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All the time.



June 10, 2026



Ms. Cheryl Bradley
Island Regulatory and Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Bradley:

***Response to Additional Interrogatories from Commission Staff
On-Island Capacity for Security of Supply Project (UE20742)***

Please find attached Maritime Electric's responses to additional interrogatories from Commission Staff with respect to the On-Island Capacity for Security of Supply Project Application and associated Supplemental Filing, filed with the Commission on December 18, 2024, and August 14, 2025, respectively.

In accordance with the Commission's letter of direction dated June 2, 2026, these interrogatory responses are accompanied by a sworn affidavit attesting to the truth of the evidence contained herein.

As indicated in Maritime Electric's update letter filed with the Commission on April 17, 2026 (Exhibit M-28), the updated ProEnergy budgetary proposal is valid until June 15, 2026, when the Equipment Contract Execution payment is due. After that date, Maritime Electric cannot guarantee that ProEnergy combustion turbine manufacturing slots will remain available or that the proposed project price and schedule will remain unchanged.

An electronic copy of this submission will be forwarded shortly.

Yours truly,

MARITIME ELECTRIC

A handwritten signature in blue ink, appearing to read "Michelle Francis".

Michelle Francis
Vice President, Finance & Chief Financial Officer

MR22
Enclosure



**RESPONSES TO ADDITIONAL INTERROGATORIES
FROM
COMMISSION STAFF**

**On-Island Capacity for Security of Supply Project
(UE20742)**

Submitted June 10, 2026



AFFIDAVIT

CANADA

PROVINCE OF PRINCE EDWARD ISLAND

**BEFORE THE ISLAND REGULATORY
AND APPEALS COMMISSION**

IN THE MATTER of Section 17(1) of the *Electric Power Act* (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for the approval of a 2024 Supplemental Capital Budget Request for the On-Island Capacity for Security of Supply Project.

AFFIDAVIT

I, T. Michelle Francis of Emyvale, in Queens County, Province of Prince Edward Island,
MAKE OATH AND SAY AS FOLLOWS:

1. I am the Vice President, Finance and Chief Financial Officer for Maritime Electric Company, Limited and as such have personal knowledge of the matters deposed to herein, except where noted, in which case I rely upon the information of others and in which case I verily believe such information to be true.
2. I prepared or supervised the preparation of the attached Interrogatory responses and to the best of my knowledge and belief the responses are true in substance and in fact.

SWORN TO at Charlottetown,
Prince Edward Island, the 10th
day of June, 2026.



A Commission for taking affidavits in the
Supreme Court of Prince Edward Island



T. Michelle Francis



INTERROGATORIES

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The Prince Edward Island Regulatory and Appeals Commission (the “Commission”), in assessing the Application by Maritime Electric Company, Limited (“Maritime Electric” or “MECL”) for approval of the On-Island Capacity for Security of Supply Project (the “Application”), requests responses to the following interrogatories from Maritime Electric:

IR-16 On April 17, 2026, Maritime Electric filed updated information about pricing and delivery timelines related to the ProEnergy opportunity.

- a. Provide the Net Present Value Inputs and Calculations and the Impact on Rate Base, Revenue Requirement and Customer Rates Calculations based on the updated pricing information for the ProEnergy opportunity.

Response:

The Net Present Value Inputs and Calculations and the Impact on Rate Base, Revenue Requirement and Customer Rates Calculations were filed as IR-16 - Updated Confidential Appendix B and IR-16 – Updated Confidential Appendix F, respectively, in Maritime Electric’s Supplemental Filing for the On-Island Capacity for Security of Supply Project (“Supplemental Filing”).¹

An Updated Supplemental Filing Confidential Appendix B and Updated Supplemental Filing Confidential Appendix F, with the project cost increased from \$334 million to \$353 million, is attached herein. The redactions approved in the Island Regulatory and Appeals Commission’s (the “Commission”) Order UE25-07A are maintained.

The updated estimated impact on customer rates is approximately six per cent for benchmark Rural Residential, Urban Residential and General Service customers.² As shown in the Updated Supplemental Filing Confidential Appendix F, the estimated impact on customer rates includes assumed avoided costs from the purchase of firm capacity from NB Power.

¹ Exhibit M-12, refiled with approved redactions as Exhibit M-25.

² Benchmark Residential Rural and Residential Urban customers include 650 kWh of consumption per month. Benchmark General Service customers include 10,000 kWh of consumption per month. Taxes are excluded from the impact on customer rates.

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IR-17 Provide additional information regarding the risks associated with the proposed deferral account and the potential for costs to be incurred if the project does not ultimately proceed.

- a. Describe scenarios where amounts recorded in the proposed deferral account may not proceed to a completed project, including circumstances beyond Maritime Electric's control such as supplier withdrawal, market changes, regulatory delays, supply chain disruptions, or changes in system needs.
- b. If the project does not proceed, indicate whether Maritime Electric intends to seek recovery from customers of all amounts recorded in the deferral account.
- c. Provide an assessment of the financial risks associated with the proposed deferral account, including the potential for stranded or unrecoverable costs.
- d. Provide details regarding the risks associated with ProEnergy withdrawing from the project, including any contractual protections or risk mitigation measures.

Response:

As indicated in Section 5.5 of the Accelerated On-Island Capacity Development Solution ("Supplemental Filing") and the Company's Response to IR-11 from Commission Staff, filed on January 15, 2026,³ Maritime Electric seeks approval to establish a deferral account for the following:

1. Slot Reservation Payment (progress payment #1) for USD \$6.24 million;
2. Equipment Contract Execution (formerly Full Notice to Proceed) payment of USD \$18.72 million;
3. Long Lead Procurement payment of USD \$18.72 million;
4. Owner's costs for permitting, site readiness, and transmission integration design which is estimated at CAD \$2 million in 2026;⁴
5. Additional costs necessary to maintain project momentum and alignment with NB Power's delivery schedule which are estimated at CAD \$1 million in 2026;⁵ and
6. Carrying costs calculated using the Company's weighted average cost of capital.

These expenditures are necessary to secure manufacturing slot reservations, maintain project schedule alignment and mitigate the risk of delays in addressing the capacity deficit; however, because they must be incurred before final project certainty is achieved, there is a financial risk to the costs incurred in the deferral account.

Maritime Electric notes that the purpose of the proposed deferral account is to provide regulatory assurance that costs prudently incurred to advance the Project - which is required to serve customers and address a growing capacity deficit - are recoverable from customers, subject to Commission prudence review and approval. To the extent that any amounts recorded in the deferral account are not refundable from ProEnergy under the terms of the applicable agreements or transferrable to another Commission-approved project, Maritime Electric would seek recovery of those costs from customers. It is Maritime Electric's understanding that, should the Commission

³ Exhibit M-18.

⁴ The Slot Reservation, Full Notice to Proceed, and Long Lead Procurement payment amounts listed represent the updated ProEnergy pricing, which were provided to the Commission in the Company's Capacity Pricing Update Letter, filed on April 17, 2026 (Exhibit M-28).

⁵ Additional costs may include internal costs related to labour, transportation, and other costs normally associated with the execution of capital projects.

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approve the deferral account as requested, the ultimate recovery from customers would be contingent on the Commission's assessment that the costs accumulated in the deferral account align with the evidence provided and the cost totals were prudent.

- a. Risks associated with the project and the deferral account were discussed in Section 7.0 Risk Analysis and Mitigation of Maritime Electric's Supplemental Filing.⁶ This response addresses the stated scenarios with a more detailed explanation.

A summary table of the risks and the associated financial implications of the deferral account, should the project not proceed, is provided in IR-17 – Attachment 1.

Supplier Withdrawal

If ProEnergy were to withdraw for reasons within its control, initial payments (Items 1–3) would be expected to be returned in accordance with contractual arrangements.⁷ In the case of Item 3, recovery may occur through the return of funds or through delivery of the associated long-lead equipment. Owner's costs (Item 4) would be transferable to a future project. Item 5 costs along with all carrying costs (Item 6), would not be recoverable from ProEnergy and would therefore be recoverable from customers, subject to a prudence review.

Maritime Electric considers this scenario to be unlikely, particularly given the recent approval of the NB Power Renewable Integration and Grid Security ("RIGS") project, which reinforces ProEnergy's commitment to projects in the region.

Market Changes or Availability of Alternative Capacity

If market conditions change such that the project is no longer economically viable – whether due to the availability of lower-cost, reliable and appropriate capacity resources or increases in the cost of the proposed solution – Items 1–3 would not be recoverable from ProEnergy.⁸ Items 4, 5 and 6 would not be transferable. Therefore, all costs would be recoverable from customers following a prudence review.

Maritime Electric notes that increases in project costs after initial commitments represent a potential risk in any capital project where there is a delay between early-stage payments and final contract execution. However, the structure of the proposed agreements with ProEnergy mitigates this risk; once the Gas Turbine Equipment Purchase and Sale Agreement is executed, pricing for the equipment is contractually established and is not

⁶ Exhibit M-12 and refiled as Exhibit M-25 following the Commission's confidentiality decision, page 36.

⁷ The Slot Reservation payment (Item 1) is governed by the Slot Reservation Agreement, which provides that the payment is to be returned in the event that the agreement is cancelled by ProEnergy. Any amounts paid by Maritime Electric under the Gas Turbine Equipment Purchase and Sale Agreement (Items 2 and 3) would be subject to contractual protections. In the event of termination resulting from a default by ProEnergy, Maritime Electric would be entitled to recover the value of any Scope of Supply paid for but not provided, together with associated damages, costs and expenses, and ProEnergy would be required to remit any net amounts owing to Maritime Electric, in accordance with the terms of the Agreement.

⁸ Depending on the stage of project development, Maritime Electric may consider alternatives to cancellation that mitigate cost exposure. These may include transferring the project or associated contractual position to a third party, potentially with a negotiated settlement, or taking delivery of major equipment already procured (e.g., transformers, breakers or other long-lead items) for redeployment within the Company's system or disposition in the market. These approaches would be expected to reduce overall cost exposure to customers.

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subject to escalation due to market conditions, provided there are no changes in scope or delays attributable to Maritime Electric.

Maritime Electric considers this scenario to be unlikely given the growing regional requirement for dispatchable capacity and increasing constraints on the development of new supply.

Regulator Delay or Non-Approval

If the project does not proceed due to regulatory non-approval, or due to a regulatory delay that results in the cancellation of the Project, Items 1–3 would not be recoverable from ProEnergy.⁹ Item 4 would be transferable to a future project, while Item 5 costs, along with all carrying costs (Item 6), would not be recoverable from ProEnergy and would therefore be recoverable from customers following a prudence review.

Maritime Electric considers this scenario to be possible. However, as outlined in the Company's Response to IR-10 from Commission Staff, the Company expects that a fulsome review of the evidence will support the need for additional on-Island dispatchable capacity and the proposed solution.¹⁰

Supply Chain Disruptions

Supply chain disruptions would most likely result in delays rather than cancellation; while such delays could have implications for system reliability, they would not result in forfeited costs. If supply chain disruptions are sufficiently extensive to result in cancellation of the Project, Items 1–3 would be expected to be recoverable from ProEnergy,¹¹ Item 4 would remain transferable to a future project. Item 5 costs, along with all carrying costs (Item 6), would not be recoverable from ProEnergy and would be recoverable from customers following a prudence review.

Maritime Electric considers this scenario to be unlikely. Although supply chain disruptions are possible and may result in schedule impacts, it is unlikely that they would result in project cancellation.

Changes in System Needs

If system requirements change such that the project is no longer required, Items 1–3 would not be recoverable from ProEnergy.¹² As there would be no need for a future project, Items 4 and 5 would not be transferable, along with Item 6 costs. Accordingly, all costs would be recoverable from customers following a prudence review.

Maritime Electric considers this scenario to be unlikely given the demonstrated and growing capacity deficit on the system.

- b. Refer to Responses to IR-10, IR-11 and IR-12 from Commission Staff, filed on January 15, 2026, for the rationale for the deferral account and why it is appropriate.¹³ The deferral

⁹ Refer to footnote 8 for potential alternatives to cancellation that mitigate cost exposure.

¹⁰ Exhibit M-18.

¹¹ Refer to footnote 7 above with respect to the contractual protections governing payments to ProEnergy. Item 3, recovery may occur through the return of funds or through delivery of the associated long-lead equipment.

¹² Refer to footnote 8 above with respect to potential alternatives cancellation to limit cost exposure for Customers.

¹³ Exhibit M-18.

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account is required to allow for the timely advancement of necessary expenditures to address an urgent and growing capacity deficit, while maintaining alignment with required schedule timelines.

In the event that the deferral account is approved and the project does not proceed, all costs that are not transferrable to a future project or not recoverable from ProEnergy would be recoverable from customers following a prudence review.

- c. Refer to Response to IR-17(a).
- d. As with any contractor, there is a risk that ProEnergy withdraws from the project prior to the execution of a binding contract. Maritime Electric will not commit any payments to ProEnergy until a binding contract is executed.

Once a contract is executed, in the event of supplier withdrawal, the treatment of costs would be as outlined in Response to IR-17(a), including any initial payments made to ProEnergy (i.e., Items 1, 2 and 3) would be returned in accordance with the contractual arrangements. The extent to which other costs are at risk would depend on their nature and transferability.

The likelihood of supplier withdrawal is considered to be low. The recent approval of NB Power's RIGS project establishes ProEnergy's presence in the region, which further reduces the likelihood of withdrawal from the proposed project.

MARITIME ELECTRIC

IR-18 Provide additional information regarding Maritime Electric's long-term system planning process and the relationship between the proposed project and the outstanding Integrated System Plan.

- a. Explain Maritime Electric's plan should the Commission approve the proposed deferral account request. Include details regarding what agreements or commitments would be executed prior to final project approval, what costs would be transferred to the deferral account, who would bear the financial risks associated with those commitments, and any impacts on pricing, timelines, equipment availability, or overall project viability.
- b. Maritime Electric's Integrated System Plan was expected to be filed in Fall 2025. Explain how the Commission and customers can assess the prudence and long-term need for the proposed combustion turbine project in the absence of an updated Integrated System Plan.
- c. In Maritime Electric's March 20, 2026 correspondence, Maritime Electric indicated it was exploring future battery storage opportunities. If the proposed combustion turbines are approved, is Maritime Electric considering battery storage as a future replacement or alternative capacity resource associated with the eventual retirement of the Borden units? Provide particulars.

Response:

- a. Refer to Response to IR-17. Maritime Electric would proceed with time-sensitive commercial and development activities immediately upon approval of the proposed deferral account.

Specifically, the Company would execute the Slot Reservation Agreement with ProEnergy (Item 1) to secure manufacturing capacity and maintain the project schedule. Concurrently, Maritime Electric would begin advancing preliminary owner's work, including permitting, transmission integration design and site-specific engineering required for the project (Items 4 and 5).

Following execution of the Slot Reservation Agreement, Maritime Electric would proceed toward execution of the Gas Turbine Equipment Purchase and Sale Agreement, which would trigger the next two progress payments (Items 2 and 3). As indicated in the Company's Capacity Pricing Update Letter, filed on April 17, 2026, these three initial payments are to be paid by September 30, 2026 (i.e., within the first four months), while the subsequent payment is not due until March 30, 2028.¹⁴ Maritime Electric expects that a fulsome regulatory review can be completed within this timeframe, such that only the initial payments and associated owner's costs would be at risk if the project does not proceed.

The financial risks associated with these commitments would ultimately be borne by customers. This is appropriate as the expenditures are being incurred to maintain system reliability and ensure an adequate and secure supply of electricity for customers in the face of an increasing and near-term capacity deficit.

¹⁴ Exhibit M-28.

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As outlined in Response to IR-17, these costs must be incurred in advance of final project approval to secure manufacturing capacity and maintain the project schedule. Delaying these expenditures until all regulatory approvals are complete would significantly increase the risk of a multi-year project delay, thereby exposing customers to reliability and health and safety risks during peak periods. In addition, delays would result in increased project costs, as demand for combustion turbines remains high, manufacturing capacity is constrained and costs continue to escalate over time. In this context, the proposed deferral account reflects a prudent allocation of risk, whereby costs incurred for the benefit of customers to ensure continued reliable service are recoverable, subject to regulatory oversight.

Maritime Electric's Capacity Pricing Update Letter, filed with the Commission on April 17, 2026, provides the most current information regarding the ProEnergy proposal.¹⁵ The Company has not received any further updates from ProEnergy affecting pricing, timeline, equipment availability or project viability.

- b. Maritime Electric's previous Integrated System Plan ("ISP"), filed in 2020, identified a need for an additional 50 to 75 MW of combustion turbine capacity by 2024, based on a forecast Maritime Electric peak of 299 MW.¹⁶ Since that time, the Company's peak load has increased more rapidly than expected, resulting in the need for capacity sooner and at a higher magnitude than contemplated in the 2020 ISP. Despite a higher than forecast increase in peak load and the resulting need for more capacity, the findings of the 2020 ISP remain relevant.

In a report prepared by Synapse Energy Economics, Inc. ("Synapse") for the Commission regarding the 2020 ISP, Synapse recommended that Maritime Electric complete an On-Island Capacity Resource Study.¹⁷ In 2022, Maritime Electric engaged Sargent & Lundy LLC ("S&L") to complete a Capacity Resource Study and subsequent addendum in 2023, which were filed as part of Maritime Electric's December 2024 Application.¹⁸ These S&L documents assessed the need and prudence of adding additional on-Island capacity.

The Company submits that the 2020 ISP and evidence filed as part of the On-Island Capacity for Security of Supply Project proceeding clearly demonstrate the prudence and long-term need for the proposed combustion turbine project.

- c. Maritime Electric confirms that it continues to assess the potential capacity contributions of battery storage on PEI. As indicated in Maritime Electric's ProEnergy Update Letter, filed on March 20, 2026, the Company has engaged E3 Energy and Environmental Economics ("E3") to carry out a detailed study ("E3 Study") on the most appropriate sizing of a battery energy storage system ("BESS") for Maritime Electric.¹⁹ The E3 Study is a comprehensive Reliability and Resource Adequacy Study, which assesses Maritime

¹⁵ Exhibit M-28.

¹⁶ The 2020 ISP identifies a forecast Maritime Electric peak load of 299 MW for 2024 (Table 12, page 27). The ISP further identifies the addition of 50 to 75 MW of combustion turbine capacity in 2024 (Table 30, page 82).

¹⁷ Fagan, Bob, Shannon Liburd, and Shelly Kwok. 2022. *Prince Edward Island Resource Planning and Maritime Electric Capital Expenditures*. Synapse Energy Economics, Inc.

¹⁸ Exhibit M-1, Appendix C and Appendix D.

¹⁹ Exhibit M-26. E3 has performed resource adequacy work for Nova Scotia, New Brunswick and Newfoundland and Labrador. The Company intends to file the E3 Study in due course.

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Electric's total capacity needs and calculates the effective load carrying capability ("ELCC") contributions of various capacity resources.

The preliminary results of the E3 Study indicate that while BESS can serve as a capacity resource, its ability to contribute reliably to firm capacity diminishes as additional storage is added to the PEI system. Accordingly, while an appropriately sized BESS can make a meaningful contribution toward addressing a portion of the capacity deficit, increasing BESS capacity beyond that level results in diminishing capacity value, equivalent to derating the BESS. These findings call into question the appropriateness of larger BESS solutions as a standalone alternative to dispatchable generation and will be addressed further in Maritime Electric's response to the report prepared for the Commission by Synapse dated April 9, 2026, ("Synapse Report").²⁰

BESS is expected to form a component of Maritime Electric's future capacity additions. However, the Company must complete its assessment of the final results of the E3 Study and consider the outcome of the current Application before determining the appropriate size and timing of BESS deployment for the system. The addition of BESS could occur either prior to or following the retirement of the Borden-Carleton combustion turbines, or both, depending on system requirements at that time. More broadly, Maritime Electric expects that incremental on-Island capacity additions will be required on an ongoing basis to maintain an appropriate level of on-Island supply and to meet continued load growth, which is currently forecast to increase by approximately 10 MW per year.

²⁰ The Synapse Report is dated April 9, 2026, but was not send to Maritime Electric until May 19, 2026.

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IR-19 Provide additional information regarding Maritime Electric's procurement and due diligence process, including the extent to which Maritime Electric relied upon work completed by other utilities.

- a. In response to IR-1, Maritime Electric indicated that while it did not undertake a competitive procurement process for this project, other utilities, including NB Power and UNS Energy, selected ProEnergy through competitive processes. Explain the extent to which Maritime Electric relied upon procurement evaluations or due diligence completed by other utilities.
- b. In response to IR-4, Maritime Electric indicated that it relied upon discussions with NB Power regarding NB Power's RIGS project. Provide copies of any due diligence, assessments, evaluations, reports, or other materials prepared by or for NB Power that Maritime Electric relied upon.

Response:

- a. Maritime Electric's procurement and due diligence activities with respect to the ProEnergy proposal are described in detail in the Company's Responses to IR-1 through IR-4 (inclusive) from Commission Staff, filed on January 15, 2026.²¹ In particular, the Response to IR-4 outlines the Company's due diligence activities and evaluation of the ProEnergy opportunity.

Maritime Electric's assessment was informed in part by the procurement processes and evaluations undertaken by other utilities. This includes NB Power's RIGS project, which was procured through a competitive process. Maritime Electric was involved in extensive discussions with NB Power with regards to the RIGS project and their decision to select ProEnergy. Through this process, the Company reviewed the briefing materials prepared for NB Power's Board of Directors, which formed the basis for the recommendation to proceed with the ProEnergy solution and included consideration of technical capability, financial strength and project execution risk.

Maritime Electric also engaged with UNS Energy Corporation, which also selected ProEnergy through a competitive procurement process, but no detailed evaluation information was shared. In addition, as described in the Company's Response to IR-1 from Commission Staff, Maritime Electric compared the ProEnergy proposal against a project proposed by Newfoundland and Labrador Hydro that was subject to a competitive procurement process under a utility ownership model.²² The current \$891 million budget for that project is already approximately 78 per cent higher than Maritime Electric's proposal on a per-MW basis, and its estimated in-service date has moved to 2030, one year later than the Accelerated Capacity Solution.

Since filing previous responses to interrogatories from Commission Staff, Maritime Electric has undertaken additional due diligence through site visits to recently commissioned ProEnergy combustion turbine plants, including Salt River Project's Copper Crossing Plant (Arizona) and Oklahoma Gas & Electric's Tinker Air Force Base Plant (Oklahoma City). These site visits allowed Company personnel to observe ProEnergy equipment in

²¹ Exhibit M-18.

²² Exhibit M-18.

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operation and to engage directly with plant owners regarding project execution, logistics, equipment quality and operational performance.

Overall, feedback from the project owners was positive, with only minimal concerns identified. Projects were well executed by ProEnergy and delivered on schedule. The project owners also expressed satisfaction in ProEnergy's equipment quality and the availability of replacement parts. Overall, this due diligence provided assurance regarding ProEnergy's technical capability, product quality and operational performance, and reinforced the Company's confidence in proceeding with the ProEnergy opportunity.

These visits, in addition to Maritime Electric's earlier visit to ProEnergy's packaging facility in Sedalia, Missouri,²³ and due diligence information received from NB Power, demonstrate ProEnergy's ability to produce and deliver turbine packages in an active production environment and confirmed the reliable operation and maintainability of the installed units.

- b. Following discussions with NB Power, they sent Maritime Electric a November 8, 2024, briefing note and an October 3, 2024, briefing note, on June 1, 2025. Both briefing notes are provided in IR-19 - Attachment 1.²⁴ Redactions in the briefing note were made by NB Power.

While the two briefing notes represent the only formal documentation shared with Maritime Electric, the Company engaged in extensive discussions with NB Power regarding its procurement process and findings. Through these discussions, NB Power expressed confidence in the suitability of the ProEnergy solution for its system and for the Atlantic Canadian operating environment, and confirmed that its own due diligence, including site visits to manufacturing and operating facilities, was positive.

²³ Exhibit M-18.

²⁴ The November 8, 2024, and October 3, 2024, NB Power briefing notes were replaced with the public versions filed in New Brunswick Energy and Utilities Board Matter EL-002-2025 (NB Power's Renewables Integration and Grid Security Project), Exhibit NBP8.82, page 43-46 and page 24-26, respectively.

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IR-20 In Maritime Electric's letter to the Commission dated August 5, 2025, the Company included a copy of its letter to the Minister of Environment, Energy & Climate Action regarding the ProEnergy opportunity. In that letter, Maritime Electric referenced previous correspondence dated June 20, 2025.

Provide a copy of the June 20, 2025 correspondence from Maritime Electric to the Prince Edward Island Energy Corporation regarding the ProEnergy opportunity, including any background information, briefing materials, due diligence information, and any information received from or relating to due diligence carried out by NB Power.

Response:

The letter referenced as the June 20, 2025, correspondence in Maritime Electric's letter to the commission dated August 5, 2025, is provided as IR-20 – Attachment 1.²⁵ The letter included the November 8, 2024, briefing note from NB Power with information on the due diligence and proponent evaluation completed by NB Power.²⁶ Redactions in the briefing note were made by NB Power.

Refer to Response to IR-19(b) regarding information received from NB Power.

²⁵ The project cost of \$302 million referenced in the letter was a preliminary cost estimate. Following a more detailed cost estimate for Maritime Electric's scope of work, an updated United States Dollars to Canadian Dollars exchange rate and updated contingencies, the total estimated project cost was revised to \$334 million.

²⁶ The Redacted Internal and Confidential Briefing Notes from NB Power, which includes the November 8, 2024, NB Power briefing note, was replaced with the public version filed in New Brunswick Energy and Utilities Board Matter EL-002-2025 (NB Power's Renewables Integration and Grid Security Project), Exhibit NBP8.82, page 43-46.

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IR-21 Provide additional information regarding the ownership structure proposed by Maritime Electric and whether alternative arrangements were evaluated.

- a. Confirm whether Maritime Electric evaluated a tolling arrangement or third-party ownership model similar to NB Power's RIGS project.
- b. If such an arrangement was considered, provide particulars regarding the analysis completed, including any comparison of costs, operational flexibility, risks, financing implications, and customer impacts.
- c. Explain why Maritime Electric elected not to pursue a tolling arrangement or third-party ownership model.

Response:

- a. Maritime Electric considered a tolling agreement structure, similar to NB Power's RIGS project, but determined that it was not the preferred model for Maritime Electric's circumstances. Refer to Response to IR-21(c) for an explanation.
- b. A detailed evaluation was not completed. Refer to Response to IR-21(c) for an explanation.
- c. Maritime Electric elected not to pursue a tolling agreement or third-party arrangement for several reasons including cost, the strategic site of the Charlottetown Generating Station ("CGS") and operating and maintenance efficiencies.

A tolling agreement or third-party arrangement is not considered the least cost option for Maritime Electric's customers. In the New Brunswick Energy and Utilities Board's ("NBEUB") oral decision for the NB Power RIGS project, the NBEUB stated the following:

"the Board heard credible evidence suggesting that, depending on assumptions made, the lease/tolling model chosen by NB Power will have a net present value cost of somewhere between 82 million and 221 million in excess of an ownership model whereby NB Power would retain construction, schedule, operation, and maintenance risks. Mr. Madsen, an expert in the field of accounting and finance for utilities, depreciation expenses, financial analyses for utilities, revenue requirements and rate regulation, testified that, in his opinion, the premium would be much higher."²⁷

The strategic location of the CGS for the combustion turbines was also a consideration. The CGS site is a brownfield site owned by Maritime Electric with several benefits, which were described in detail in Section 6.2 of Maritime Electric's Supplemental Capital Budget Request for On-Island Capacity for Security of Supply Project, filed on December 18, 2024 ("December 2024 Application").²⁸ Given that the CGS site, which already contains existing generation and electrical infrastructure, is currently owned and operated by Maritime Electric, allowing a third-party to construct and own generation equipment on the site is not preferred. Maritime Electric's proposed combustion turbine project at the CGS site

²⁷ NBEUB Matter EL-002-2025, Transcript ID 854, page 32-33.

²⁸ Exhibit M-1.

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takes advantage of existing fuel storage, water treatment and electrical infrastructure on the site.

There are also several operating and maintenance efficiencies associated with Maritime Electric owning the proposed combustion turbines at the CGS site. The proposed location at the CGS site is adjacent to Maritime Electric's existing Combustion Turbine No. 3 ("CT3"). The close proximity to CT3 will result in operating and maintenance efficiencies, as Maritime Electric's existing and future combustion turbine operators can maintain all three combustion turbines proposed to be located on the same site.

It is also important to note that NB Power's current and upcoming major infrastructure projects were a factor in NB Power's decision to select a tolling agreement. The NBEUB's oral decision included the following:

"NB Power contends that the chosen delivery model: [...] shifts responsibility for planning and managing the facility from NB Power at a time when its resources are stretched and would be more adequately focused on other large projects, including the Mactaquac Life Achievement Project, the Belledune Repowering Project, the large transmission capital projects approved by the Board in Matter EL-001-2025, and the New Brunswick/Nova Scotia Interprovincial Transmission Line Project".²⁹

Maritime Electric's circumstances are different from those of NB Power. Maritime Electric is the Atlantic Canadian utility with the most recent experience developing a combustion turbine project, having successfully installed and operated CT3 at the CGS. Several of the individuals who were directly involved in the development and delivery of the CT3 project remain key members of the Company's team today. Maritime Electric does not have the same concurrent large-scale generation projects as NB Power, such as the Mactaquac Life Achievement Project or the Belledune Repowering Project, and is therefore well positioned to focus its resources on the development and execution of the proposed combustion turbine project. As such, the Company has the internal resources, expertise and operational experience required to construct, own and operate the proposed combustion turbines at the CGS site.

²⁹ NBEUB Matter EL-002-2025, Transcript ID 854, page 31-32.

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IR-22 Provide additional information regarding the risks associated with reliance on diesel-fueled combustion turbines, including fuel pricing volatility and fuel supply risks.

- a. Provide Maritime Electric's assessment of the risks associated with constructing and operating diesel-fueled combustion turbines in the current geopolitical and fuel supply environment.
- b. Provide details regarding how recent and potential future increases in distillate fuel prices have been considered in the evaluation of the proposed project.
- c. Discuss any risks associated with future fuel supply constraints or supply chain disruptions and how such risks may impact the reliability or operational feasibility of the proposed project.
- d. Indicate whether Maritime Electric has completed any sensitivity analysis regarding future diesel pricing scenarios and, if so, provide the results of such analysis.

Response:

- a. There are potential risks associated with the use of diesel-fired combustion turbines, including exposure to fuel price volatility and potential supply constraints, as is the case with other hydrocarbon fuel sources. These risks are partially mitigated by the proposed units' dual fuel capability and their expected use as peaking and backup resources, resulting in relatively low annual operating hours.

Diesel and other refined petroleum products remain widely used across the Canadian economy and are expected to continue playing a material role over the long term. The Canada Energy Regulator's *Canada's Energy Future 2026* indicates that fossil fuel demand remains relatively stable across most modeled scenarios through 2050, even as electrification increases, with ongoing demand for refined petroleum products across transportation and industrial applications.³⁰ In particular, reductions in gasoline consumption are projected to be partially offset by continued or growing demand for diesel in freight and other uses.

Accordingly, Maritime Electric expects that diesel fuel will remain readily available over the life of the proposed combustion turbines, supported by established supply chains and sustained demand across multiple sectors. In addition, the proposed combustion turbines are capable of operating on alternate fuels, including natural gas or blended hydrogen or ammonia, which provides further flexibility should fuel availability or economics evolve over time.³¹

The Government of Canada's recently released *Powering Canada Strong: A National Strategy for an Electrified Canadian Economy* acknowledges that "Natural gas-fired generation plays an important role in supporting reliable, affordable, and secure electricity systems in Canada, especially as demand quickly grows and the system becomes more complex" and that "Canada's abundant and dependably low-cost natural gas resources help enhance energy security and system resilience, while limiting exposure to global

³⁰ *Canada's Energy Future 2026 – Energy Supply and Demand Projections to 2050* - <https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2026/canada-energy-futures-2026.pdf>.

³¹ Modifications to the turbines would be required to enable them to operate using blended hydrogen or ammonia.

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supply disruptions in many regions.”³² Although there is currently no natural gas supply on PEI, compressed natural gas can be transported to PEI and stored.

While the federal strategy does not specifically reference diesel-fired generation, it emphasizes the importance of reliable, dispatchable capacity and fuel availability to maintain system resilience. These principles are directly applicable to PEI, where diesel remains the only readily available and dependable fuel source capable of supporting dispatchable generation in the near term, particularly for peaking and backup applications.

- b. Given that the proposed combustion turbines are expected to operate infrequently, Maritime Electric has not evaluated recent or potential future fuel price increases for the proposed project.

As part of Maritime Electric’s response to the Synapse report, the Company intends to incorporate diesel costs into a revised net present value analysis.

- c. Refer to Response to IR-22(a).

Future short-term diesel fuel supply constraints or supply chain disruptions are a risk and could impact the operation of the proposed project. However, this risk is mitigated through a combination of on-site storage, established regional fuel infrastructure, and multiple fuel supply pathways.

The proposed project includes the construction of two additional two-million litre diesel storage tanks, providing sufficient on-site fuel to operate the combustion turbines at full load for approximately seven days without additional deliveries. As peaking units, the combustion turbines are not expected to operate continuously at full load, which extends the effective duration of the fuel supply.

In addition, the CGS is strategically located adjacent to the Charlottetown tank farm, which contains significantly larger fuel storage capacity and supports fuel distribution across PEI. This proximity facilitates reliable resupply under both normal operating conditions and contingency scenarios.

The site is also located in close proximity to the Port of Charlottetown, which serves as the primary entry point for fuel shipments to the Island. This provides an alternate supply pathway in the event of disruptions to ground transportation, including the Confederation Bridge or ferry service, as fuel can continue to be delivered by marine shipment to the adjacent tank farm and redistributed to the CGS.

In the event of a more severe or sustained disruption to diesel fuel availability, the proposed combustion turbines are designed with dual-fuel capability, providing the ability to transition to alternative fuels. This includes the potential use of compressed or liquefied natural gas transported to the Island and supplied to the CGS, as well as the ability to convert to other fuels such as hydrogen or ammonia as supply chains mature.

³² Government of Canada. Powering Canada Strong: A National Strategy for an Electrified Canadian Economy.

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Accordingly, Maritime Electric's approach does not rely on a single fuel source or delivery method but rather incorporates multiple layers of redundancy and flexibility to ensure that dispatchable generation can continue to be supplied under a range of potential fuel supply disruption scenarios.

- d. Refer to Response to IR-22(b).



REDCATED

**IR-16 – Updated Supplemental Filing
Confidential Appendix B**

Net Present Value Inputs and Calculations

Net Present Value Analysis
ProEnergy 2 x PE6000 Combustion Turbines with Synchronous Condenser
Net Present Cost

Inputs	
Nominal Capacity (MW)	100
Fuel Type	Diesel
Useful Life (years)	50
Total Installed Cost (\$ x 1,000)	353,372
Year 1 Operation and Maintenance Cost (\$ x 1,000)	1,197
Operation and Maintenance Inflation Rate	2%
Corporate Income Tax Rate	31%
Normal Capital Cost Allowance Rate	8%
Debt Ratio	60%
Equity Ratio	40%
Debt Interest Rate	4.91%
Equity Return Rate	9.35%
Weighted Cost of Capital/NPV Rate of Return	6.69%

Project Cost (\$ x 1,000)						
Year	Amort.	O & M	Debt Interest	Equity Return	Income Taxes	Total
1	3,887	1,197	10,317	13,097	5,884	34,382
2	7,854	1,221	10,026	12,728	5,719	37,547
3	7,854	1,245	9,638	12,236	5,497	36,471
4	7,854	1,270	9,269	11,767	5,287	35,446
5	7,854	1,295	8,916	11,320	5,086	34,470
6	7,854	1,321	8,579	10,891	4,893	33,539
7	7,854	1,348	8,256	10,481	4,709	32,648
8	7,854	1,375	7,946	10,088	4,532	31,795
9	7,854	1,402	7,648	9,710	4,362	30,976
10	7,854	1,430	7,362	9,346	4,199	30,190
11	7,854	1,459	7,085	8,994	4,041	29,433
12	7,854	1,488	6,818	8,655	3,888	28,703
13	7,854	1,518	6,559	8,327	3,741	27,998
14	7,854	1,548	6,308	8,008	3,598	27,316
15	7,854	1,579	6,065	7,699	3,459	26,655
16	7,854	1,611	5,828	7,399	3,324	26,015
17	7,854	1,643	5,597	7,106	3,192	25,392
18	7,854	1,676	5,372	6,820	3,064	24,786
19	7,854	1,709	5,153	6,541	2,939	24,196
20	7,854	1,744	4,938	6,269	2,816	23,620
21	7,854	1,778	4,727	6,001	2,696	23,057
22	7,854	1,814	4,521	5,739	2,579	22,506
23	7,854	1,850	4,318	5,482	2,463	21,967
24	7,854	1,887	4,119	5,229	2,349	21,438

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25	7,854	1,925	3,923	4,980	2,237	20,919
26	7,854	1,963	3,730	4,735	2,127	20,409
27	7,854	2,003	3,539	4,493	2,019	19,907
28	7,854	2,043	3,351	4,255	1,911	19,414
29	7,854	2,084	3,166	4,019	1,806	18,927
30	7,854	2,125	2,982	3,786	1,701	18,447
31	7,854	2,168	2,800	3,555	1,597	17,974
32	7,854	2,211	2,620	3,326	1,494	17,506
33	7,854	2,255	2,442	3,100	1,393	17,044
34	7,854	2,301	2,265	2,876	1,292	16,587
35	7,854	2,347	2,090	2,653	1,192	16,134
36	7,854	2,393	1,915	2,432	1,092	15,686
37	7,854	2,441	1,742	2,212	994	15,243
38	7,854	2,490	1,570	1,994	896	14,803
39	7,854	2,540	1,399	1,777	798	14,368
40	7,854	2,591	1,229	1,561	701	13,936
41	7,854	2,643	1,060	1,346	605	13,507
42	7,854	2,695	892	1,132	509	13,081
43	7,854	2,749	724	919	413	12,659
44	7,854	2,804	557	707	318	12,239
45	7,854	2,860	390	495	223	11,822
46	7,854	2,918	224	285	128	11,408
47	7,854	2,976	59	75	34	10,997
48	7,854	3,035	-106	-135	-61	10,588
49	7,854	3,096	-271	-344	-154	10,181
50	7,854	3,158	-435	-552	-248	9,777
Total	388,709	101,225	209,224	265,614	119,334	1,084,105
NPC	116,422	24,364	103,229	131,052	58,878	433,945

**Net Present Value Analysis
Standalone Synchronous Condenser
Net Present Cost**

Inputs	
Nominal Capacity (MW)	50
Useful Life (years)	50
Total Installed Cost (\$ x 1,000)	39,000
Year 1 Operation and Maintenance Cost (\$ x 1,000)	30
Operation and Maintenance Inflation Rate	2%
Corporate Income Tax Rate	31%
Normal Capital Cost Allowance Rate	8%
Debt Ratio	60%
Equity Ratio	40%
Debt Interest Rate	4.91%
Equity Return Rate	9.35%
Weighted Cost of Capital/NPV Rate of Return	6.69%

Project Cost (\$ x 1,000)						
Year	Amort.	O & M	Debt Interest	Equity Return	Income Taxes	Total
1	429	30	1,139	1,445	649	3,692
2	867	31	1,107	1,405	631	4,040
3	867	31	1,064	1,350	607	3,919
4	867	32	1,023	1,299	583	3,804
5	867	32	984	1,249	561	3,694
6	867	33	947	1,202	540	3,589
7	867	34	911	1,157	520	3,488
8	867	34	877	1,113	500	3,392
9	867	35	844	1,072	481	3,299
10	867	36	812	1,031	463	3,210
11	867	36	782	993	446	3,124
12	867	37	752	955	429	3,041
13	867	38	724	919	413	2,960
14	867	39	696	884	397	2,883
15	867	39	669	850	382	2,807
16	867	40	643	817	367	2,734
17	867	41	618	784	352	2,662
18	867	42	593	753	338	2,592
19	867	43	569	722	324	2,524
20	867	44	545	692	311	2,458
21	867	44	522	662	298	2,393
22	867	45	499	633	285	2,329
23	867	46	477	605	272	2,266
24	867	47	455	577	259	2,205
25	867	48	433	550	247	2,144

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26	867	49	412	523	235	2,085
27	867	50	391	496	223	2,026
28	867	51	370	470	211	1,968
29	867	52	349	444	199	1,911
30	867	53	329	418	188	1,854
31	867	54	309	392	176	1,799
32	867	55	289	367	165	1,743
33	867	56	270	342	154	1,688
34	867	58	250	317	143	1,634
35	867	59	231	293	132	1,580
36	867	60	211	268	121	1,527
37	867	61	192	244	110	1,474
38	867	62	173	220	99	1,421
39	867	63	154	196	88	1,369
40	867	65	136	172	77	1,317
41	867	66	117	149	67	1,265
42	867	67	98	125	56	1,214
43	867	69	80	101	46	1,162
44	867	70	61	78	35	1,111
45	867	72	43	55	25	1,061
46	867	73	25	31	14	1,010
47	867	74	6	8	4	960
48	867	76	-12	-15	-7	909
49	867	77	-30	-38	-17	859
50	867	79	-48	-61	-27	809
Total	42,900	2,531	23,091	29,315	13,170	111,007
NPC	9,583	431	9,441	11,985	5,385	45,813

Net Present Value Analysis
ProEnergy 2 x PE6000 Combustion Turbines with Synchronous Condenser
Avoided Capacity and Ancillary Service Costs

Inputs	
ProEnergy 2 x PE6000 Combustion Turbines Nominal Avoided Capacity (MW)	100
Year 1-2 NB Power Firm Capacity Rate (\$/MW-mo)	
Year 3 NB Power Firm Capacity Rate (\$/MW-mo)	
Year 4 NB Power Firm Capacity Rate (\$/MW-mo)	
Year 5 NB Power Firm Capacity Rate (\$/MW-mo)	
Year 6 NB Power Firm Capacity Rate (\$/MW-mo)	
Year 7-50 NB Power Costs Inflation Rate	
Weighted Costs of Capital/NPV Rate of Return	6.69%

Year	NB Power Rates (\$/MW-yr)	Avoided Cost (\$ x 1,000)
	Firm Capacity	2 x PE6000 Capacity
1		
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50			
Total			6,950,449
NPC			858,238

Net Present Value Analysis
ProEnergy 2 x PE6000 Combustion Turbines with Synchronous Condenser
Summary

	Present Value (2024 \$ x 1,000)
	2 x PE6000 with Synch. Cond.
Nominal Capacity (MW)	100
Useful Life	50
Total Installed Cost (\$ x 1,000)	353,372
Annual Fixed O&M in Year 1 (\$ x 1,000)	1,197
Project Cost	
Amortization	116,422
Operating and Maintenance	24,364
Debt Interest	103,229
Equity Return	131,052
Income Taxes	58,878
Total Project Cost	433,945
Avoided Cost	
Off-Island Firm Capacity	858,238
Off-Island Load Following	0
Off-Island Spinning Reserve	0
Standalone Synchronous Condenser	45,813
Total Avoided Cost	904,051
Net Present Value	470,106
% Savings	52%



REDCATED

**IR-16 – Updated Supplemental Filing
Confidential Appendix F**

**Impact on Rate Base, Revenue Requirement
and Customer Rates Calculations**

Depreciation
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Depreciation (000s)	Reference	Annual
Depreciation Expense		
Capital Additions for 2029	A	353,372
Plant Investment for Depreciation	$C = A + B$	\$ 353,372
Depreciation Rate (Note 1)	D	2.20%
2029 Depreciation Expense (half year)	$E = C \times D$	\$ 3,887
Capital Investment		
Capital Investment	A	353,372
Less: Customer Contributions per Annual Depreciation	F	-
Total Capital Investment	$G = A + F$	\$ 353,372
Accumulated Depreciation		
Accumulated Depreciation, December 31, 2029	I	3,887
Total Change in Accumulated Depreciation	$J = H + I$	\$ 3,887
Net Book Value (NBV) - Capital Investment	$K = C - J$	\$ 349,485
Customer Contributions		
Customer Contributions per Annual Depreciation	F	\$ -
Depreciation Expense - Contributions		
Annual Contributions	F	\$ -
Depreciation Rate	L	2.20%
Amortization of Customer Contributions	$M = F \times L$	\$ -
Accumulated Depreciation, December 31, 2029	N	\$ -
Net Book Value (NBV) - Customer Contributions	$O = F - N$	\$ -
Total 2029 Depreciation Expense (Net of Contributions)	$P = E + M$	\$ 3,887
Note 1: Assumed 50 year useful life 100% / 50 Years = 2%		

Income Taxes
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Income Taxes (000s)	Reference	Annual
Capital Additions for 2029	A	353,372
Less: Contributions	B	-
CCA Deductions 2029	C	<u>14,135</u>
Ending UCC	$D = A - B - C$	\$ 339,237
Future Income Taxes		
CCA Deductions 2029	C	\$ 14,135
Accumulated Depreciation, December 31, 2029	$E =$ I - N From Page 1	<u>3,887</u>
Difference CCA/Depreciation	$F = C - E$	10,248
Future Tax Rate	G	<u>31.00%</u>
Future Income Tax Liability	$H = F \times G$	3,177
Income Tax Effects of Increased Return		
Return on Rate Base	$I = H$ from Page 3	\$ 24,186
Equity Return (grossed up)	$J =$ G from Page 3 / (1-G)	<u>20,896</u>
Taxable Income from Return on Rate Base	$K = J$	\$ 20,896
Income Tax Expense		
Taxable Income from Return on Rate Base	L	\$ 20,896
Add: Depreciation	$M = P$ from Page 1	3,887
Less: CCA	$N = 2029$ CCA	<u>(14,135)</u>
Corporate Tax Rate	$O = L + M + N$	10,648
Current Income Tax Expense	G	<u>31.00%</u>
Future Income Tax Expense	$P = O \times G$	3,301
	$Q = (-M - N) \times G$	<u>3,177</u>
Total Income Tax Expense	$R = P + Q$	\$ 6,478

2029 Rate Base & Cost of Capital
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Rate Base & Cost of Capital (000s)		Reference	
Net Book Value, Capital Investment		A = K from Page 1	\$ 349,485
Net Book Value, Contributions		B = O from Page 1	-
Future Income Taxes		C = H from Page 2	(3,177)
Projected Rate Base		D = A + B + C	\$ 346,308
Total % Increase from 2025 Actual Year End Rate Base		E = D / R	58.02%
Return on Debt		F = D X O	\$ 9,768
Return on Common Equity		G = D X P	14,418
Total Return On Rate Base		H = F + G	\$ 24,186
Weighted Average Cost of Capital ("WACC")			
Debt		I	60.0%
Common Equity		J	40.0%
Cost of Debt		K	4.23%
Cost of Common Equity		L	9.35%
2025 Average Capitalization (Total Debt plus Common Equity)		M	638,765,377
2025 Average Rate Base*		N	574,368,441
WA Cost of Debt		O = I X K X M / N	2.82%
WA Cost of Common Equity		P = J X L X M / N	4.16%
2025 WACC		Q = O + P	6.98%
2025 Year End Rate Base		R	\$ 596,902

Revenue Requirement
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

2029 Annual Project Revenue Requirement (000s)	Reference	0
Depreciation	A = P from Page 1	\$ 3,887
Return on Debt	C = F from Page 3	9,768
Return on Equity	D = G from Page 3	14,418
Income Taxes	E = R from Page 2	6,478
Estimated Annual Project Revenue Requirement	F = A + B + C + D + E	\$ 22,646
% Increase over 2025 Forecast Revenue Requirement	G = F / H	8.49%
2025 Revenue Requirement*	H	\$ 266,596
Total Change in Revenue Requirement Allocated to MECL	100% = F	\$ 22,646

* 2025 forecast revenue requirement per GRA Negotiated Settlement filed with the Commission on April 4, 2023.

Distribution Rate Impact
Estimated Impact on Rate Base, Revenue Requirement and Customer Rates

Project Rate Impact	Reference	0
Total Project Revenue Requirement	A = F from Appendix F X 1000	\$ 22,646,092
Forecast 2029 kWh Sales	B	1,724,249,644
Forecast Increase Per kWh Project Rate Impact	C = A / B	\$ 0.01313
Forecast Increase Annual Cost Benchmark Residential Customer (650 kWh per month) before tax	D = 650 kWh X C X 12 months	\$ 102.41
% Increase over 2025 Forecast Annual Cost for Rural Residential Customer	E = D / I	6.25%
% Increase over 2025 Forecast Annual Cost for Urban Residential Customer	F = D / J	6.36%
Forecast Increase Annual Cost Benchmark General Service Customer (10,000 kWh per month) before tax	G = 10,000 kWh X C X 12 months	\$ 1,575.60
% Increase over 2025 Forecast Annual Cost for General Service Customer	H = G / K	6.13%
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	I	\$ 1,639.09
2025/2026 Annual Cost Benchmark Rural Residential Customer (650 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on June 20, 2022 April 4, 2023.	J	\$1,610.89
2025/2026 Annual Cost Benchmark General Service Customer (10,000 kWh per month) excluding tax per GRA Negotiated Settlement filed with the Commission on April 4, 2023.	K	\$ 25,712.54



IR-17 – Attachment 1

Deferral Account Costs Risk Matrix

DEFERRAL ACCOUNT COSTS RISK MATRIX								
Risk	Likelihood	Deferral Account Costs						
		Item 1 Slot Reservation Payment USD \$6.24 million	Item 2 Equipment Contract Execution Payment USD \$18.72 million	Item 3 Long Lead Procurement Payment USD \$18.72 million ¹	Item 4 Owner's Costs CAD \$2 million	Item 5 Additional Costs CAD \$1 million	Item 6 Carrying Costs ²	Estimated Total Customer Cost Recovery (CAD rounded) ³
Supplier Withdrawal	Unlikely	Returned to buyer	Returned to buyer	Transferable or Salvageable	Transferable	Non-Transferable	Non-Transferable	\$1 million + carrying costs
Market Changes or Availability of Alternative Capacity	Unlikely	Forfeited	Forfeited	Transferable or Salvageable	Non-Transferable	Non-Transferable	Non-Transferable	\$37 million + carrying costs
Regulatory Delay or Non- Approval ⁴	Possible	Forfeited	Forfeited	Transferable or Salvageable	Transferable	Non-Transferable	Non-Transferable	\$35 million + carrying costs
Supply Chain Disruptions ⁵	Unlikely	Returned to buyer	Returned to buyer	Transferable or Salvageable	Transferable	Non-Transferable	Non-Transferable	\$1 million + carrying costs
Changes in System Needs	Unlikely	Forfeited	Forfeited	Transferable or Salvageable	Non-Transferable	Non-Transferable	Non-Transferable	\$37 million + carrying costs

Legend:

- Returned to buyer: costs that are refunded to Maritime Electric if the project does not proceed.
- Transferrable: costs related to items that can likely be transferred to a similar project if the project does not proceed.
- Salvageable: costs related to items that have a market value and can likely be resold.
- Forfeited: costs that are forfeit by Maritime Electric if the project does not proceed.
- Non-Transferable: costs that cannot be transferred to a similar project if the project does not proceed.

¹ The treatment of costs depends on the timing of the project cancellation and the nature of the equipment ordered.

² Carrying costs are calculated using Maritime Electric's weighted average cost of capital. The total carrying costs are dependent on the amount of time that the deferral account is in place.

³ Calculated using a Canadian Dollar to United States Dollar exchange rate of 1.38. Ranges represent lower and upper estimates based on salvage value equal to full cost and \$0, respectively.

⁴ Risk refers to regulatory delays that result in the project being cancelled. Regulatory delays are more likely to impact final project cost and schedule, rather than result in project cancellation.

⁵ Risk refers to supply chain disruptions that result in the project being cancelled. Supply chain disruptions are more likely to impact final project schedule, rather than result in project cancellation.



IR-19 – Attachment 1

NB Power Briefing Notes

NBP (UM) IR-07a Attachment - SEOC and FROC Materials REDACTED

SEOC Meeting

October 3, 2024 (Revised)

Briefing Note

DATE	October 3, 2024
PREPARED BY	Kevin Wright [REDACTED]
PURPOSE	To seek SEOC approval of the Renewables Integration and Grid Security (RIGS) Power Purchase Agreement (PPA) proponent evaluation ranking and recommendation.
ALIGNMENT TO STRATEGIC PLAN OR BUSINESS PLAN	As presented to the SEOC in April 2024. In response to unprecedented load growth and anticipated growth of variable renewables, RIGS will benefit three Transformers within our Strategic Plan. 1. Transformer #1 'Transition to a Cost-Effective, Clean and Secure Energy Supply': • Supports energy security as we phase out coal and transition to a net-zero future. • Supports our 2029 debt-to-equity goals by potentially minimizing balance sheet impacts, if certain transaction structures are reached. 2. Transformer #2 'Modernize the Grid': • Improves our capacity to support increased renewables and energy demands while assuring reliability. 3. Transformer #3 'Electrify & Grow Load': • Enables our pursuit of load growth that supports decarbonization while adapting to climate change imperatives. • Exposes new options for tapping value in-province and for neighbouring markets.
BACKGROUND	On April 17, 2024, the SEOC approved the Charter for RIGS. The RIGS charter was to identify and acquire a partner to supply ~400MW capacity and ~400MVAR voltage support to fill a projected generation shortfall in the winter 2028 heating season. Timeframes are extremely compressed, necessitating a short evaluation period. All vendors have communicated challenges in meeting project timelines. The REOI for RIGS had a deadline for proposals of August 9, 2024. Evaluation criteria were established by the project team with the advice of our external engineering consultant (HATCH) hired by NBP to advise on industry best practices relating to this procurement effort. Four proposals were submitted by the closing date. An evaluation team was established, including key members from NB Power and our consultant firm. Evaluation of proposals began upon closing, with the first consensus meeting of the evaluation team held on August 15, 2024, to rank proposals as submitted (prior to engagement with each proponent). A special SEOC meeting was held on August 19, 2024 to brief and solicit approval of the evaluation criteria established by the evaluation team and our external engineering consultant. Non-compliant bids from the REOI process were excluded from further analysis.

Information/clarification meetings were scheduled with each proponent for the week of August 19, 2024. Additionally, NBP prepared a financial model with various scenarios to compare the proposal with different proponents. NBP received proponent responses and updated the model.

In parallel with the efforts of the project team, the Business Development group has engaged a third-party consultant to further explore the true costs associated with NB Power ownership/operation of a similar facility to meet the projected capacity shortfall. This work is outside the mandate of the Project Team. NBP received unsolicited updates from the proponents under evaluation. NBP included all updates in the final recommendation to SEOC.

The Evaluation Criteria

The evaluation criteria used was the same criteria approved by the SEOC on September 4, 2024. The weighted is based on:

a. Pricing (levelized cost basis) – 30% of total

- The maximum score (30%) was awarded to the minimum price
- A reduction in points for more expensive bids based on the following formula:

$$Score = Score_{MAX} \left(2 - \frac{Price}{Price_{MIN}} \right)$$

where:

Score = The pricing score for the selected project

Score_{MAX} = 30%

Price = The price for the project being scored

Price_{MIN} = The minimum price

b. Delivery Schedule and Experience in project development, construction and Commissioning of Combustion Turbine Generators – 30% of total

- 15% for leading schedule and an additional 15% for leading delivery experience
- 5% reduction for each subsequent ranked schedule
- 2.5% reduction for each subsequent ranked delivery experience
- 2.5 % reduction for concerns with scheduling detail and accuracy

c. Experience in ownership and operation of combustion turbine generating facilities – 20% of total

- 15% base score assigned if suitable experience is demonstrated in ownership and operation of thermal power generation assets.
- Subcategories of total thermal assets, combustion turbine assets, and Canadian assets were assessed adding 5% for each leading submission and 2.5% for each second leading submission in these subcategories.

d. Configuration-20%

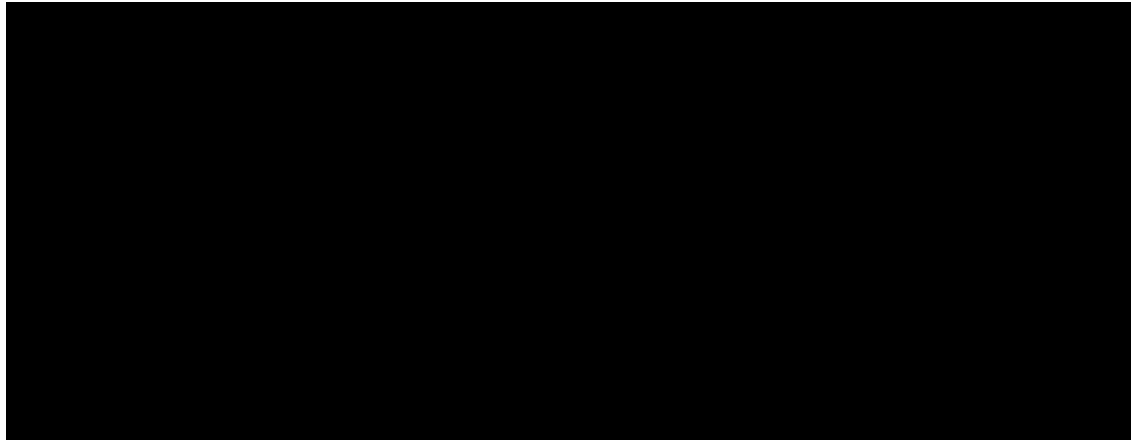
- This item includes unit configuration, size, maintenance requirements, station redundancy, startup time, and other considerations associated with the complete technical package proposed
- 20% assigned for leading capacity
- 2.5% reduction for each subsequent ranked capacity
- 2.5% reduction for areas of concern in technology maturity
- 2.5% reduction for non-compliance with minor impacts

- 5% reduction for non-compliance which could have significant impacts.

Hatch completed its analysis of the proponents using the evaluation methodology and NB Power reviewed and accepted their work.

CURRENT STATUS

The evaluation is summarized below and contained in Attachment 1.



The project team recommends proceeding with ProEnergy, the leading proponent, to further refine the scope of a PPA and develop a term sheet. A second proponent is desired to maintain a competitive environment in the next phase. TransAlta is the second-ranked proponent that we would recommend engaging with in parallel with ProEnergy. We would proceed to develop term sheets with both proponents. Concurrently, PMO and Corporate modelling will compare this in an equal criteria on a NB Power ownership model.

OPTIONS CONSIDERED

1. Power Purchase Agreement (ProEnergy/ Northland Power/ TransAlta)
 - We have received 5 EOI from proponents. After screening, we have screened out two non-confirming proposals.
 - Ownership versus partnership decision is outside of RIGS Project Team and will presented to the SEOC in a subsequent meeting.

FINANCIAL IMPACT/ BENEFITS

The enclosed HATCH report incorporates a summary of the economic evaluation that was led by NB Power's planning team.

It should be noted that the estimated impact on ratepayers is being assessed by NB Power's planning team, with analysis expected to be complete before October 18, 2024, and in advance of the SEOC decision concerning a binding term sheet, that is expected on October 24, 2024. This analysis should only be considered indicative and notional since the binding term sheets and ultimately any definitive agreements would dictate the final accounting treatments.

NB Power as a load-serving entity has a NPCC obligation to ensure enough capacity exists to meet its peak load. This CT build will ensure NB Power is compliant with this requirement.

With load following capabilities these facilities will enable a higher penetration of renewable energy to meet future energy needs

Synchronous condensers that come with these units will provide the capability to provide voltage support and reduce transmission upgrades to support an evolving inverter-based and weather driven generation sources. (Renewables)

**PROPOSED
RESOLUTION**

BE IT RESOLVED that the SEOC approves the RIGS project team recommendation to proceed to binding term sheet negotiations with ProEnergy as the preferred proponent and TransAlta as a secondary proponent and will conclude the NB Power ownership model versus partnership model in a future meeting of the SEOC.

AND BE IT FURTHER RESOLVED that the RIGS Partnership model versus the ownership model be approved by the SEOC by October 18, 2024.

AND BE IT FURTHER RESOLVED that the final binding term sheet will be brought forward to the SEOC for SEOC approval, with an anticipated date of October 25, 2024.

AND BE IT FURTHER RESOLVED that NB Power Management will seek NB Power Board of Directors approval of the Binding Term Sheet in November 2025 in order for it to become binding on the Corporation.

NEXT STEP

Upon SEOC approval of the recommended proponents, the Business Development team will proceed with negotiations with the top two ranked proponents. If for some reason, the ranking of the top two proponents switches, or if its proven we are better to own ourselves the project team will bring these facts back to the SEOC for consultation and further approvals, if necessary.

Attachments:

1. RIGS Project REOI Scoring summary
2. Hatch team credentials

RIGS Project REOI Scoring Summary

Date Updated: 2024-10-01

Criteria	Weighting				Column1
Pricing	30%	25.8%	30.0%		27.0%
Schedule and Delivery Experience	30%	27.5%	17.5%		22.5%
Ownership and Operation Experience	20%	17.5%	15.0%		20.0%
Configuration	20%	12.5%	12.5%		12.5%
Total		83.3%	75.0%		82.0%

[illegible]

Country	2019	2020	2021
United States	100	100	100
Germany	85	85	85
France	75	75	75
Italy	65	65	65
Spain	55	55	55
United Kingdom	45	45	45
Japan	35	35	35
China	25	25	25
India	15	15	15
Brazil	10	10	10
South Korea	5	5	5
Canada	3	3	3
Australia	2	2	2
South Africa	1	1	1
Argentina	0	0	0
Chile	0	0	0
Colombia	0	0	0
Costa Rica	0	0	0
Czechia	0	0	0
Denmark	0	0	0
Ecuador	0	0	0
Egypt	0	0	0
El Salvador	0	0	0
Finland	0	0	0
Ghana	0	0	0
Greece	0	0	0
Hong Kong	0	0	0
Hungary	0	0	0
Iceland	0	0	0
Ireland	0	0	0
Israel	0	0	0
Italy	0	0	0
Japan	0	0	0
Kazakhstan	0	0	0
Korea	0	0	0
Kuwait	0	0	0
Latvia	0	0	0
Lithuania	0	0	0
Malaysia	0	0	0
Mexico	0	0	0
Moldova	0	0	0
Morocco	0	0	0
Netherlands	0	0	0
New Zealand	0	0	0
Nigeria	0	0	0
North Macedonia	0	0	0
Norway	0	0	0
Oman	0	0	0
Pakistan	0	0	0
Panama	0	0	0
Paraguay	0	0	0
Peru	0	0	0
Philippines	0	0	0
Poland	0	0	0
Portugal	0	0	0
Romania	0	0	0
Russia	0	0	0
Saudi Arabia	0	0	0
Senegal	0	0	0
Singapore	0	0	0
Slovakia	0	0	0
Slovenia	0	0	0
South Korea	0	0	0
Spain	0	0	0
Sweden	0	0	0
Switzerland	0	0	0
Taiwan	0	0	0
Tanzania	0	0	0
Togo	0	0	0
Turkey	0	0	0
Ukraine	0	0	0
United Arab Emirates	0	0	0
United Kingdom	0	0	0
United States	0	0	0
Uruguay	0	0	0
Uzbekistan	0	0	0
Venezuela	0	0	0
Vietnam	0	0	0
Yemen	0	0	0
Zambia	0	0	0
Zimbabwe	0	0	0

[illegible]

A horizontal bar chart titled 'U.S. should take action to address climate change' comparing responses by age group and gender. The y-axis lists age groups: 18-29, 30-49, 50-64, 65+, and 'All adults'. The x-axis shows percentages from 0 to 100. For each age group, there are two bars: a blue bar for 'Total' and a red bar for 'Men'. The chart shows that younger age groups are more likely to believe the U.S. should take action, with 85% of the 18-29 group and 78% of men in that group believing so. The 'All adults' group shows 75% total and 68% for men.

Age Group	Total (%)	Men (%)
18-29	85	78
30-49	75	68
50-64	65	58
65+	55	48
All adults	75	68

CORE TEAM MEMBER

SENIOR MECHANICAL ENGINEER – THERMAL POWER

Education and Qualifications

BSc., Mechanical Engineering, Queen's University, 2007

Professional Affiliations

PEGNL - Professional Engineers and Geoscientists
Newfoundland and Labrador - Professional Engineer

FiPowerE - Institution of Power Engineers –
Deputy President

PEO - Professional Engineers of Ontario -
Chartered Member

Experience

17 + years

Specialties

Thermal Power Generation (Gas Turbine, Reciprocating Engine, and Steam Turbine Generators), Cogeneration, and Hybrid Power System Design

██████████ has extensive experience in power plant engineering for combustion turbine, steam turbine and reciprocating engine generator power plants employing natural gas, coal, LFO (diesel), and HFO fuels. On previous projects, he has taken on a variety of roles performing detailed engineering, commissioning, acting as Owner's Engineer, Lender's Engineer and performing condition assessments, construction monitoring, preparing commissioning work plans, and operations monitoring. This project experience has exposed ██████████ to large-scale multi-phased projects with simultaneous operating, commissioning and construction activities.

From 2016 through 2023 ██████████ has been a longstanding member of an integrated project team for the Voisey's Bay Mine Expansion working on detailed engineering, and commissioning for the new Eastern Deeps and Reid Brook combined heat and power plants. He has spent 3 years onsite supporting the project and has recently been engaged in the startup phase of the project, commissioning and operating the new generating units and high voltage switchgear and training the operations team. During this time he has developed an in depth understanding of the mine sites new and existing generating assets and power distribution system. ██████████ also has experience in other unique energy fields such as hybrid power system design, gasification for waste to energy applications and hydrogen production, coal-to-liquids, and biofuels technology.

RELEVANT PROJECT EXPERIENCE

Vale, Voisey's Bay Mine Expansion Project, Mechanical Engineer. Area Engineer for detailed engineering for two 19 MW combined heat and power (CHP) plants for the Voisey's Bay Mine Expansion (VBME) project. Package Engineer for the diesel reciprocating engine generators, and power plant major equipment. Development of power and heat demand profile based on historical climatic data, mine ventilation heating requirements, and underground mine and paste plant power demand. Provided support for emissions modelling and successful permitting of the new generating assets. Site role as a commissioning and startup engineer for the new combined heat and power plants, power distribution system, and existing power plant control system upgrades. Acted as a control room operator during commissioning phase and trained the operations team in the operation of the new generating facility.

NL Hydro, Holyrood Life Extension Condition Assessment, Mechanical Engineer. ██████████ provided condition assessment of the Holyrood thermal generating facility to assess the remaining life and sustaining capital requirements of the power plant boilers, steam turbine generators, balance of plant systems and facility assets. Provided local support for the multidisciplinary team of Hatch subject matter experts by performing site visits and data collection. Completed assessment of black start diesel generator facilities. The study assessed the required refurbishment works and investment for future operation of the generating station to provide backup power generation and synchronous condensing services.

Emirates Global Aluminium, Gas Turbine Combine Cycle and Simple Cycle Power Plant, Mechanical Engineer. ██████████ completed a design review, project completion review and operations monitoring for the gas turbine combined cycle and simple cycle power plant development for the Emirates Aluminum smelter phase 1 and phase 2 projects as well as construction monitoring for the phase 2 power plant expansion and the final expansion of the facility to integrate the power plant with an alumina refinery for process steam and power supply. The initial phase 1 and 2 projects included the development of 4 on 2, and 3 on 2 combined cycle power plants with 2 simple cycle gas turbine generators and the final phase of the project involved the addition of a 10th combustion turbine generator and HRSG and the conversion of the simple cycle combustion turbines to combined cycle. Phase 1 of the project reached 2,000 MW in generating capacity and Phase 2 and the alumina refinery integration project expanded the power plant to greater than 3,000 MW in generating capacity.

Prime Energia, Chile: Condition Assessment of a 72 MW Simple Cycle combustion turbine power plant. [REDACTED] completed a condition assessment of a simple cycle combustion turbine power plant operating on light fuel oil. The condition assessment included a review of mechanical inspection, borescope reports, and controls inspection reports by OEM technicians as well as balance of plant equipment, the electrical interconnection and environmental permitting.

Confidential Client, Condition Assessment of Thermal Power Assets. [REDACTED] performed a condition assessment of a portfolio of power plant assets which included a 60 MW HFO steam power plant, 80 MW pulverized coal fired power plant, simple cycle gas turbine generating units, and a 110 MW repowered gas turbine combined cycle power plant (gas turbines with HRSGs installed to replace original oil-fired boilers, repowering the original STGs). The project included site visit assessments of each facility and maintenance history review and the development of a sustaining capital plan and operating cost estimates, and remaining life estimate for each power plant.

Enercal, New Caledonia, Prefeasibility study for the refurbishment and Expansion of a 55 MW HFO reciprocating engine power plant. Performed a site visit to assess the condition of the power plant and balance of plant equipment and collect data for the PFS study. Acted as technical lead on the project and prepared layout drawings, PFDs and CAPEX/OPEX estimates.

Glencore, Quebec, Canada: Sustaining CAPEX plan for remote LFO fired reciprocating engine-based power generation assets. [REDACTED] visited the project site and undertook a visual assessment of the generating units and reviewed the maintenance plan and history with operating personnel for close to 50 different medium and high-speed primary and back up gensets critical to operations. Reviewed manufacturer maintenance schedules and developed a sustaining capital investment plan based on the recommended minor and major overhaul schedules and hours accrued annually by each generating unit.

OPG, Darlington Nuclear, Auxiliary Steam Plant, Mechanical Engineer. Detailed engineering of a new auxiliary steam plant for a 3,512 MW nuclear power plant in Ontario, Canada. Lead the development of the Piping and Instrumentation Drawings (P&IDs), Process Flow Diagrams (PFDs), and equipment lists and acted as a package engineer and engineering team member for the balance of plant design. Provided construction and commissioning support. The plant design included a new demineralized water plant in addition to a tie in to the existing power plant demineralized water production.

Kinross, Tasiast Gold Mine Combined Cycle Power Plant. [REDACTED] was a member of the engineering team for detailed engineering of a 150 MW combined cycle gas turbine power plant. The project considered light fuel oil and future conversion to natural gas fuel options and initially explored EPC, IPP, BOO, and BOOT project execution structures, eventually selecting an EPCM structure due to the location of the project and market feedback. [REDACTED] supported mechanical equipment list development and develop equipment specification packages for the engineering phase of the power plant area of the project.

Barrick, USA: Feasibility study for a solar/ diesel hybrid power plant. [REDACTED] developed diesel power plant configuration and specification and procurement package for diesel generators. System design and engineering considering diesel generator operating constraints, local EPA emissions regulations, and redundancy required to provide reliable power supply under both hybrid and diesel only operation.

Xstrata Raglan, Quebec Canada: Scoping study for a wind/diesel hybrid power plant. Study of the integration of a wind farm with an existing 12 MW LFO fired combined heat and power plant and operation modelling considering diesel engine operating constraints. Evaluation of diesel fuel savings due to offset LFO power generation while considering backup boiler firing due to reduced thermal output from the heat recovery system.

Kinross Gold Corporation., Kupol, Russia: Project execution for a combined heat and power plant for a remote gold mine. [REDACTED] was package engineer for heat recovery system for diesel generators for district heating. Developed equipment specifications, datasheets, procurement documents, and assisted with P&ID development. Acted as project mechanical equipment list manager and developed line list and valve list piping engineering documents.

HMI Nickel Inc., El Estor, Guatemala: Engineering for coal fired power plant and refurbishment of existing HFO fired power plant. [REDACTED] was a key member of the project team for a feasibility study for the construction of two new coal fired CFB boilers, and two 75 MW steam turbines for the refurbishment of the Exmibal nickel mine. He managed mechanical equipment list, and developed specifications and bid reviews for the steam turbine generators and balance of plant equipment. [REDACTED] reviewed coal conveyor sizing and completed a study of coal storage options. He sized circular stacker reclaimers, pipe conveyors and a storage dome. [REDACTED] assisted with power plant and fuel stockyard layout development and capital and operating cost estimating. He also developed piping & instrumentation diagrams (P&ID's) and process flow diagrams.

CORE TEAM MEMBER**MECHANICAL ENGINEERING EIT – THERMAL POWER****Education and Qualifications**

BSc., Mechanical Engineering, University of Toronto, 2023.

Minor in Business and specializations in Energy & Manufacturing.

Experience

3 Years

■■■■■ received her BSc in Mechanical Engineering from the University of Toronto with a minor in business and specializations in energy and manufacturing. Throughout her undergrad she gained valuable work experience in project management, construction, manufacturing, and cost estimation. She completed a 16-month internship at Hatch on the Jansen Potash Project, gaining exposure to all stages of the project lifecycle working both in the office and as a field engineer on site contributing to the engineering and construction management of both surface and underground scopes of work. Since returning to Hatch full time, ■■■■■ worked as an isometric controller on a gold processing facility before joining the power business unit. Within power where she has worked as a package engineer on both simple cycle and geothermal detailed plant designs, decarbonization studies, due diligence reviews and technology evaluation and selection.

PROJECT EXPERIENCE

FEED Study Simple Cycle Power Plant, Confidential Client. Mechanical engineering EIT on a simple cycle thermal power plant project in New Brunswick. Responsible for equipment sizing calculations, specification packages, procurement evaluation, mechanical layout, deliverable coordination, CAPEX/OPEX estimation and schedule execution. Coordinated a detailed combustion turbine technology evaluation amongst proponents, involving a detailed report and technology recommendation.

Geothermal Power Plant, Confidential Client. Package Engineer on a geothermal power plant project in California responsible for various pieces of equipment. Work involves gathering requirements, developing technical documentation, maintaining project timelines, and evaluating vendor bids and awards.

Thermal Energy Storage Study, Confidential Client. Mechanical engineering EIT on a thermal energy storage analysis for a power plant project in Guinea, Africa. Study involved sizing a photovoltaic system to generate electricity and produce heat inside a storage material which could be utilized to fully decarbonize the boilers and calciner on site. Analysis involved detailed calculations and analysis, CAPEX/OPEX estimates, final report and presentation of technology to the client.

Freeport MMR Indonesia. Mechanical engineering EIT on Freeport MMR Gold Processing Facility. Responsible for the coordination of a team of engineers, designers, and checkers to deliver over 7000 Piping Isometrics for fabrication and spooling to support construction on site. Coordination involved the generation of a master deliverable schedule, analysis to determine impact of held vendor information, progress tracking and weekly client forecast deliverables. Supported the piping team outside of my role with hydraulic calculations using Fathom to size various pumps and valves for vendor procurement, PNID generation & markups and layout analysis.

Jansen Potash Mine, Mechanical/Field Engineer. Mechanical engineering intern on the Jansen Potash Project located in Saskatchewan, Canada. Responsible for alternative design analysis, technical energy studies and was a package engineer on various equipment packages. Traveled to Saskatchewan on a 14/7 turnaround rotation to work on the Jansen Potash Mine. Responsible for the coordination and engineering of construction execution and technical deliverables for various scopes of work on surface and underground. Worked directly with various contractors to develop engineered scopes of work, execution plans, work schedules, facilitate contractor bids and scope of work contractor awards. Conducted contractor site fabrication inspections to identify quality flaws, compliance to requirements and progress relative to project execution plan and schedule.

CORE TEAM MEMBER

THERMAL TECHNOLOGIES SME – THERMAL POWER

Education & Qualifications

BScE, 2013

MAsc, Aerospace Engineering, 2015

Experience

9 years

Specialties

Combustion systems, gas turbines, thermal power, modelling

████ is a Thermal Power Specialist in the Power Business Unit. He has experience in gas turbine combustion and performance, as well as in the development of powerhouse models for steam and waste heat recovery applications. █████ has developed detailed knowledge of techniques for reducing emissions from gas turbines, reciprocating engines, and steam boilers. Recent projects include research on leading and emerging technologies for emission reduction from combustion equipment, feasibility study for reducing NOx emissions from natural gas boilers at a mine in Saskatchewan, and development of a powerhouse model for an Alumina refinery in Brazil. Prior to employment at Hatch █████ worked as a performance computing specialist at Siemens Aeroderivative Gas Turbines division where he developed performance modelling software for stationary gas turbines. █████ also conducted research in gas turbine combustion dynamics with a focus on emissions performance in the course of completing his MAsc at the University of Toronto.

RELEVANT PROJECT EXPERIENCE

Scoping Study for Zero Carbon Emission On-Site Power Generation, Confidential Client – Hatch developed a conceptual study of natural gas combined cycle power generation with post-combustion carbon-capture (NGCC-CCS) to meet the on-site power demands of a mine operating in western Canada. █████ served as the study lead for this work. Key evaluations completed as part of this study was developing the sizing and configuration of amine-CCS equipment suitable for the size of NGCC process, evaluating the preferred configuration of combined cycle equipment, and designing the integration of heat demand and the cogen process.

Blue Hydrogen to Power Conceptual Development, Confidential Client - Hatch is supporting the development of a Small Modular Clean Hydrogen (SMCH) solution for the production of low carbon 'blue hydrogen' from natural gas. As part of the project, █████ completed a detailed review of the key technical and performance aspects of utilizing hydrogen and hydrogen/natural gas mixtures (from 35% to 100% hydrogen) in gas turbines, and as feedstock to existing conventional natural gas fueled turbine and gas engine configurations.

Power Generation System Digital Twin - Hatch developed a digital twin of the power generation and distribution system for ExxonMobil's Hibernia platform. As the Gas Turbine specialist for this project, █████ was responsible for developing the models and interface of gas turbine performance to be integrated into the tool and to develop calibrations for the tool to accurately represent expected fuel consumption and greenhouse gas emissions.

Boiler Coal to Biomass conversion, Confidential Client – Hatch was contracted to evaluate the feasibility of converting an existing pulverized coal boiler to a steam-exploded biomass feedstock. This study included the evaluation of existing steam generation equipment to determine a preferred upgrade strategy to meet NOx emissions standards

- █████ served as the project manager and was responsible for assessing impact of conversion on the boiler performance.
- Completed site visit to observe installation of current equipment, evaluate existing P&IDs
- Concept development for alternatives
- Estimate installation requirements and schedule

SEOC Meeting

November 12, 2024

Briefing Note

DATE	November 8, 2024
PREPARED BY	Kevin Wright [REDACTED]
PURPOSE	To seek Strategic EOC approval of the Renewables Integration and Grid Security (RIGS) Power Purchase Agreement (PPA) proponent selection and direction to proceed to finalize a definitive agreement with the selected proponent.
ALIGNMENT TO STRATEGIC PLAN OR BUSINESS PLAN	As presented to the Strategic EOC in April 2024, in response to unprecedented load growth and anticipated growth of variable renewables, RIGS will benefit three Transformers within our Strategic Plan • Transformer #1 <i>Transition to a Cost-effective, Clean and Secure Energy Supply</i> – supports energy security as we phase out coal and transition to a net-zero future – supports our 2029 debt-to-equity goals by potentially minimizing balance sheet impacts, if certain transaction structures are reached • Transformer #2 <i>Modernize the Grid</i> – improves our capacity to support increased renewables and energy demands while assuring reliability • Transformer #3 <i>Electrify and Grow Load</i> – enables our pursuit of load growth that supports decarbonization while adapting to climate change imperatives – exposes new options for tapping value in-province and for neighbouring markets
BACKGROUND	On April 17, 2024, the Strategic EOC approved the Charter for RIGS. The RIGS charter was to identify and acquire a partner to supply ~400MW capacity and ~400MVAR voltage support to fill a projected generation shortfall in the winter 2028 heating season. Timeframes are extremely compressed, necessitating a short evaluation period. All vendors have communicated challenges in meeting project timelines. Five proposals were submitted by four proponents prior to the closing date. An evaluation team was established, including key members from NB Power and our consultant firm. Evaluation of proposals began upon closing, with the first consensus meeting of the evaluation team held on August 15, 2024 to rank proposals as submitted (prior to engagement with each proponent). In parallel with the efforts of the project team, the potential of an NB Power ownership option was also considered. In recognition of the significant demand for the necessary material and equipment, NB Power would be unable to meet the required schedule on its own causing a significant risk to energy security. NB Power has a limited strategic advantage in natural gas assets and the proposed technology. NB Power has demonstrated suitable operation of thermal assets, but only operates a relatively small number of varied thermal assets and does not have any units matching the configuration/type of the RIGS project. Many of the proponents have fleets of like units that will enable operational

efficiencies and provides them a distinct advantage in the operation and maintenance of the units.

In addition, NB Power has several large projects to plan for and execute between now and 2027 (e.g. Mactaquac Life Achievement project, Belledune fuel conversion, Transmission build and potential partnerships with Point Lepreau Nuclear Generating Station (PLNGS)) and limited capacity to assume additional large-scale projects.

These competing priorities are anticipated to prove challenging, leading to an unacceptable schedule risk tolerance in meeting capacity requirements for customers. It is recognized that pursuing a Power Purchase Agreement arrangement for this project may result in paying a financial premium to reduce the schedule risk. Based on this assessment, the ownership option is not recommended for this project.

CURRENT STATUS

On October 3, the Strategic EOC approved the RIGS evaluation team's recommendation to proceed with negotiations with ProEnergy and TransAlta while confirming whether an ownership option was viable.

EVALUATION CRITERIA

The evaluation criteria used was the same criteria approved by the Strategic EOC on September 4 and used to compare the potential proponents from the Request for Expression of interest proposal. One bid was removed from consideration on October 3.

The included analysis compares the Partnership model with ProEnergy and TransAlta. The criteria weighting is based on

- a. pricing (levelized cost basis) – 30% of total
 - the maximum score (30%) was awarded to the minimum price
 - a reduction in points for more expensive bids based on the following formula

$$Score = Score_{MAX} \left(2 - \frac{Price}{Price_{MIN}} \right)$$

where

Score = The pricing score for the project being scored

Score_{MAX} = 30%

Price = The price for the project being scored

Price_{MIN} = The minimum price of all projects

- b. delivery schedule and experience in project development, construction and commissioning of combustion turbine generators – 30% of total
 - 15% for leading schedule and an additional 15% for leading delivery experience
 - 5% reduction for each subsequent ranked schedule
 - 2.5% reduction for each subsequent ranked delivery experience
 - 2.5 % reduction for concerns with scheduling detail and accuracy
- c. experience in ownership and operation of combustion turbine generating facilities – 20% of total
 - 15% base score assigned if suitable experience is demonstrated in ownership and operation of thermal power generation assets
 - subcategories of total thermal assets, combustion turbine assets, and Canadian assets were assessed adding 5% for each leading submission and 2.5% for each second leading submission in these subcategories

SCORING

As negotiations have progressed, confidence in the ProEnergy schedule is achievable assuming Environmental Impact Assessment and other items can be completed in a reasonable time frame. Confidence in Trans Altas ability to meet requirements has diminished including their ability to meet the schedule.

While discussions with ProEnergy evolve we have seen an improvement to pricing in the variable component and have established language around Liquidated damages relative to Commercial Operation Date (COD).

It has been become evident that ProEnergy is the only proponent that can meet schedule but also stand behind their dates with Liquidated Damages. The ranking using the approved evaluation criteria would see ProEnergy selected as the lead proponent.

KEY TERMS

Category	Key Term	Summary
Dates	Targeted COD	used in the determination of Delay Damages
	Guaranteed COD	(days from Target) used to determine Decreased Capacity Damages (TBD) and Early Termination Damages (if contract is terminated)
	Term	25 Years
Price	Capacity Price	USD/kW-month +\$ for increased Liquid Fuel storage from 60 hours to 10 days - escalating at % p.a.
	Capacity Payment	Capacity Price x Capacity x Availability Adjustment
	Availability Adjustment	if Availability Percentage is less than capacity price is reduced by for each percentage below
	Variable Payments	\$ per hour for each Unit on synchronous condenser mode \$ per fired hour for each Unit generating using Natural Gas \$ per fired hour for each Unit generating using Liquid Fuel - variable prices escalating at p.a.
Outages	Scheduled Outages	scheduled 90 days in advance of Summer and Winter seasons
	Maintenance Outages	scheduled by 7:00 AM (AST) on the Business Day prior annual limits on maintenance hours are under negotiation

- a risk on schedule exists that the Environmental Impact Assessment timeline may jeopardize Commercial Operation Date on the project
 - this risk would be present regardless of the proponent
 - the risk has been identified and socialized with the leading proponent and the proponent is willing to work with NB Power to minimize this risk on a shared risk approach or a back stop while ordering long lead items

- additional cost factors that are not currently considered in the Power Purchase Agreement include the transmission interconnection cost, pipeline construction cost and the incremental costs being incurred to facilitate site preparation
 - as an offset to cost, NB Power is currently determining the amount of liquid fuel storage that is required on site
 - while all cost forecasts to date have included an assumption of 10 days of storage, the impact of reducing to a proposed 60 hours of storage will save NB Power [REDACTED] per year

Other financial considerations

- the rate impact in the first full year of operation is 4.98% (\$109 million)
- the revenue requirement excluding fuel over the 25 years is [REDACTED]
- the accounting treatment to be resolved in coming weeks but impact will be to the balance sheet
 - impact will be in the range of \$0 - [REDACTED]
- a \$10 million USD increase in CAPEX related to deviating soil conditions or added interconnect costs, you can consider approximately a [REDACTED] kW-month USD increase in the toll

**PROPOSED
RESOLUTION**

BE IT RESOLVED that the Strategic EOC approves

- 1) the pursuit of partnership option as the most viable to ensure capacity requirements can be met by November 2027
- 2) the pursuit of the RIGS partnership model with ProEnergy and the terms outlined in this briefing note

NEXT STEP

Assuming approval, the Business Development team will proceed with negotiations with ProEnergy to finalize a definitive tolling agreement and a property lease agreement.

Board of Directors approval of the partnership option and the terms outlined in this briefing note is scheduled for November 19, 2024.

When completing a final draft agreement, the business development team will come back to the Strategic EOC for approval to execute these agreements.

ATTACHMENTS

Appendix A contains the Energy Security Corporate Risk
Appendix B contains the Summary of terms of Tolling Agreement



IR-20 – Attachment 1

**Letter to PEIEC
June 20, 2025**

All our energy.
All the time.

June 20, 2025



Via email: gordonmacfadyen@gov.pe.ca

Gordon MacFadyen
Chief Executive Officer
PEI Energy Corporation
PO Box 2000
Charlottetown PE C1A 7N8

On-Island Capacity for Security of Supply Project

Dear Gordon:

As part of the On-Island Capacity for Security of Supply project, we are providing the following information to support an opportunity to work collaboratively with NB Power to order two 50 megawatt ("MW") combustion turbines ("CTs") from the same supplier, ProEnergy, and to offer transparency regarding recent developments.

Attached are two redacted internal and confidential briefing notes from NB Power outlining their recommendation to enter negotiations with ProEnergy following their Request for Expression of Interest for a 400 MW CT plant. NB Power emphasized the urgency of securing adequate generation capacity and identified ProEnergy as the only proponent capable of meeting their required timelines. Their evaluation ranked ProEnergy's proposal highest among the top three submissions.

Also attached are:

- ProEnergy's technical and product data sheets; and
- A briefing note outlining Maritime Electric's opportunity to collaborate with NB Power on constructing 50 MW CTs on PEI.

These documents demonstrate the thorough due diligence conducted to date by NB Power and their consultants. While we acknowledge and appreciate the depth of their analysis, we are committed to conducting our own independent due diligence should we proceed with this opportunity. In terms of cost, Sargent & Lundy's ("S&L's") 2024 estimate for one 50 MW CT, which we provided in the application, was CDN \$156 million; so two 50 MW CTs would be CDN \$312 million. S&L's updated April 2025 estimate for two 50 MW CTs has increased to CDN \$384 million. In comparison, ProEnergy's quote for the same capacity (i.e., 100 MW) is CDN \$302 million, representing a potential savings of approximately \$82 million (20%). These estimates were converted from USD using an exchange rate of 1.36 and include fuel tanks and contingencies. Given the increasing demand for generation and the upward pricing trend, we believe that timely action is critical to securing cost-effective generation capacity.

Please let me know if you require any additional information or would like to discuss this further.

Yours truly,

MARITIME ELECTRIC

Enrique Riveroll
Vice-President, Sustainability &
Customer Operations

EAR09
Enclosure



"Private and Confidential"

Opportunity to Participate with NB Power on Generation Project

Potential Opportunity to Collaborate with NB Power for Generation Project on PEI

Overview of the Project

NB Power is initiating a generation project in collaboration with ProEnergy to construct a combustion turbine (“CT”) plant. ProEnergy was selected by NB Power as the successful vendor following a request for expression of interest process which evaluated five proposals. The plant will feature eight 50 MW CTs, resulting in a total capacity of 400 MW. The CTs are dual-fuel (diesel and natural gas) and equipped with synchronous condensing capabilities, which meet Maritime Electric's requirements.

Participation Opportunity

Maritime Electric has a promising opportunity to contract with the same vendor to install two 50 MW CTs at the Charlottetown Generating Station, totaling 100 MW. During this period of high demand for CTs, ProEnergy typically would not consider projects with fewer than four CTs (i.e., 200 MW). However, the vendor is willing to consider this project as an extension of their nearby work.

Advantages of Partnership

- **Reduced Costs:** The proposed CTs are refurbished units, which offer reduced costs compared to typical CT plants. Maritime Electric operates its fleet of CTs sparingly; it is common for some utilities to operate their CTs more in one year than Maritime Electric operates its CTs over twenty years. Refurbished units provide excellent value for Maritime Electric's intended operation.
- **Installation Efficiencies:** Executing this joint project will result in significant installation efficiencies, including shared contractors, mobilization and common engineering shared across all ten units. ProEnergy has developed a streamlined design for a two 50 MW CT package, produced at a facility dedicated to fabricating units identical to Maritime Electric's CT3 in Charlottetown. This allows for streamlined production and the two-unit package allows for shared equipment, such as the control house and motor control centres, further increasing cost efficiencies.
- **Accelerated Timeline:** The expected in-service date for the project is 2028, which is significantly faster than the typical supplier's procurement paths, that have timelines beyond 2030.
- **Improved Operating and Maintenance Resources:** ProEnergy will operate and maintain the units in New Brunswick and intends to set up a service centre in that province to support the NB Power plant. Installing the same units as NB Power will provide Maritime Electric with access to local original equipment manufacturer operating and maintenance resources.

Financial Commitment

To seize this opportunity, a commitment deposit of approximately \$30 million is required in June 2025. This upfront commitment, referred to as a Limited Notice to Proceed (“LNTP”) deposit, allows ProEnergy to secure long lead items and begin engineering for the project. The LNTP includes initial engineering expenses as well as downpayments for:

- generators;
- generator step-up transformers;
- clutches (to allow synchronous condensing operation);
- breakers;
- switchgear;
- station service equipment including motor control centres;
- continuous emission monitoring equipment; and
- water treatment equipment.

Approximately six months after an LNTP commitment, full contract execution will be required, with additional financial commitments expected at that time. Costs incurred on items such as site preparation and engineering would not be refundable from the LNTP deposit. However, the remaining items (e.g., deposits on long-lead equipment listed above) would retain value even if Maritime Electric opted to not proceed with the project. In that scenario, Maritime Electric could either pay the remaining cost and install the equipment or sell it to other interested parties. There may also be an option for the vendor to buy back the equipment at a reduced cost.

Next Steps

To date, Maritime Electric has had discussions with NB Power and ProEnergy, who have visited the Charlottetown Plant site and provided a quote. Maritime Electric is requesting approval to enter detailed negotiations with ProEnergy to define project details and commit to the approximately \$30 million LNTP deposit.

Impact on Generation Project Application to IRAC

Should Maritime Electric proceed with this opportunity, the two CTs would represent 100 MW of the original 150 MW of generation capacity requested in the application. The Company must still pursue the remaining 50 MW, but further upfront engineering is required to determine the source of that capacity. The completion of 100 MW of generation by 2028 would mitigate significant risk on Maritime Electric’s capacity deficit and allow additional time for engineering and approvals of the remaining 50 MW.

Conclusion

This project presents a compelling opportunity to install the critical generation capacity at a lower cost and within an accelerated timeline. The strategic location and shared construction resources further augment the potential benefits of Maritime Electric’s participation. The required LNTP deposit, while substantial, is justified by the expected advantages and limited risk of the commitment. We recommend thorough evaluation and prompt decision-making to capitalize on this unique opportunity.



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Redacted Internal and Confidential Briefing Notes from NB Power

Briefing Note

DATE	November 8, 2024
PREPARED BY	Kevin Wright [REDACTED]
PURPOSE	To seek Strategic EOC approval of the Renewables Integration and Grid Security (RIGS) Power Purchase Agreement (PPA) proponent selection and direction to proceed to finalize a definitive agreement with the selected proponent.
ALIGNMENT TO STRATEGIC PLAN OR BUSINESS PLAN	As presented to the Strategic EOC in April 2024, in response to unprecedented load growth and anticipated growth of variable renewables, RIGS will benefit three Transformers within our Strategic Plan • Transformer #1 <i>Transition to a Cost-effective, Clean and Secure Energy Supply</i> – supports energy security as we phase out coal and transition to a net-zero future – supports our 2029 debt-to-equity goals by potentially minimizing balance sheet impacts, if certain transaction structures are reached • Transformer #2 <i>Modernize the Grid</i> – improves our capacity to support increased renewables and energy demands while assuring reliability • Transformer #3 <i>Electrify and Grow Load</i> – enables our pursuit of load growth that supports decarbonization while adapting to climate change imperatives – exposes new options for tapping value in-province and for neighbouring markets
BACKGROUND	On April 17, 2024, the Strategic EOC approved the Charter for RIGS. The RIGS charter was to identify and acquire a partner to supply ~400MW capacity and ~400MVAR voltage support to fill a projected generation shortfall in the winter 2028 heating season. Timeframes are extremely compressed, necessitating a short evaluation period. All vendors have communicated challenges in meeting project timelines. Five proposals were submitted by four proponents prior to the closing date. An evaluation team was established, including key members from NB Power and our consultant firm. Evaluation of proposals began upon closing, with the first consensus meeting of the evaluation team held on August 15, 2024 to rank proposals as submitted (prior to engagement with each proponent). In parallel with the efforts of the project team, the potential of an NB Power ownership option was also considered. In recognition of the significant demand for the necessary material and equipment, NB Power would be unable to meet the required schedule on its own causing a significant risk to energy security. NB Power has a limited strategic advantage in natural gas assets and the proposed technology. NB Power has demonstrated suitable operation of thermal assets, but only operates a relatively small number of varied thermal assets and does not have any units matching the configuration/type of the RIGS project. Many of the proponents have fleets of like units that will enable operational

efficiencies and provides them a distinct advantage in the operation and maintenance of the units.

In addition, NB Power has several large projects to plan for and execute between now and 2027 (e.g. Mactaquac Life Achievement project, Belledune fuel conversion, Transmission build and potential partnerships with Point Lepreau Nuclear Generating Station (PLNGS)) and limited capacity to assume additional large-scale projects.

These competing priorities are anticipated to prove challenging, leading to an unacceptable schedule risk tolerance in meeting capacity requirements for customers. It is recognized that pursuing a Power Purchase Agreement arrangement for this project may result in paying a financial premium to reduce the schedule risk. Based on this assessment, the ownership option is not recommended for this project.

CURRENT STATUS

On October 3, the Strategic EOC approved the RIGS evaluation team's recommendation to proceed with negotiations with ProEnergy and TransAlta while confirming whether an ownership option was viable.

EVALUATION CRITERIA

The evaluation criteria used was the same criteria approved by the Strategic EOC on September 4 and used to compare the potential proponents from the Request for Expression of interest proposal. One bid was removed from consideration on October 3.

The included analysis compares the Partnership model with ProEnergy and TransAlta. The criteria weighting is based on

a. pricing (levelized cost basis) – 30% of total

- the maximum score (30%) was awarded to the minimum price
- a reduction in points for more expensive bids based on the following formula

$$Score = Score_{MAX} \left(2 - \frac{Price}{Price_{MIN}} \right)$$

where

Score = The pricing score for the project being scored

Score_{MAX} = 30%

Price = The price for the project being scored

Price_{MIN} = The minimum price of all projects

b. delivery schedule and experience in project development, construction and commissioning of combustion turbine generators – 30% of total

- 15% for leading schedule and an additional 15% for leading delivery experience
- 5% reduction for each subsequent ranked schedule
- 2.5% reduction for each subsequent ranked delivery experience
- 2.5 % reduction for concerns with scheduling detail and accuracy

c. experience in ownership and operation of combustion turbine generating facilities – 20% of total

- 15% base score assigned if suitable experience is demonstrated in ownership and operation of thermal power generation assets
- subcategories of total thermal assets, combustion turbine assets, and Canadian assets were assessed adding 5% for each leading submission and 2.5% for each second leading submission in these subcategories

SCORING

As negotiations have progressed, confidence in the ProEnergy schedule is achievable assuming Environmental Impact Assessment and other items can be completed in a reasonable time frame. Confidence in Trans Altas ability to meet requirements has diminished including their ability to meet the schedule.

While discussions with ProEnergy evolve we have seen an improvement to pricing in the variable component and have established language around Liquidated damages relative to Commercial Operation Date (COD).

It has been become evident that ProEnergy is the only proponent that can meet schedule but also stand behind their dates with Liquidated Damages. The ranking using the approved evaluation criteria would see ProEnergy selected as the lead proponent.

KEY TERMS

Category	Key Term	Summary
Dates	Targeted COD	used in the determination of Delay Damages
	Guaranteed COD	(days from Target) used to determine Decreased Capacity Damages (TBD) and Early Termination Damages (if contract is terminated)
	Term	25 Years
Price	Capacity Price	USD/kW-month +\$ for increased Liquid Fuel storage from 60 hours to 10 days - escalating at % p.a.
	Capacity Payment	Capacity Price x Capacity x Availability Adjustment
	Availability Adjustment	if Availability Percentage is less than capacity price is reduced by for each percentage below
	Variable Payments	\$ per hour for each Unit on synchronous condenser mode \$ per fired hour for each Unit generating using Natural Gas \$ per fired hour for each Unit generating using Liquid Fuel - variable prices escalating at p.a.
Outages	Scheduled Outages	scheduled 90 days in advance of Summer and Winter seasons
	Maintenance Outages	scheduled by 7:00 AM (AST) on the Business Day prior annual limits on maintenance hours are under negotiation

- a risk on schedule exists that the Environmental Impact Assessment timeline may jeopardize Commercial Operation Date on the project
 - this risk would be present regardless of the proponent
 - the risk has been identified and socialized with the leading proponent and the proponent is willing to work with NB Power to minimize this risk on a shared risk approach or a back stop while ordering long lead items

- additional cost factors that are not currently considered in the Power Purchase Agreement include the transmission interconnection cost, pipeline construction cost and the incremental costs being incurred to facilitate site preparation
 - as an offset to cost, NB Power is currently determining the amount of liquid fuel storage that is required on site
 - while all cost forecasts to date have included an assumption of 10 days of storage, the impact of reducing to a proposed 60 hours of storage will save NB Power [REDACTED] per year

Other financial considerations

- the rate impact in the first full year of operation is 4.98% (\$109 million)
- the revenue requirement excluding fuel over the 25 years is [REDACTED]
- the accounting treatment to be resolved in coming weeks but impact will be to the balance sheet
 - impact will be in the range of \$0 - [REDACTED]
- a \$10 million USD increase in CAPEX related to deviating soil conditions or added interconnect costs, you can consider approximately a [REDACTED] kW-month USD increase in the toll

**PROPOSED
RESOLUTION**

BE IT RESOLVED that the Strategic EOC approves

- 1) the pursuit of partnership option as the most viable to ensure capacity requirements can be met by November 2027
- 2) the pursuit of the RIGS partnership model with ProEnergy and the terms outlined in this briefing note

NEXT STEP

Assuming approval, the Business Development team will proceed with negotiations with ProEnergy to finalize a definitive tolling agreement and a property lease agreement.

Board of Directors approval of the partnership option and the terms outlined in this briefing note is scheduled for November 19, 2024.

When completing a final draft agreement, the business development team will come back to the Strategic EOC for approval to execute these agreements.

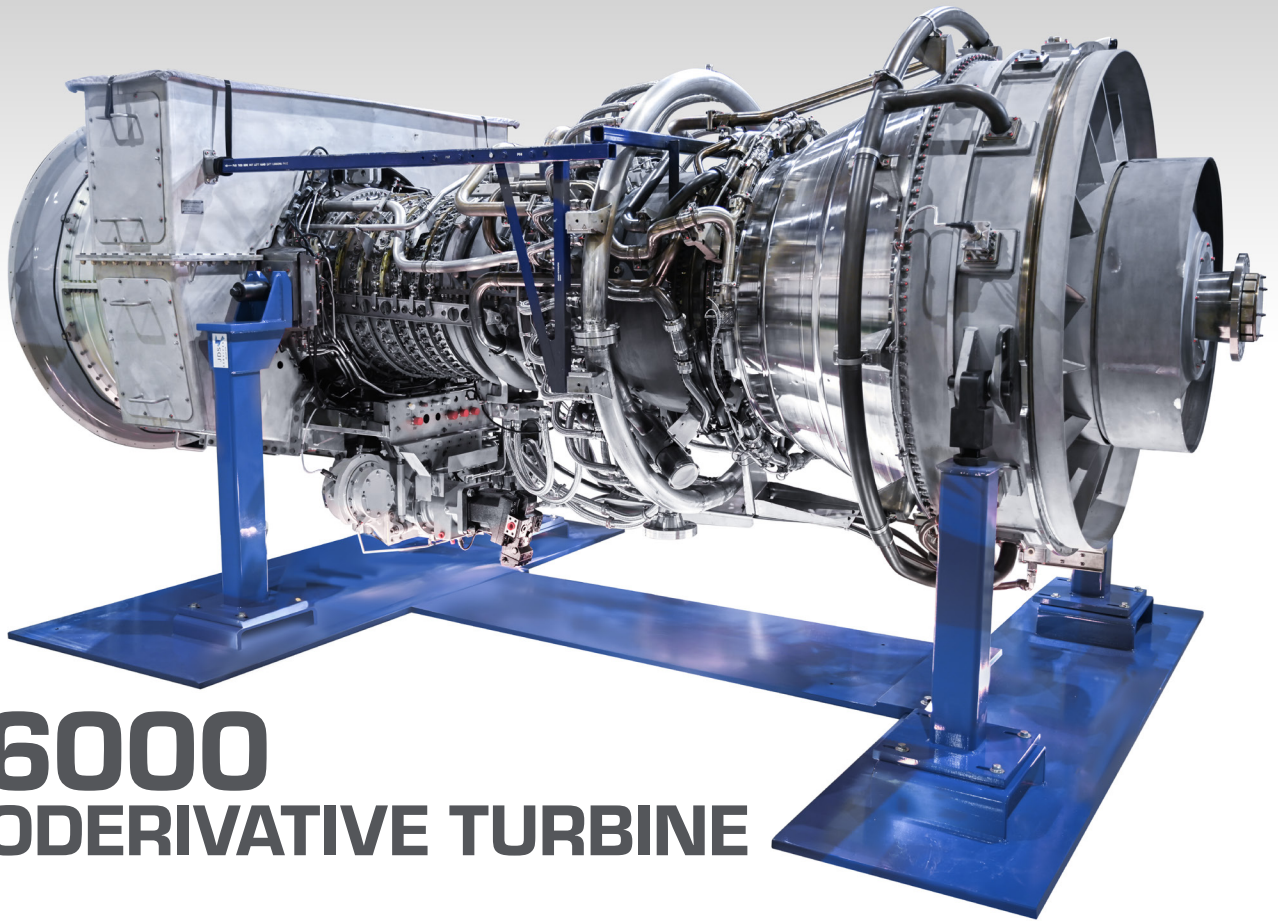
ATTACHMENTS

Appendix A contains the Energy Security Corporate Risk
Appendix B contains the Summary of terms of Tolling Agreement



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ProEnergy PE6000 Cut Sheet



PE6000 AERODERIVATIVE TURBINE

PARTS AND EQUIPMENT

THE ENGINE OF OUR INGENUITY

Dispatchable generation is the key to the energy transition. Leveraging unmatched in-house expertise in this technology, only PROENERGY gives flight engines new life in the power industry as PE6000 aeroderivative turbines.

Each 48 MW turbine starts as a CF6-80C2 engine core from aircraft including 747. Our experts overhaul the core in our world-class Sedalia campus and match it with aeroderivative parts manufactured by us or select partners to PROENERGY design and specification. This work ultimately delivers a robust supply of parts and components that are interchangeable with the LM6000 and ready to match your operating tempo.

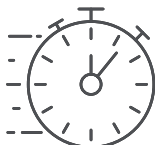
PE6000 SPECIFICATIONS

Dual frequency	50 or 60 Hz
Gross / Net output	49.6 MW / 48.8 MW*
Gross / Net heat rate	8,634 / 8,760 Btu/kWh (LHV)*
Dispatch time	<10 minutes
Fuel sources	Natural gas, LPG, or liquid distillate
Hydrogen capable	Up to 35%
Warranty	12–24 months

**Performance based on ISO conditions while operating at 60 Hz with natural gas fuel and water injection.*



MIGHTY
48 MW
OUTPUT



FAST
<10 MINUTE
FAST START



SUSTAINABLE
35% H₂
CAPABLE

VERIFIED PERFORMANCE

Proven at WattBridge and customer sites, the PE6000 aeroderivative turbine is the result of a comprehensive, multi-year development and validation program that covers every part, component, and engine.

Our internal expertise in LM technology and parts-repair processes is the foundation of PE6000 development. Through a significant investment in infrastructure and people, we further our R&D program by cultivating expertise in system and component design, materials engineering, and manufacturing excellence.

The PE6000 initiative emphasizes meticulous oversight both internally and with key supply partners. Our process—including a formal analytical evaluation of all design and materials, as well as nondestructive testing for every part and subsystem—culminates in years of commercial engine validation on multiple continents.

FROM AIRBORNE TO AERODERIVATIVE

The PE6000
expands part and
turbine availability.

DESIGN

Overhauled aircraft core with new PROENERGY parts

OPERATION

Emissions and air permitting identical to LM6000PC

PERFORMANCE

Efficient 8,760 Btu/kWh heat rate and hydrogen readiness



Our DMG MORI LASERTEC 125 DED hybrid machine supports rapid prototyping and manufacturing for the PE6000 and more.

YOUR CRITICAL PARTS ARE COVERED

Our advanced manufacturing program increases the parts supply for critical components like Stage 3-5 blades (right). These unique, in-house capabilities significantly reduce development time so that we produce quality, operations-ready parts in a fraction of the time of traditional processes.



MADE WITH PRIDE IN THE USA





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ProEnergy’s Technical and Production Data Sheets

THE POWER OF INGENUITY

Our Capabilities

PROENERGY

BUILT FOR THE ENERGY TRANSITION

PROENERGY is the sole vertically integrated aeroderivative solutions company and owner of the world's largest LM6000 commercial fleet.

We safely develop, build, and maintain dispatchable power generation at faster speeds, less cost, and higher reliability than anyone else.

ZERO BY CHOICE. NOT BY CHANCE.

Our safety journey is one of continuous improvement with a steadfast commitment to prevent injuries. Through intentional behaviors, actions, and tools, we cultivate a preventive mindset for any task at the jobsite or at home.



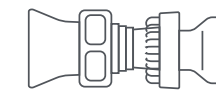
Topaz Generating Station (10X LM6000)

Power On Demand

Dispatchable power keeps the lights on during low solar and wind production. PROENERGY identified LM2500 and LM6000 aeroderivative turbines as ideal for this intermittency in the energy transition. These engines have proven to be exceptionally reliable, remarkably cost efficient, and infinitely repairable in skilled hands.

Aeroderivative turbines are the focus of our vertically integrated business.

Turbine Services



Repair and Overhaul Services. Few companies have a single-source repair, overhaul, and testing center. We have two.

Technical Services. Our technicians deploy 24/7/365 to any generating site in the world.

Parts Repair. Other companies outsource repairs all over the globe. About 90% of all parts remain on campus.

Engine Leases. We maintain an extensive inventory of LM6000 engines for customer use during turbine repair.

Equipment Manufacturing



Parts Manufacturing. We manufacture and machine new parts in our cutting-edge facility.

Engine Manufacturing. We overhaul aircraft engine cores and match them with our manufactured parts to deliver a 48 MW turbine.

Package Manufacturing. We transform raw steel into installation-ready units, including controls, accessories, and skids.

Plant Services and Ownership



Development. We have planned and built six power generation sites and counting.

Construction. Our in-house crews install plants twice as fast as any other EPC provider.

Startup and Commissioning. No other EPC company does it. We do it at record speed.

Operations and Maintenance. We manage customer plants like they're our own.

Monitoring. Few service companies have a NERC-compliant remote operating center. We have two.

Ownership. We own and operate the world's largest LM6000 fleet.

Decommissioning. We redeploy power plants anywhere in the world.

Our differentiators deliver impressive results.
PROENERGY leverages dedicated knowledge, innovative LM experts, and purpose-built facilities to produce unmatched value in every project.



Jeff Canon
President & CEO

People: Talent Throughout

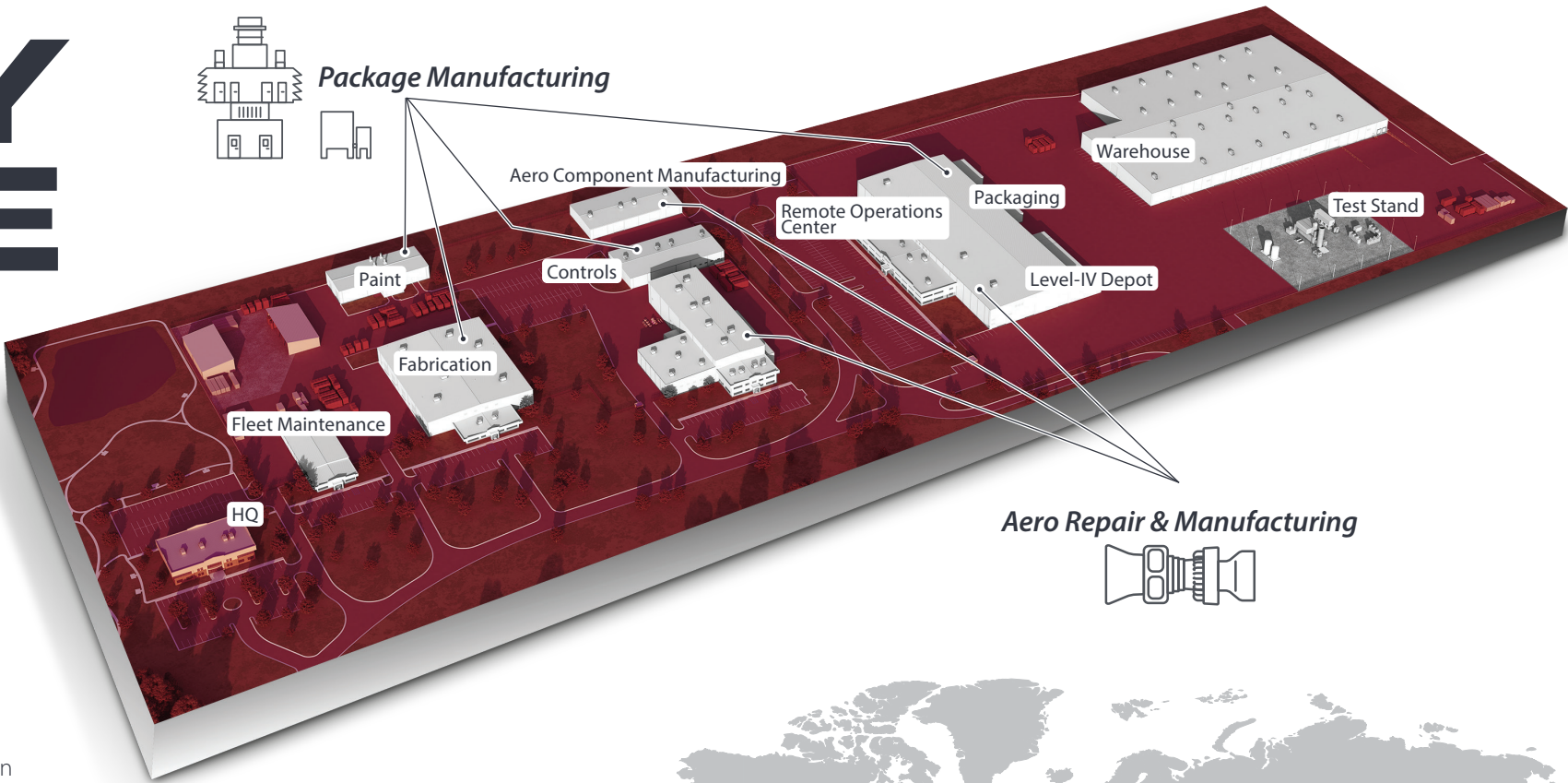
Our workforce is driven by exceptional talent. The PROENERGY leadership team sets the organization's pace by leveraging former positions as plant managers, senior engineers, and business leads going back to the first LM6000 installations. In parallel, our employees—from engineering experts to field technicians—continuously innovate to deliver value for our customers.

THE PROENERGY DIFFERENCE

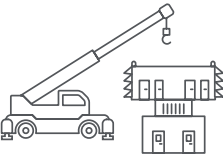
20+ YEARS
IN POWER GENERATION

40 COUNTRIES
WITH CUSTOMERS

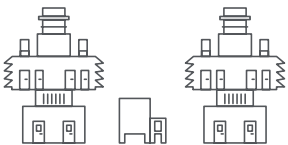
750+
EMPLOYEES WORLDWIDE



160+
MAJOR
MAINTENANCE
EVENTS



120+
TURNKEY
INSTALLATIONS



2,400 MW
ACTIVE POWER
GENERATION

Experience: Specialized Mastery

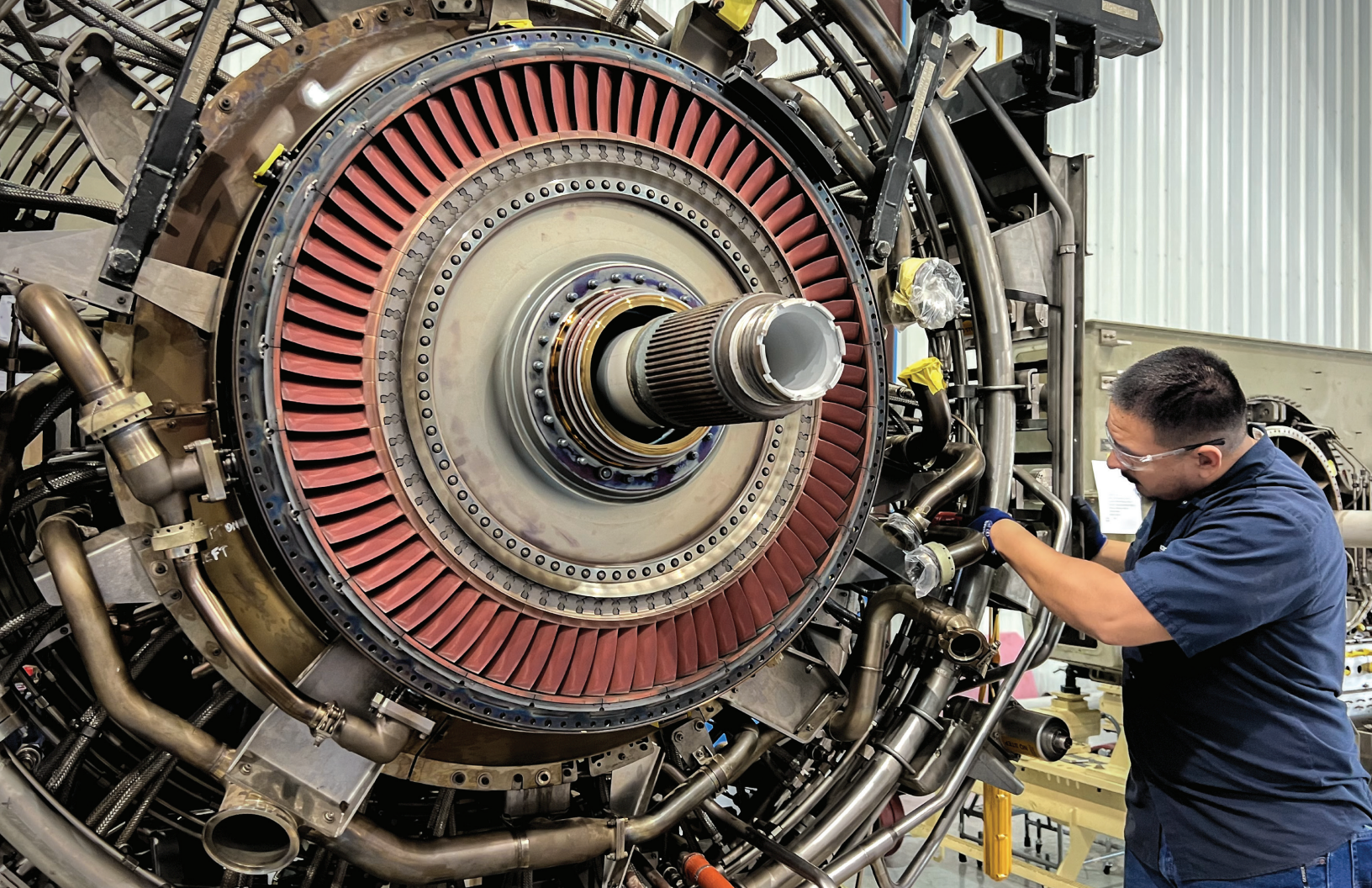
Our focus is singular. Over more than two decades, PROENERGY has acquired incomparable expertise on aeroderivative gas-turbine power plants worldwide. This deep, user-centered understanding results in new products, service strategies, and manufacturing techniques that support our customers in the energy transition.

Infrastructure: Strategic Support

Our headquarters is a global hub for aeroderivative excellence. Sitting on 90 acres in Sedalia, Missouri, the PROENERGY main campus offers life-of-turbine services, package and turbine manufacturing, and a home for our decarbonization programs. It features an independent Level-IV aeroderivative depot, a \$200 million parts and spares inventory, and a string-test facility for full-speed, full-load testing. Our second Level-IV depot in Houston, Texas, and our Level-II depot in Buenos Aires, Argentina, strengthen our service footprint.



● PROENERGY Facilities
○ Level-II Facilities in Development



THE POWER OF

PROENERGY

3

PROENERGY has a total focus on dispatchable aeroderivative technology. We offer industry-leading capabilities through our three market-facing businesses.

OUR BUSINESSES

1

AeroAdvantage

Our aeroderivative life-cycle services apply specialized experience and condition-based repair strategies to extend the life of LM6000 and LM2500 turbines. Leveraging the world's only independent Level-IV depot and LM6000 test cell, we repair, overhaul, manufacture, and service the global LM fleet.

Overhaul Services

- Depot Services
- Engine Testing

Parts & Equipment

- PE6000
- Lease Engines
- Parts Inventory
- Parts Pool
- Fuel Nozzles
- Water-Spray Injection Nozzles
- Parts Manufacturing

Technical Services

- Field Services
- Conversions, Modifications, & Upgrades
- DLE Tuning for LM6000PD
- Training

Operations & Maintenance (O&M)

- Onsite O&M
- Remote Operating Centers
- Compliance
- Mobilization

Asset Management

- Contract Management
- Financial Management
- Energy Management

Advanced Monitoring & Predictive Solutions (AMPS)

Total Care Services (TCSAs)

2

PowerFLX

Our standardized, aeroderivative plant design offers the leading construction speed and the lowest installed cost in the industry. Each plant harnesses our turnkey EPC+ services—including site preparation, structural foundations, facility construction, and commissioning—to deliver power generation on time and with proven reliability.

- Equipment & Manufacturing
- Standardized EPC+
- Balance of Plant Options
- Rental Power

3

WattBridge

Our independent power producer subsidiary develops projects and manages operational assets, including the world's largest LM6000 fleet. Its reduced-emissions, hydrogen-ready, dispatchable power facilities deliver repeatable energy security in any market.

- Project Development
- Asset Management
- Plant Ownership



PE6000: The Engine of Our Ingenuity

PROENERGY gives flight engines new life as fast-start dispatchable power. With every part and component manufactured to PROENERGY print and specification, the engine generates 48 MW with water-spray injection, enough for 40,000 homes. With several units installed for validation in Texas and further production ongoing, these engines provide energy reliability for millions.



Contact us for a tour of our Level-IV aeroderivative depots or
our power generation fleet.



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