of Appendix A to the Evidence. This portion of the NB Power justification is an operating-based approach that is not part of the NPCC Resource Adequacy process described in the NPCC's Directory #1.[26] The relevant sections address transmission operation and operational planning coordination with other utilities and Balancing Areas.[27]

Q32. What does Directory #1 require regarding resource adequacy?

A32. The Directory's objective is "*to provide a 'design-based approach' to design and operate the bulk power system to a level of reliability that will not result in the loss or unintentional separation of a major portion of the system from*" a specific list of contingency types.[28]

In discussing resource adequacy, the Directory specifies a minimum LOLE requirement of 0.1-days/year. It further specifies the need for comprehensive and interim reviews of resource adequacy on a three-year cycle, with each review covering a five-year look-ahead period.[29]

26. NPCC, *Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System,* dated 2 July 2024.

27. Ibid. 26, page 9 and Appendix F.

28. Ibid. footnote 26, page 4, §1.3.

29. Ibid. footnote 26, pages 7, §R5.2 and §R5.3.

The Directory provides additional guidelines in its Appendix D, which states the purpose of the resource adequacy reviews is to:

> *Show that each Planning Coordinator's proposed resources are in accordance with the NPCC Directory #1 - Design and Operation of the Bulk Power System. By such a presentation, the Task Force will satisfy itself that the proposed resources of each NPCC Planning Coordinator will meet the NPCC Resource Adequacy Requirements, as defined in NPCC Directory #1, over the time period under consideration.*[30]

NPCC adds that conformance with Directory #1 is:

> *Essential because under this criterion, each Planning Coordinator determines its resource requirements by considering interconnection assistance from other Planning Coordinators, on the basis that adequate resources will be available in those Planning Coordinator Areas. Because of this reliance on interconnection assistance, inadequate resources in one Planning Coordinator Area could result in adverse consequences in another Planning Coordinator Area.*[30]

These are all adequacy planning requirements that do not include operating requirements applicable to system planning.

30. Ibid. footnote 26, page 33, §2.0.

Q33. How did NB Power calculate the "operational requirement"?

A33. Table 3 shows this calculation based on Table 1 of Appendix A to the Evidence, page 6.[31] During the period, the load increases by 27 MW, conventional resources decrease by 201 MW, and the shortfall grows from 294 MW to 523 MW. The system fails the adequacy test each year, mainly due to reduced conventional resources.

Table 3: Resource requirement calculation, NB Power original

Year	2025	2026	2027	2028	2029	2030	Change
Capacity requirement							
Peak load	3,223	3,224	3,225	3,234	3,242	3,250	27
Less interruptible load	110	110	110	110	110	110	0
Total peak load requirement	3,113	3,114	3,115	3,124	3,132	3,140	27
Largest contingency reserve	715	715	715	715	715	715	0
In-province requirement	3,828	3,829	3,830	3,839	3,847	3,855	27
Export capacity contracts	371	380	380	372	372	372	1
Total requirement	4,199	4,208	4,209	4,211	4,219	4,227	28
Resources available							
Conventional resources	3,969	3,972	3,972	3,860	3,860	3,768	201
Wind	136	136	136	136	136	136	0
Unplanned outages	200	200	200	200	200	200	0
Total resources	3,905	3,908	3,908	3,796	3,796	3,704	201
Capacity shortfall							
Shortfall	294	301	302	415	423	523	229

31. Table 1 of the Evidence, Appendix A, page 6.

Q34. Ignoring the fact that this calculation does not apply to planning studies like that NB Power used to justify its capacity additions, do you see any other problems with this calculation?

A34. Yes, there is a problem with double-counting of unplanned outages.

The treatment of outages is somewhat simplified in the operational requirement calculation. The Balancing Authority must provide evidence and documentation that the Balancing Authority:

> *"determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency".*[32]

The Maritime Area Balancing Authority must be prepared for the loss of the "Most Severe Single Contingency" defined as:

> *"The Balancing Contingency Event, due to a single contingency identified using system models maintained within the… Balancing Authority's area… that would result in the greatest loss (measured in MW) of resource output used by the… Balancing Authority… at the time of the event to meet Firm Demand and export obligation[s]".*[33]

32. NERC Reliability Standards for the Bulk Electric Systems of North America, 24 October 2024, BAL-002-3, measure M2, page 3.

33. North American Electric Reliability Corporation, "Glossary of Terms Used in NERC Reliability Standards", updated 5 November 2025.

This is a clear requirement from the NERC Standards adopted by and included in the NPCC criteria. What is not included is that the Balancing Area must also allow for additional unplanned outages.

NB Power's calculations, as shown in Table 3, account for the "largest contingency reserve" and "unplanned outages". Neither of these terms appears in the NERC or NPCC standards. NERC defines the "Most Severe Single Contingency"; however, we can assume that this is the basis for NB Power's largest contingency reserve. NERC defines Most Severe Single Contingency as:

> *"The Balancing Contingency Event, due to a single contingency identified using system models maintained within the… Balancing Authority's area… that would result in the greatest loss (measured in MW) of resource output used by… a Balancing Authority… to meet Firm Demand".*[34]

Note that NERC refers to this in the context of the Balancing Authority.

The second term, unplanned outages, is an NB Power term that seems to refer to random outages or derations of generation resources that occur during normal system operation.

34. North American Electric Reliability Corporation (NERC), "Glossary of Terms Used in NERC Reliability Standards", updated 5 November 2025.

Regardless, this is double-counting these two items; the outage of the largest generating unit simultaneously, on top of additional unplanned outages by NB Power is not part of the NERC or NPCC standards.

It is inconceivable that NB Power would *plan* an outage of its largest unit (i.e., the largest contingency reserve) during the system's peak-demand season. So, this 715 MW loss would be unplanned. Adding another 200 MW of unplanned outages is unduly burdensome and unnecessarily increases customer costs.

The treatment of the 715 MW Point Lepreau unit is also an interesting inclusion by NB Power. With a peak load of about 3,200 MW, the Point Lepreau unit accounts for a little more than 22%. Allowing for the loss of that one unit, together with NB Power's other generation, would require a reserve margin of much more than 20%. Yet, as discussed earlier, the Maritimes Area has adequate capacity with a 20% reserve.

This is because the Point Lepreau unit accounts for only about 11% of the Maritime Area's load, which exceeds 6,200 MW. Moreover, the requirement for the most severe single contingency applies to the Maritime Area, its Balancing Authority and Reliability Coordinator, not to the NB Power system.

By including it in their calculation, NB Power has increased capacity requirements beyond those needed to meet any of the reliability criteria and standards presented. This unnecessarily increases the cost to NB Power customers.

I.2 Alternatives considered

Q35. What supply alternative did NB Power consider?

A35. Section 3 of the Evidence and sections 9 and 10 of Appendix C to the Evidence address supply alternatives. NB Power considered conventional fuel-based resources, imports from neighboring systems both inside and outside of the Maritimes, and non-fuel options including wind, solar, and energy storage.

Q36. What fuel-based resources did NB Power consider?

A36. NB Power considered simple-cycle combustion turbines and combined-cycle plants.

Simple-cycle combustion turbines (CTs) are similar to the jet engines used in aircraft. They burn natural gas or light oil in a rotary compressor system to power an electric generator attached to the spinning turbine shaft. Their main advantages are quick start-up and shutdown, rapid output changes, and relatively low installed costs. Their main disadvantages are lower fuel efficiency compared with other resources and the use of carbon-based fuels. The economic trade-off is lower installed cost against higher operating costs. Their high operating costs make them most often used as peaking resources. This is the resource option selected by NB Power for the RIGS generation.

A related type of resource is the combined-cycle plant. The 'combined' moniker comes from the plant's combination of simple-cycle CTs with a heat-recovery steam turbine system. Combustion turbines release hot exhaust gases. A combined-cycle plant captures this heat and uses it to produce steam for use in an otherwise conventional steam-generating unit. The most common configuration uses two CTs with a single steam unit. The main advantages of a combined-cycle plant are its very high efficiency and, to a lesser extent, the flexibility to operate in various combinations of CTs and steam generation. The main disadvantage is its higher installed cost compared with simple-cycle CTs. NB Power did not select this resource because, although it is most economically efficient as a base-load unit, NB Power claims it does not need additional base-load capacity.

Q37. What imports did they consider?

A37. NB Power considered purchases from its Maritime neighbors, Quebec, New England, and Labrador. In each case, NB Power concluded that either generating or transmission capacity would not be available.

While this may have been true when NB Power evaluated these options in 2024, the 2025 resource adequacy report indicates that the Maritime Area will have more than enough capacity to meet its planning criteria.[35] As already discussed, this means capacity should be available for purchase should NB Power need it. By meeting the

35. NPCC, New Brunswick Power Corp., Nova Scotia Power Incorporated, Maritime Electric Company, Limited, Northern Maine ISA, Inc., *2025 Maritimes Area Comprehensive Review of Resource Adequacy*, October 2025, pdf page 40. (NBP8.06)

NPCC planning criteria, the Maritimes showed that "adequate resources will be available".[36]

Q38. How does NB Power address non-fuel-based resource additions?

A38. Section 3.2.1 of the Evidence briefly addresses wind, solar, and battery options. While included under the heading of intermittent resources, only wind and solar are intermittent. Batteries are not intermittent resources, like hydroelectric plants; they are energy-limited. NB Power's discussion focuses on ELCC of batteries.

Q39. What is ELCC?

A39. Effective load-serving capability (ELCC) dates to work done by Len Garver of GE in the early 1960s. The seminal work on the subject was published in 1966.[37] The probabilistic method measures the benefit of adding a resource to a system. In the context of this matter, the ELCC is the maximum load the Maritimes can carry while meeting its 0.1 days/year criteria. This standard is the basis for the 20% reserve margin requirement; however, it is the LOLE that is the standard for the Maritimes.

Adding a resource, such as RIGS, to the Maritimes system will increase its ELCC. A new LOLE study with the new RIGS generation would show how much the load could

36. NPCC, *Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System,* dated 2 July 2024, page 7, §R6.

37. L.L. Garver, *Effective Load Carrying Capability of Generating Units*, IEEE Transactions on Power Apparatus and Systems, Vol. PAs-85, No. 8, August 1966, page 910.

increase before reaching an LOLE of 0.1 days/year. The resulting increase would be the RIGS project's ELCC.

Q40. How does NB Power use the ELCC approach shown in Figure 2 of the Evidence to compare wind, solar, and battery resources with its proposed CT option?

A40. NB Power discusses its use of ELCC at some length on pages 45-46 of Appendix C to the Evidence. They make several points that are both true and misleading. For instance, they make the following true statement that is also misleading:

> *"NB Power contracted Energy and Environmental Economics (E3) to do an effective load carrying capability (ELCC) study on wind, solar and batteries. ELCC is the measure of the ability for a unit to provide capacity to the grid. Traditional generation sources like hydro and thermal resources provide reliable capacity up to their unit maximum capability while non-dispatchable or limited dispatchable units provide less firm capacity to the grid than their installed capacity."*[38]

Q41. How is this statement misleading?

A41. They compare 'traditional' generating resources using their maximum capacity with the ELCC of non-dispatchable resources. An approach like this is used by independent system operators (ISOs) such as the NPCC and others. This is a

38. Appendix C to the Evidence, page 45.

convenient shortcut for evaluating the reliability benefits of new generating resources when an ISO is faced with hundreds of proposed non-dispatchable resource projects.

It is not appropriate when comparing two specific resource options.

Q42. How would ELCC be applied in comparing two specific options?

A42. An ELCC study would be made using the technical characteristics of the resource under study, the characteristics of the existing fleet of resources, and the system load shape. Resources with high availability will have a higher ELCC than those with lower availability. For example, the availability of a nuclear unit is much higher than that of a solar resource.

A system load shape with a high peak-to-average load ratio will produce a different ELCC than one with a lower peak-to-average load ratio. Also, how a resource's daily and hourly output profile corresponds with the daily system load shape affects its ability to serve the system load. This is particularly important for solar resources, whose output rises and falls with the sun, while NB Power's system winter-peak load occurs around sunrise.

The concept of ELCC is most often used to assess the benefit of adding different types and sizes of resources. This appears to be what E3 has done. The method uses a probabilistic computer model to estimate how much additional load the system can handle as a result of the new resource. The ELCC may be measured by LOLP, LOLE, or LOLH, depending on which is used by the utility.

Consider a 300 MW combined-cycle unit addition. Recognizing the forced outage rate, partial outage rate, and maintenance times, such a resource might have an ELCC of 250 MW. That is, the system load could increase by 250 MW before reaching the probabilistic reliability standard.

Q43. How has NB Power used ELCC?

A43. They used it to show the impact of adding wind, solar, and battery resources to their system. NB Power discusses this on pages 45-46 of Appendix C to the Evidence:

> *"The study shows the declining effective capacity of these resources as they grow in size. While the initial amounts of generation are reasonably beneficial to the reliability of the New Brunswick system, as they grow in size that benefit declines on a per unit basis."*

And

> *"The analysis shows that the first 250 MW of batteries provide almost full capacity value, as the installed capacity increases the reliability benefits decrease as we enter diminishing returns."*

The presentation concludes with a figure showing how the ELCC increases for wind, solar, and batteries as their installed amounts increase.[39]

39. See Figure 2 of the Evidence or Figure 9-2 in Appendix C of the Evidence.

Q44. Is there a problem with how NB Power uses ELCC?

A44. Not in itself. As discussed above, what they present is true but misleading.

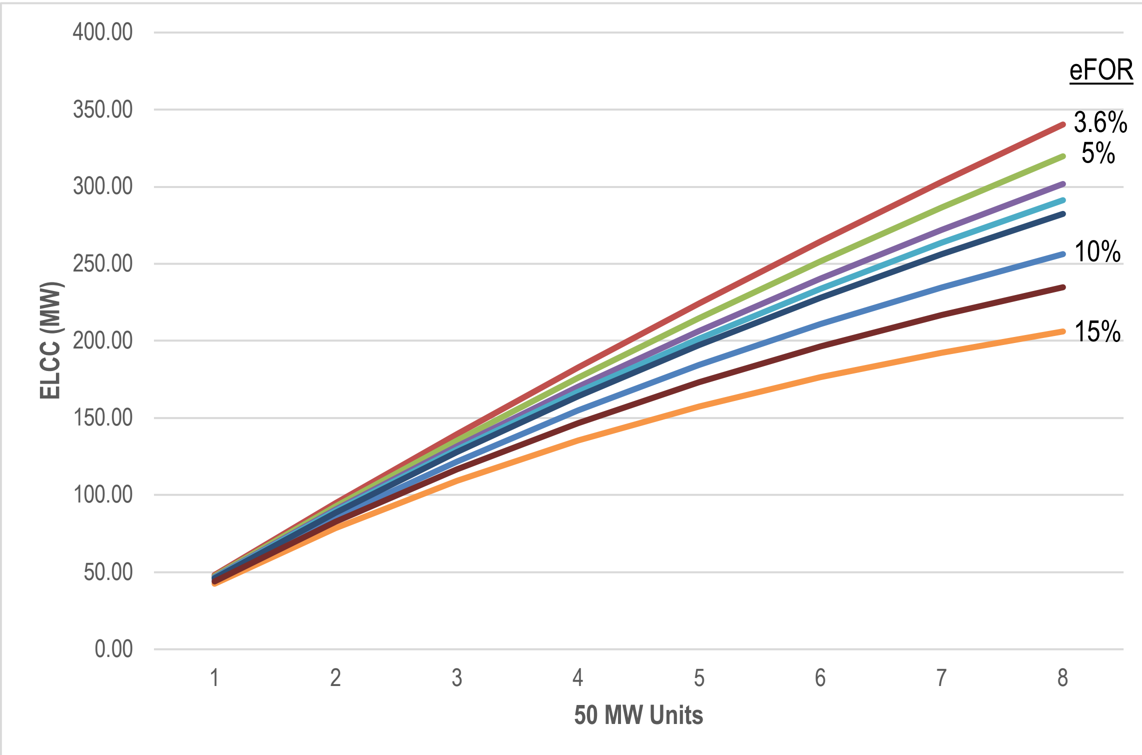
The determination of ELCC appears to be correct. What NB Power does not do is compare the ELCC of the wind, solar, and battery options with the ELCC of the proposed 400 MW CT plant.

Regarding batteries, they point out that each increase in capacity provides diminishing returns. This applies to all resource additions, not just batteries.

There is another factor that applies to the proposed 8 x 50 MW, CT option. The incremental ELCC will decline with each added unit. Consider 50 MW CTs with an availability of 90% (10% forced outage rate). Each unit could, on average, contribute 45 MW. However, the contribution to ELCC will decrease with each additional unit, as shown in Figure 1. The figure shows the effect on estimated ELCC with varying equivalent forced outage rates (eFOR).[40] The eFORs shown range from 3.6% to 15%.

40. The eFOR accounts for full outages (forced outage rate) and partial outages that occur.

Figure 1: Estimated ELCC with added 50 MW CTs



The ELCC will be highly dependent on the assumed eFOR. A brief scan of the internet yielded a wide range of reasonable eFORs for CTs—from 3.5% to 15.3% as shown in Table 4. Considering the MISO and ERCOT estimates, the eFOR for NB Power's proposed refurbished 50 MW CTs could be 10%

Table 4: Simple-cycle CT forced outage rates

Source / Size / Duty	FOR or eFOR value
From U.S. Energy Information Administration (EIA) "Combustion turbine" category (general) [41]	~ 3.6 % (0.036)
From Midcontinent Independent System Operator (MISO) study: CT units by size[42]	• 0-20 MW: ~ 23–40% • 20-50 MW: ~ 6.3–15.3% • 50+ MW: ~ 4.1–5.2%
From Electric Reliability Council of Texas (ERCOT) asset class averages, Gas combustion turbine [43]	10.0%
Federal Energy Regulatory Commission (FERC)[44]	7.8%
From a modelling dataset (natural gas – combustion turbine)[45]	3.5% FOR, with mean outage duration ~51 h

Table 5 shows the estimated resulting ELCC of 8 x 50 MW CTs. In the best case, the ELCC is 340 MW and, in the worst, 203 MW. A typical range for eFOR is from 5% to 10%, though some may be higher or lower. For aero-derived CTs, the type proposed for the RIGS units, an eFOR of about 5% is common.

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41. U.S. Energy Information Administration, *Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2022*, September 2022, Table 2-1, page 47, https://www.eia.gov/outlooks/aeo/nems/documentation/renewable/pdf/RFM_2022.pdf.

42. Joundi , Zakaria, et. al., Executive Director, Market & Grid Strategy, Midwest System Operator (MISO), *Prepared Direct Testimony, Motion to Intervene and Request for Rehearing and Stay of Public Interest Organizations*, before the Federal Energy Regulatory Commission (FERC), Order No. 202-25-7, filed 5 September 2025, https://www.energy.gov/sites/default/files/2025-09/Exhibits 81 - 100.pdf.

43. Preston, Eugene G., *ERCOT Generation Adequacy Study final report*, 18 March 2002, page 5, https://www.ercot.com/files/docs/2002/05/16/tac04042002_5.pdf.

44. Pfeifenberger, Johannes P., et. al., *Resource Adequacy Requirements: Reliability and Economic Implications*, prepared for FERC, September 2013, Table 16, page 135.

45. Reeve, Hayden M, et. al., *DSO+T: Integrated System Simulation, DSO+T Study: Volume 2*, January 2022, page 19, https://www.osti.gov/servlets/purl/1842488.

In this case, eight 50 MW CTs with a 5% outage rate would have an ELCC of about 320 MW. The 8 x 50 MW CTs, with a rated capacity of 400 MW would likely have an ELCC of about 320 MW.

With a typical eFOR for CTs of 10%, the ELCC would be about 260 MW.

Table 5: Estimated ELCC of 8 x 50 MW CTs

eFOR (%)	Expected ELCC (MW)
3.6	340
5	320
6.3	302
7.1	291
10.0	256
15.3	203

Q45. How does this affect the size of wind, solar, and batteries needed?

A45. Setting aside that Table 2 and A24. show that NB Power does not need any new resources, NB Power's Figure 2 in the Evidence can be used to estimate the amount of each type needed when ELCC is applied consistently.[46] The wind and battery amounts need to have comparable ELCC to the CTs as the assumed CT eFOR varies as shown in Table 6.[47]

46. NB Power provided more details for the figure in NBP8.08 in response to PI IR-05.

47. Solar is excluded because NB Power's estimated ELCC for solar is never enough to match the CTs ELCC.

Table 6: Equivalent amounts (ELCC) of CTs, wind, and battery

From Error! Reference source not found.		Size for equivalent ELCC (MW)[48]	
CT eFOR (%)	ELCC	Wind	Battery
3.6	340	1,940	600
5	320	1,610	560
6.3	302	1,410	490
7.1	291	1,320	460
10.0	256	1,040	380
15.3	203	730	250

NB Power stated that 1,000 MW/4,000 MWh batteries would be needed to be equivalent to the proposed CT option.[49] Table 6, however, shows that the equivalent ELCC for the CT option would probably be about half that amount, or less. With NB Power's claimed 5% eFOR, 560 MW of batteries would be needed; however, with the more common 10% eFOR, only 380 MW would be required.[50]

Q46. NB Power studied a 4-hour battery. Are there other battery options that would better suit NB Power's needs?

A46. Yes. NB Power assumed batteries with four hours of energy. Batteries, referred to in the industry as battery energy storage systems (BESS), are flexible regarding sizing. A

48. Based on Figure 2 in the Evidence and NB Power NBP8.08 in response to PI IR-05.
49. The Evidence page 21, lines 13-15.
50. In response to the Public Intervenor IR-03c, NB Power claimed FORs for the RIGS CTs would be 5% in NBP8.26.

BESS includes an inverter to convert between AC and DC, a power transformer to raise the BESS voltage to the system voltage, and a battery array. The inverter and transformer determine the MW output (capacity) of the system. The number and size of the battery units determine the BESS energy capability in MWh. More battery units provide more energy.

NB Power's response to PI IR-05 showed that the longest high-need period during Januarys and Februarys is 6 hours—from 05:00 to 12:00.[51] This implies that a 6-hour BESS would be much better suited to NB Power's needs. NB Power did not study a 6-hour BESS option. It seems obvious that it would be much better suited and would require a BESS system with lower capacities than those in Table 6.

While this is speculation, a 400 MW, 2,400 MWh BESS would probably be equivalent to the 400 MW RIGS resources with an ELCC of 310 MW. Another option that NB Power did not consider was 8-hour batteries.

Q47. Can you estimate the costs of the BESS's you discussed?

A47. Yes. The initial cost for a BESS is mainly determined by the amount of energy specified. The more batteries, the higher the capital (installed) cost.

51. See Interrogatory response NBP8.08, pdf page 3.

NB Power's *2023 Integrated Resource Plan* estimated Li-ion BESS levelized energy cost at 195/MWh.[52] This is about half the levelized cost of a CT at $389-418/MWh. The levelized capacity costs are comparable at about $20-23/kW-month.[53] These costs are rather old, dating to 2013, such comparisons depend on many variables, and there have been many technological advances that have reduced the costs of both. NB Power should make a more careful comparison of these options.

In total, however, a 6-hour or 8-hour BESS could be more economically competitive than the RIGS resources. Either BESS size would provide added benefits such as better response times that are nearly 1,000 times faster than a CT, voltage control with much lower operating costs, support services by acting like a STATCOM. Finally, they also complement wind generation, increasing their ELCC, and lowering system operating costs.

52. Attachment C to the Evidence, page 53.

53. Ibid, footnote 52,page 54.

V. Conclusions and recommendations

Q48. What are your general conclusions regarding NB Power's proposal?

A48. The information provided and the analyses presented here materially change the need for the proposed new capacity:

1. An important factor in NB Power's proposal is the apparent need for additional resource capacity in the next few years. This led to NB Power choosing refurbished CTs as a hurried solution.

2. NB Power used two methods to justify the claimed need. One uses an expansion-planning method, and the other uses an operational assessment method. Only the planning method applies to EL-002-2025.

3. Table 2 and answer A24. show that the Maritimes will have enough capacity resources without the RIGS resources to meet or exceed its planning requirements through 2030. The RIGS resources cannot be justified on a regional basis.

4. A primary cause of the 232 MW resource capacity shortfall claimed by NB Power is the 201 MW decrease in existing capacity (see Table 1). Delaying 112 MW of these reductions for one year would provide more time to develop better alternatives and long-term solutions.

5. NB Power considers capacity sales to neighboring systems as part of its resource requirements. While these sales may be labeled as 'firm', NB Power does not provide reserves for them and would not curtail its native customer load unless the entire Maritime Area were curtailing firm load. Even then, it would be on a pro-rata basis. Table 2 and answer A29. showed that the Maritimes will have enough capacity resources without the RIGS generation to meet its planning criteria. The RIGS resources should not be justified on an NB Power stand-alone system basis.

   The Board should not approve NB Power's addition of these unnecessary capacity resources at the expense of native-load customers.

6. In judging alternative solutions, NB Power has biased the results in favor of the CT proposal by comparing "apples and oranges." NB Power uses the full capacity of conventional generation (including the proposed CTs) in its resource calculations, while it applies a reduced ELCC measure for the capacity of wind and BESS. This unfairly disadvantages energy storage and, to a lesser extent, wind. Additionally, the reduced capacity credit for wind and energy storage increases the need for new capacity. When energy storage

and the RIGS resources are compared on an equivalent ELCC basis, energy storage has much lower levelized costs.

7. Even assuming that the claimed needs are justified, which they are not, there are BESS solutions that would meet NB Power's claimed needs and avoid adding most or all of the proposed CTs.

8. NB Power's resource adequacy calculations provide for the NPCC-required unplanned outage of NB Power's largest unit—715 MW at Point Lepreau. NB Power also includes another 200 MW of unplanned outages not required by the NPCC or the Energy and Utilities Board.

Together, these results delay the need for new capacity beyond 2030, allowing NB Power more time to evaluate alternative solutions that will be better in the long term.

Q49. Does this conclude your prepared direct testimony?

A49. Yes, it does.