Whenever. Wherever.
We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

October 7, 2026

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: Mike McNiven
Board Secretary

Dear Mr. McNiven:

Re: 2027 Wesleyville & Greenhill Thermal Generation Supplemental Application

Enclosed are the original and 10 copies of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2027 Wesleyville & Greenhill Thermal Generation Supplemental Application* (the "Application"). The Company seeks an order approving the Application.

The Application is filed in compliance with the *Public Utilities Act* (the "Act"), the regulations thereunder, and the Board's *Capital Budget Application Guidelines (Provisional)* effective January 2022 (the "Provisional Guidelines"). The Act, together with Newfoundland and Labrador Regulation 40/23, provides that a utility shall not proceed with any improvement or addition to its property where the cost exceeds $750,000 without prior approval of the Board. The Provisional Guidelines require, among other things, that proposed capital projects be organized by asset class and investment classification.

The Application comprises four capital projects. In compliance with the Act and the Provisional Guidelines, projects requiring capital expenditures greater than $750,000 are set out in Schedule B to the Application. Projects requiring capital expenditures $750,000 and under are outlined in Schedule C to the Application. Additional supporting materials are enclosed with the Application.

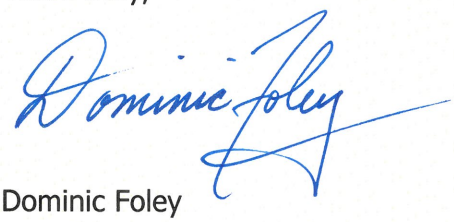
A copy of the Application has been forwarded directly to Ms. Shirley Walsh, Senior Legal Counsel of Newfoundland and Labrador Hydro, and Ms. Adrienne Ding, the Interim Consumer Advocate.

A PDF of the Application is available to the Board and interested parties via Newfoundland Power's stranded website at https://ftp.nfpower.nf.ca/. The Application is also publicly available via the Company's website (newfoundlandpower.com).

Newfoundland Power Inc.
55 Kenmount Road • P.O. Box 8910 • St. John's, NL A1B 3P6
PHONE (709) 737-5500 ext. 6200 • **FAX** (709) 737-2974 • **dfoley@newfoundlandpower.com**

We trust the foregoing and enclosed are in order. If you have any questions, please contact the undersigned.

Yours truly,



Dominic Foley
Legal Counsel

Enclosures

cc. Shirley Walsh
Newfoundland and Labrador Hydro

Adrienne Ding
O'Dea Earle

Newfoundland Power Inc.
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Newfoundland Power Inc.

2027 Wesleyville & Greenhill Thermal Generation Supplemental Application

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IN THE MATTER OF the *Public Utilities Act* (the "Act"); and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to section 41 of the Act approving supplemental capital expenditures required for the refurbishment of thermal facilities at Wesleyville and Greenhill.

2027 Capital Budget Supplemental Application

Whenever. Wherever. We'll be there.

NEWFOUNDLAND POWER
A FORTIS COMPANY

IN THE MATTER OF the *Public Utilities Act* (the "Act"); and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to section 41 of the Act approving supplemental capital expenditures required for the refurbishment of thermal facilities at Wesleyville and Greenhill.

TO: The Board of Commissioners of Public Utilities (the "Board")

THE APPLICATION OF Newfoundland Power Inc. (the "Applicant") **SAYS THAT:**

A. Background

1. The Applicant is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the Act, and is subject to the provisions of the *Electrical Power Control Act, 1994* (the "EPCA").

2. On May 29, 2026, the Applicant filed its 2027 Capital Budget Application in accordance with the Board's Capital Budget Guidelines (Provisional), effective January 2022. In its 2027 Capital Budget Application, the Applicant stated that it intended to file a supplemental application in 2026 for the refurbishment of the thermal generation facilities at Greenhill ("GRH") and Wesleyville ("WES").

B. The WES and GRH Facilities

3. The Applicant's WES facility comprises, among other things, a combustion turbine generator ("CTG"), fuel storage and handling system, auxiliary power unit ("APU"), on-site substation, main control building, and protection and control systems. The WES facility is located in the Town of New-Wes-Valley.

4. The Applicant's GRH facility comprises, among other things, a CTG, fuel storage and handling system, APU, on-site substation, main control building, and protection and control systems. The GRH facility is located in the Town of Grand Bank.

5. The WES and GRH facilities provide three principal functions on the Island Interconnected System ("IIS"): (i) local reliability support; (ii) regional transmission-system support; and (iii) firm, dispatchable capacity. The WES facility provides transmission-system support in Central Newfoundland and local reliability support to customers supplied by the Gambo–Wesleyville 66 kV transmission system. The GRH facility provides transmission voltage support and local reliability support on the Burin Peninsula. Both facilities also provide firm, dispatchable capacity to the IIS.

6. The Applicant retained Stantec Consulting Ltd. ("Stantec") to conduct condition assessments of the Applicant's thermal generation fleet. The condition assessments

concluded that the WES and GRH facilities are in poor overall condition and have reached the end of their service lives.

7. Given that the existing generating equipment and associated systems at the WES and GRH facilities have reached the end of their service lives, the Applicant conducted a Planning Study to assess alternatives for addressing their retirement and the resulting system requirements. The Planning Study concluded that retiring the WES and GRH facilities without replacement generation at those locations would require alternative investments to provide the capacity, transmission-support and local-reliability functions currently provided by the facilities.

8. The Planning Study included an assessment of alternatives which determined that refurbishing the WES and GRH facilities by installing replacement generation at the existing sites is the least cost alternative for meeting the capacity, transmission-system support and local-reliability requirements identified in the Planning Study. The proposed refurbishments would provide approximately 15 MW of firm, dispatchable capacity at WES and 30 MW at GRH, for approximately 45 MW in total, together with synchronous system-support capability.

9. To assess the technical options for replacing the WES and GRH CTGs, the Applicant retained Sargent & Lundy, LLC ("S&L") to evaluate a range of technically feasible replacement technologies capable of providing firm, dispatchable capacity and the synchronous system support required at the WES and GRH locations. The assessment concluded that CTG technology is the recommended replacement technology for WES and GRH because it provides firm, sustained, dispatchable capacity and synchronous system support at a lower estimated lifecycle cost than the other viable technology alternatives evaluated.

10. Based on the proposed unit configurations and anticipated operating profiles, the refurbishment of the WES and GRH facilities with modern CTG technology will be compliant with the applicable requirements of the Government of Canada's Clean Electricity Regulations, SOR/2024-263.

11. Newfoundland Power undertook early engagement with municipal representatives, local employers and other stakeholders in the Bonavista Bay north coast and Burin Peninsula regions concerning the condition of the existing facilities, the need for replacement generation, the proposed project scope and the reliability functions provided by the WES and GRH facilities. Newfoundland Power received 11 written expressions of support from municipal and business stakeholders in the two regions.

C. Application

12. Schedule A to this Application provides a summary of supplemental capital expenditures for which Newfoundland Power is seeking approval. The Application proposes multi-year projects commencing in 2027 with capital expenditures of $71,195,000 in 2027, $5,565,000 in 2028, $8,886,000 in 2029, $71,785,000 in 2030, and $84,658,000 in 2031.

13. The Board's Capital Budget Guidelines require, among other things, that proposed capital projects be organized by asset class and investment classification. In compliance with the Capital Budget Guidelines, the Application seeks approval of four capital projects. Schedule B to this Application provides detailed descriptions of the proposed projects in excess of $750,000. Schedule C to this Application outlines proposed expenditures under $750,000.

14. The Application includes supporting material in the form of a comprehensive engineering assessment report titled *Wesleyville and Greenhill Thermal Facility Refurbishments*. Stantec's condition assessment is included as Appendix A to the report. Appendix B includes historical capital upgrades at the WES and GRH facilities. Appendix C includes the Applicant's Planning Study. Appendix D includes S&L's Generation Technology Assessment. Appendix E includes Association for the Advancement of Cost Engineering (AACE) Class 3 cost estimates provided by Stantec to support the proposed capital expenditures for the WES and GRH refurbishments.

15. The proposed expenditures, as set out in Schedules A, B and C to this Application, are necessary for the Applicant to continue to provide service and facilities which are reasonably safe and adequate and are just and reasonable as required by section 37 of the Act.

16. The refurbishment of the WES and GRH facilities is consistent with the provincial power policy as defined in Section 3(b)(iii) of the *EPCA,* which requires power to be delivered to consumers in the province at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.

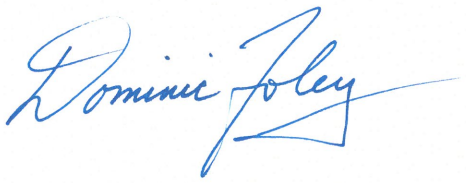
17. The Applicant requests that the Board make an Order, pursuant to section 41 of the Act, approving the Applicant's proposed multi-year construction and purchase of improvements or additions to its property for future years with capital expenditures in the amount of $71,195,000 in 2027, $5,565,000 in 2028, $8,886,000 in 2029, $71,785,000 in 2030, and $84,658,000 in 2031.

D. Communication

18. Communication with respect to this Application should be forwarded to the attention of Dominic Foley, Legal Counsel to the Applicant.

DATED at St. John's, Newfoundland and Labrador, this 7th day of October, 2026.

NEWFOUNDLAND POWER INC.



Dominic J. Foley, JD
Legal Counsel to Newfoundland Power Inc.
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55 Kenmount Road
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Telecopier: (709) 737-2974

dfoley@newfoundlandpower.com

IN THE MATTER OF the *Public Utilities Act* (the "Act"); and

IN THE MATTER OF an application by Newfoundland Power Inc. for an order pursuant to section 41 of the Act approving supplemental capital expenditures required for the refurbishment of thermal facilities at Wesleyville and Greenhill.

AFFIDAVIT

I, Byron Chubbs, of the Town of Paradise, in the Province of Newfoundland and Labrador, Professional Engineer, make oath and say as follows:

1. THAT I am Vice-President, Engineering and Energy Supply of Newfoundland Power Inc.;

2. THAT I have read and understand the foregoing Application; and

3. THAT, to the best of my knowledge, information and belief, all matters, facts and things set out in this Application are true.

SWORN TO before me at the City of St. John's in the Province of Newfoundland and Labrador this 7th day of October, 2026:

Dominic Foley
Barrister, NL

Byron Chubbs, P.Eng.

2027 CAPITAL BUDGET SUMMARY – SUPPLEMENTAL
MULTI-YEAR PROJECTS

Multi-Year Projects Commencing in 2027

Asset Class	Project Description	2027	2028	2029	2030	2031	Total
Substations	Wesleyville Substation Upgrades for Thermal Generation	-	-	-	46	436	482
Substations	Greenhill Substation Upgrades for Thermal Generation	-	-	-	613	7,289	7,902
Generation - Thermal	Wesleyville Thermal Generation Facility Refurbishment	24,789	2,053	2,796	25,030	31,195	85,863
Generation - Thermal	Greenhill Thermal Generation Facility Refurbishment	46,406	3,512	6,090	46,096	45,738	147,842
	Total	71,195	5,565	8,886	71,785	84,658	242,089

SCHEDULE B

2027 CAPITAL PROJECTS

OVER $750,000

SUBSTATIONS

Title:	**Greenhill Substation Upgrades for Thermal Generation**
Asset Class:	**Substations**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$613,000 in 2030; and $7,289,000 in 2031**

PROJECT DESCRIPTION

The *Greenhill Substation Upgrades for Thermal Generation* project involves the replacement of deteriorated equipment and the addition of new equipment at the Greenhill ("GRH") Substation located in the community of Grand Bank on the Burin Peninsula (the "GRH facility"). This work is required to facilitate the *Greenhill Thermal Generation Facility Refurbishment* project. Newfoundland Power Inc. ("Newfoundland Power" or the "Company") relied on inspections, engineering assessments, and operating experience to identify the necessary upgrades and equipment replacements included in the scope of work.

The proposed 2030 and 2031 scope of work for the *Greenhill Substation Upgrades for Thermal Generation* project includes the following work required to facilitate the *Greenhill Thermal Generation Facility Refurbishment* project:

1. Modify and extend existing 66 kV steel structure;
2. Install and commission a new 15/20/25 MVA, 66-13.8 kV power transformer at Greenhill Substation with required spill containment;
3. Construct new spill containment foundation for existing generation step-up transformer;
4. Install new 66 kV bus-tie breaker and associated disconnect switches;
5. Replace 66 kV air-break disconnect switches with motor-operated disconnect switches;
6. Install new 13.8 kV disconnect switches;
7. Replace obsolete electromechanical relays with new digital relays; and
8. Upgrade and extend the ground grid.

Engineering design and procurement of long lead time equipment will be completed in 2030. Construction will begin in the third quarter of 2030 and will be completed in the fourth quarter of 2031. Commissioning will be completed during the fourth quarter of 2031.

PROJECT BUDGET

The budget for the *Greenhill Substation Upgrades for Thermal Generation* project is based on detailed engineering estimates.

Table 1 provides a breakdown of expenditures proposed for 2030 and 2031 for the *Greenhill Substation Upgrades for Thermal Generation* project.

Table 1
Greenhill Substation Upgrades for Thermal Generation Project
2027-2031 Budget
($000s)

Cost Category	2027	2028	2029	2030	2031	Total
Material	-	-	-	321	6,149	6,470
Labour – Internal	-	-	-	5	70	75
Labour – Contract	-	-	-	-	-	-
Engineering	-	-	-	269	471	740
Other	-	-	-	18	599	617
Total	**-**	**-**	**-**	**613**	**7,289**	**7,902**

Proposed expenditures for the *Greenhill Substation Upgrades for Thermal Generation* project are $613,000 in 2030 and $7,289,000 in 2031 for a total project budget of $7,902,000.

ASSET BACKGROUND

The existing GRH thermal generation facility provides generation support to the 66 kV Burin Peninsula Transmission System and is interconnected with the system through the GRH Substation and a single generation step-up transformer. The *Greenhill Thermal Generation Facility Refurbishment* project requires refurbishment and expansion of the GRH Substation to maintain integration of the refurbished GRH facility. The refurbished generation facility will be comprised of two new 15 MW combustion turbine generators ("CTGs"). Accordingly, the GRH Substation will require expansion and modification to accommodate the revised generation configuration.

GRH Substation was constructed in 1975 as a generation, transmission, and distribution substation. In addition to providing the transmission interconnection of the GRH facility, the substation provides local distribution service to approximately 2,300 customers in the Grand Bank area.

Beginning in 2030, Newfoundland Power is proposing to upgrade the GRH Substation to facilitate the *Greenhill Thermal Generation Facility Refurbishment* project. The proposed work includes installation of a second generator step-up transformer, modifications and expansion of existing 66 kV infrastructure, installation of new power transformer spill containments, addition of 13.8 kV infrastructure, and modifications to the existing protection, control and communication systems. Expansion of the substation yard and associated site work will also be required to accommodate the revised substation configuration.

ASSESSMENT OF ALTERNATIVES

The *Greenhill Thermal Generation Facility Refurbishment* project requires modifications to the GRH Substation to integrate the reconfigured generation facility with the existing 66 kV system. The existing substation configuration supports a single generator step-up transformer and associated substation infrastructure.

Retaining the existing substation configuration would not accommodate the proposed generation arrangement and is therefore not a viable alternative. The installation of the second generator step-up transformer requires expansion of the existing 66 kV arrangement and associated modifications to the substation yard, protection and control systems, and supporting infrastructure.

The proposed work has been limited to the substation modifications required to accommodate the *Greenhill Thermal Generation Facility Refurbishment* project. A Substation Refurbishment and Modernization project will be proposed as part of the *2030 Capital Budget Application* that evaluates the replacement of equipment, based on condition, which is not required to accommodate the new generation configuration.[1] The existing 66 kV air-break switch associated with the generator step-up transformer and generator electromechanical protection relays are aged or obsolete and will be replaced as part of the required modifications.

RISK ASSESSMENT

The *Greenhill Substation Upgrades for Thermal Generation* project will mitigate risks associated with integrating the GRH facility with the existing 66 kV Burin Peninsula Transmission System. GRH Substation serves approximately 2,300 distribution customers in the Grand Bank area while acting as the electrical interface between the generating facility and the 66 kV transmission system. The substation modifications are required to maintain the safe and reliable operation of both the generation and distribution functions of GRH Substation.

The refurbished GRH facility will comprise two new 15 MW CTGs connected to the 66 kV system through the existing and new generator step-up transformers. The existing substation arrangement was designed for a single generator step-up transformer and does not accommodate the proposed CTG configuration. Expansion of the 66 kV bus arrangement, including the addition of a bus-tie breaker and associated disconnect switches, is required to provide the switching, isolation, and sectionalizing capability necessary for operating this new configuration. Without these modifications, the refurbished generating facility cannot be reliably integrated with the existing 66 kV system.

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[1] The forecasted cost of the 2030 *Greenhill Substation Refurbishment and Modernization* project is estimated to be $111,000 in 2030 and $2,515,000 in 2031 for a total project budget of $2,626,000. This project was not included in the scope of *Greenhill Substation Upgrades for Thermal Generation* project for the following reasons: i) equipment in the scope of the *2030 Greenhill Substation Refurbishment and Modernization* project is not required to accommodate the refurbishment of the GRH facility; ii) some of the equipment in the scope of the *2030 Greenhill Substation Refurbishment and Modernization* project may be replaced under in-service failures before 2030; iii) the project can be developed closer to execution, when scope, equipment requirements and cost estimates can be established with greater certainty, while still accommodating anticipated equipment lead times.

The proposed work also interfaces with existing equipment that is deteriorated or obsolete. The 66 kV air-break switch associated with the existing generator step-up transformer is 49 years old and will be replaced as part of the required modifications. A new 13.8 kV disconnect switch will also be installed to provide complete isolation of the existing generator step-up transformer from the generating facility. These modifications will provide appropriate isolation and switching capability for operation and maintenance of the reconfigured generation connection.

The existing generator protection system includes electromechanical relays that are 46 years old on average and are obsolete. Modification of the protection system is required to accommodate the new generation configuration. The affected electromechanical relays will be replaced with modern digital relays consistent with Newfoundland Power's current protection and control standards. This will provide appropriate protection for the new configuration and mitigate the operational risk associated with continued reliance on obsolete protection equipment.

The existing generator step-up transformer contains insulating oil and is not equipped with spill containment. As work is required at the transformer connection to accommodate the refurbished GRH facility, spill containment will be installed to mitigate the environmental and safety consequences of a transformer oil release.

Expansion of the substation yard to accommodate the additional generator step-up transformer and associated 66 kV equipment will also require corresponding expansion of the ground grid, perimeter fencing, and cable trench system. These modifications are necessary to maintain grounding, physical security and cable infrastructure appropriate for the expanded substation footprint.

Failure to complete the required substation modifications would prevent the refurbished GRH facility from being appropriately integrated with the 66 kV Burin Peninsula transmission system and would affect Newfoundland Power's ability to obtain the intended generation support from the refurbished GRH facility. The proposed work mitigates these risks by providing the substation infrastructure, switching, isolation, protection, and environmental measures required for the new generation configuration.

Table 2 summarizes the risk assessment for the *Greenhill Substation Upgrades for Thermal Generation* project.

Table 2
Greenhill Substation Upgrades for Thermal Generation
Project Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Near Certain (5)	High (25)

Overall, failure to complete the *Greenhill Substation Upgrades for Thermal Generation* project poses a High (25) risk to the delivery of reliable, safe, and environmentally responsible service to customers. Action is required in 2030 and 2031 to mitigate these risks for customers.

JUSTIFICATION

The *Greenhill Substation Upgrades for Thermal Generation* project is required to accommodate the refurbishment of the GRH facility and integrate the new generation configuration with the existing 66 kV Burin Peninsula transmission system. The proposed work will provide the additional transformer connection, switching, isolation, protection and associated substation infrastructure required to safely and reliably transfer generation from the refurbished GRH facility to the 66 kV transmission system.

GENERATION - THERMAL

Title:	**Greenhill Thermal Generation Facility Refurbishment**
Asset Class:	**Generation - Thermal**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$46,406,000 in 2027; $3,512,000 in 2028; $6,090,000 in 2029; $46,096,000 in 2030; and $45,738,000 in 2031**

PROJECT DESCRIPTION

The *Greenhill Thermal Generation Facility Refurbishment* project involves the refurbishment of the Newfoundland Power GRH thermal generating facility located in the community of Grand Bank on the Burin Peninsula.

The proposed 2027 through 2031 scope of work for the *Greenhill Thermal Generation Facility Refurbishment* includes:

1. Installation of two 15 MW CTGs;
2. Replacing fuel storage and fuel forwarding systems;
3. Installation of a new auxiliary power unit;
4. Yard expansion;
5. Removal of existing building;
6. Construction of a new auxiliary building;
7. Replacement of switchgear; and
8. Installation of new protection and controls equipment.

Years one through three are anticipated to focus on detailed engineering, development of equipment specifications, tendering activities, and procurement of long-lead time equipment. This period also includes advancement of project planning and preparation of construction packages. Year four is expected to focus on site preparation activities, including civil and structural works, yard expansion, and building works. Year five is expected to encompass construction, installation of mechanical and electrical systems, commissioning, and integration of the new facilities into service.

For additional details, see the report titled *Wesleyville and Greenhill Thermal Facility Refurbishments*, included as supporting material to the Application.

PROJECT BUDGET

The budget for the *Greenhill Thermal Generation Facility Refurbishment* project is based on detailed engineering estimates. Table 1 provides a breakdown of expenditures proposed for 2027 through 2031 for the *Greenhill Thermal Generation Facility Refurbishment* project.

Table 1 Greenhill Thermal Generation Facility Refurbishment Project 2027-2031 Budget ($000s)						
Cost Category	**2027**	**2028**	**2029**	**2030**	**2031**	**Total**
Material	36,992	-	2,485	39,036	33,345	111,858
Labour – Internal	95	99	104	235	1,301	1,834
Labour – Contract	-	-	-	-	-	-
Engineering	245	256	268	466	1,072	2,307
Other	9,074	3,157	3,233	6,359	10,020	31,843
Total	**46,406**	**3,512**	**6,090**	**46,096**	**45,738**	**147,842**

Proposed expenditures for the *Greenhill Thermal Generation Facility Refurbishment* project include $46,406,000 in 2027, $3,512,000 in 2028, $6,090,000 in 2029, $46,096,000 in 2030, and $45,738,000 in 2031 for a total project budget of $147,842,000.

ASSET BACKGROUND

The GRH facility is located in the Town of Grand Bank on the Burin Peninsula. The Burin Peninsula transmission system is supplied from Newfoundland and Labrador Hydro's ("Hydro") Sunnyside Terminal Station via 138 kV transmission lines TL-212 and TL-219. The GRH facility is connected to the Island Integrated System ("IIS") via transmission lines 301L and 305L, which operate at 66 kV.

Figure 1 shows the location of the GRH facility and the transmission system supplying the area.

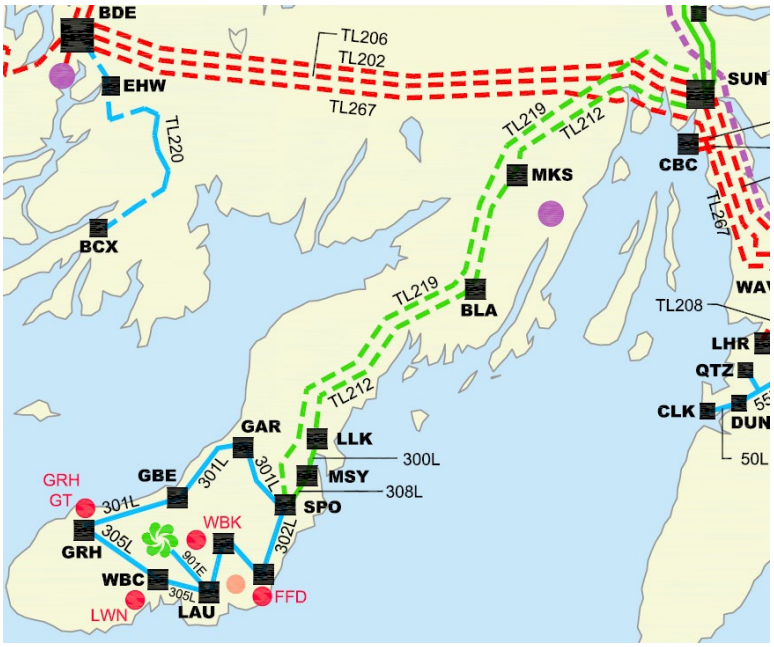


Figure 1 – Burin Peninsula Transmission System

Figure 2 shows the GRH facility.



Figure 2 – Greenhill Thermal Generation Facility

The GRH CTG was commissioned in 1975 and is currently rated at 20 MW.

The GRH facility provides backup generation during transmission outages and can support local customer loads when transmission infrastructure is not available. The GRH facility is also used for emergency generation and system support during peak load conditions. Historically, the GRH facility has been in production for both Hydro as well as Newfoundland Power to support the IIS for firm generation capacity.

Since entering service in 1975, the GRH facility has undergone multiple upgrades. Approximately $2.0 million has been invested into the GRH facility from 2006 to 2025.[2] Despite these investments, the unit is exhibiting increasing deterioration and declining performance. The GRH CTG has been derated from its original 25 MW rating to 20 MW. A condition assessment of the GRH facility was completed by Stantec Consulting Ltd. ("Stantec") in 2026 (the "condition assessment").[3] The condition assessment determined that multiple components of the GRH facility, including the CTG, are in poor overall condition and have reached the end of their service life due to the age, condition, and lack of vendor support.[4]

[2] See the *supporting material*, Appendix B, Table B-2.
[3] Stantec's report titled *Thermal Generation Fleet Review*, dated May 4, 2026, is included as Appendix A of the supporting material.
[4] *Ibid.*

ASSESSMENT OF ALTERNATIVES

Newfoundland Power completed an assessment of alternatives to determine the least-cost solution to address the local reliability, regional transmission support, and system capacity functions currently provided by the end-of-service-life GRH facility. The Company also completed a technology assessment to determine the recommended technology alternative for refurbishment of the existing facilities.

Newfoundland Power completed the *2027 Wesleyville & Greenhill Planning Study* (the "Planning Study"), dated October 2026, to determine the long-term system requirements associated with retirement of the existing GRH facility.[5] The Planning Study assessed the contribution of the GRH facility to local reliability, transmission system performance, and firm, dispatchable capacity on the IIS, and evaluated alternatives to maintain these functions following retirement of the existing facility. These alternatives included: (i) refurbishing the GRH facility by retiring the existing CTG and installing a new source of firm, dispatchable generation; and (ii) retiring the generation facility and addressing system requirements through other investments, including transformer upgrades, reactive power support, transmission line modifications, and additional firm, dispatchable capacity elsewhere on the IIS. The Planning Study determined that refurbishment of the GRH facility with new firm, dispatchable generation represents the least-cost solution for maintaining local reliability, supporting the regional transmission system in Central Newfoundland and on the Burin Peninsula, and providing firm, dispatchable capacity on the IIS.[6]

Newfoundland Power retained Sargent & Lundy ("S&L") to evaluate technology alternatives capable of providing the required generation capacity and system support at the GRH facility.[7] The alternatives assessed included replacement with: (i) CTGs; (ii) reciprocating internal combustion engines ("RICE"); and (iii) battery energy storage systems ("BESS").[8] The Company also evaluated: (iv) maintaining the existing CTG; and (v) retiring the CTG without replacement.[9] The assessment concluded that CTG technology is the recommended alternative as it provides the required firm, dispatchable capacity and synchronous system support while offering lower estimated lifecycle costs, reduced implementation complexity, and greater maintenance flexibility relative to the other technically feasible alternatives.

RISK ASSESSMENT

The *Greenhill Thermal Generation Facility Refurbishment* project will mitigate risks to the delivery of reliable service by addressing deteriorated and end-of-service-life equipment.

The GRH facility provides local reliability and transmission-system support on the Burin Peninsula and firm, dispatchable capacity on the IIS. Condition assessments concluded that the

5 The Planning Study is included as Appendix C of the supporting material.
6 *Ibid.*
7 S&L is an engineering consulting firm with experience in the planning, design, construction, and implementation of power and energy infrastructure projects. The report titled *Generation Technology Assessment*, dated September 10, 2026 (the "S&L Report"), included as Appendix D of the supporting material.
8 *Ibid.*
9 See *Section 6.0 Assessment of Alternatives* of the *Wesleyville and Greenhill Thermal Facility Refurbishments* report.

facility has reached the end of its service life and identified significant deterioration, operational limitations, and limited vendor support for critical equipment. Replacement capacity capable of providing sustained output and system support is required to maintain system reliability and compliance with planning criteria.

The consequences associated with retirement of the GRH facility extend beyond localized impacts and include the loss of local generation support on the Burin Peninsula, reduced regional transmission support during contingency events, and a reduction in firm, dispatchable capacity available to the IIS.

Table 2 summarizes the risk assessment of the 2027 *Greenhill Thermal Generation Facility Refurbishment* project.

Table 2
Greenhill Thermal Generation Facility Refurbishment
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Near Certain (5)	High (25)

Based on this assessment, not proceeding with the *Greenhill Thermal Generation Facility Refurbishment* project would pose a High (25) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Greenhill Thermal Generation Facility Refurbishment* project is necessary to replace end-of-service-life generating equipment and maintain the local reliability, transmission-system support, and firm, dispatchable IIS capacity functions provided by the GRH facility. The project will install two nominal 15 MW CTGs, providing approximately 30 MW of firm, dispatchable capacity together with synchronous system support, including synchronous condenser capability. This will maintain local reliability and transmission-system voltage support on the Burin Peninsula while contributing firm, dispatchable capacity to the IIS.

Title:	**Wesleyville Thermal Generation Facility Refurbishment**
Asset Class:	**Generation - Thermal**
Category:	**Project**
Investment Classification:	**Renewal**
Budget (Multi-Year):	**$24,789,000 in 2027; $2,053,000 in 2028; $2,796,000 in 2029; $25,030,000 in 2030; and $31,195,000 in 2031**

PROJECT DESCRIPTION

The *Wesleyville Thermal Generation Facility Refurbishment* project involves the refurbishment of the Newfoundland Power thermal generating facility at Wesleyville ("WES") located in the town of New-Wes-Valley on the north coast of Bonavista Bay (the "WES facility").

The proposed 2027 through 2031 scope of work for the *Wesleyville Thermal Generation Facility Refurbishment* includes:

1. Installation of a new 15 MW CTG;
2. Replacing fuel storage and fuel forwarding systems;
3. Installation of a new auxiliary power unit;
4. Yard expansion;
5. Modification to existing building;
6. Installation of new switchgear; and
7. Installation of new protection and controls equipment.

Years one through three are anticipated to focus on detailed engineering, development of equipment specifications, tendering activities, and procurement of long-lead time equipment. This period also includes advancement of project planning and preparation of construction packages. Year four is expected to focus on site preparation activities, including civil and structural works, yard expansion, and building works. Year five is expected to encompass construction, installation of mechanical and electrical systems, commissioning, and integration of the new facility into service.

For additional details, see the report titled *Wesleyville and Greenhill Thermal Facility Refurbishments*, included as supporting material to the Application.

PROJECT BUDGET

The budget for the *Wesleyville Thermal Generation Facility Refurbishment* project is based on detailed engineering estimates. Table 1 provides a breakdown of expenditures proposed for 2027 through 2031 for the *Wesleyville Thermal Generation Facility Refurbishment* project.

Table 1 Wesleyville Thermal Generation Facility Refurbishment Project 2027-2031 Budget ($000s)						
Cost Category	2027	2028	2029	2030	2031	Total
Material	18,451	-	678	20,653	22,732	62,514
Labour – Internal	79	83	86	196	1,086	1,530
Labour – Contract	-	-	-	-	-	-
Engineering	239	249	261	454	1,044	2,247
Other	6,020	1,721	1,771	3,727	6,333	19,572
Total	**24,789**	**2,053**	**2,796**	**25,030**	**31,195**	**85,863**

Proposed expenditures for the *Wesleyville Thermal Generation Facility Refurbishment* project are $24,789,000 in 2027, $2,053,000 in 2028, $2,796,000 in 2029, $25,030,000 in 2030, and $31,195,000 in 2031 for a total project budget of $85,863,000.

ASSET BACKGROUND

The WES facility is located in the Town of New-Wes-Valley on the north coast of Bonavista Bay. The facility is connected to the IIS via 66 kV transmission lines 116L and 115L.

Figure 1 below shows the 115L/116L transmission system supplying the area.

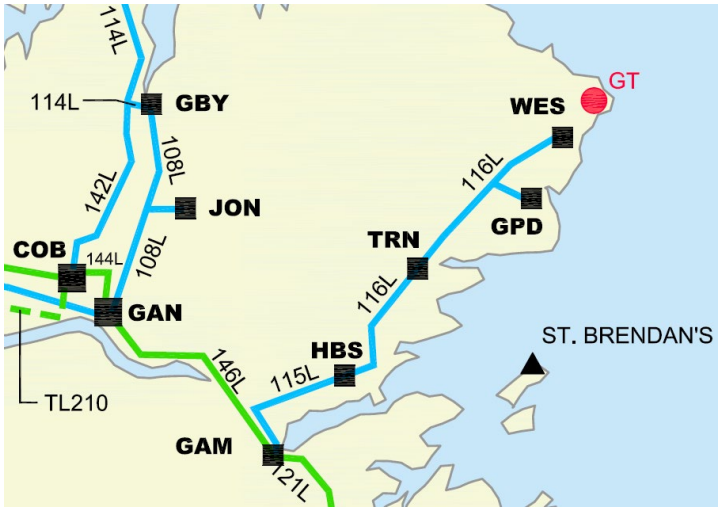


Figure 1 – 115/116L Transmission System

Figure 2 below shows the WES facility.



Figure 2 – Wesleyville Thermal Generation Facility

The WES CTG was manufactured by Associated Electrical Industries and was installed in the community of Salt Pond on the Burin Peninsula in 1969. In 2003, the unit was relocated to the Town of New-Wes-Valley on the north coast of Bonavista Bay where it remains. The WES facility was originally designed with a generating capacity of 14.7 MW.

The radial configuration of the Gambo-Wesleyville 66 kV transmission system results in reliance on local generation at WES for reliability support during certain transmission outages. The WES facility provides backup generation during transmission outages and can support local customer loads when transmission infrastructure is not available. The WES facility is also used for emergency generation and system support during peak load conditions. Historically, the WES facility has been in production for both Hydro as well as Newfoundland Power to support the IIS for firm, dispatchable capacity.

The WES facility has undergone multiple upgrades since its relocation in 2003. Approximately $3.2 million has been invested into the facility from 2006 to 2025.[10] Despite these investments, the WES facility is exhibiting increasing deterioration and declining performance. The WES CTG has been derated from its original 14.7 MW rating to 8 MW. A condition assessment of the WES facility was completed by Stantec in 2026.[11] The condition assessment determined that multiple components of the WES facility, including the WES CTG, are in poor overall condition and have reached the end of their service life due to the age, condition, and lack of vendor support.[12]

ASSESSMENT OF ALTERNATIVES

Newfoundland Power completed an assessment of alternatives to determine the least-cost solution to address the local reliability, regional transmission support, and system capacity functions currently provided by the end-of-service-life WES facility. The Company also completed a technology assessment to determine the recommended technology alternative for refurbishment of the existing facilities.

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10 See Appendix B, Table B-1 of the supporting material.

11 Stantec's report titled *Thermal Generation Fleet Review*, dated May 4, 2026, is included as Appendix A of the supporting material.

12 *Ibid*.

Newfoundland Power completed a Planning Study to determine the long-term system requirements associated with retirement of the existing WES facility.[13] The Planning Study assessed the contribution of the WES facility to local reliability, transmission system performance, and firm, dispatchable capacity on the IIS, and evaluated alternatives to maintain these functions following retirement of the existing facility.[14] These alternatives included: (i) refurbishing the WES facility by retiring the existing CTG and installing a new source of firm, dispatchable generation; and (ii) retiring the generation facility and addressing system requirements through other investments, including transformer upgrades, reactive power support, transmission line modifications, and additional firm, dispatchable capacity elsewhere on the IIS. The Planning Study determined that refurbishment of the WES facility with new firm, dispatchable generation represents the least-cost solution for maintaining local reliability, supporting the regional transmission system in Central Newfoundland, and preserving firm, dispatchable capacity on the IIS.[15]

Newfoundland Power retained S&L to evaluate technology alternatives capable of providing the required generation capacity and system support at the WES facility.[16] The alternatives assessed included replacement with: (i) CTGs; (ii) RICE; and (iii) BESS.[17] The Company also evaluated: (iv) maintaining the existing CTG; and (v) retiring the CTG without replacement.[18] The assessment concluded that CTG technology is the recommended alternative as it provides the required firm, dispatchable capacity and synchronous system support while offering lower estimated lifecycle costs, reduced implementation complexity, and greater maintenance flexibility relative to the other technically feasible alternatives.

RISK ASSESSMENT

The *Wesleyville Thermal Generation Facility Refurbishment* project will mitigate risks to the delivery of reliable service by addressing deteriorated and end-of-service-life equipment.

The WES facility provides local reliability benefits for customers on the Bonavista Bay north coast, regional support for the Central Newfoundland transmission network, and firm, dispatchable capacity on the IIS. Condition assessments concluded that the facility has reached the end of its service life and identified significant deterioration, operational limitations, and limited vendor support for critical equipment. Replacement capacity capable of providing sustained output and system support is required to maintain system reliability and compliance with planning criteria.

The consequences associated with retirement of the WES facility extend beyond localized impacts and include the loss of local generation support for customers supplied by the Gambo-Wesleyville 66 kV transmission system, reduced regional transmission support in Central

13 The Planning Study is included as Appendix C of the supporting material.
14 *Ibid.*
15 *Ibid.*
16 The report titled *Generation Technology Assessment*, dated September 10, 2026, included as Appendix D of the supporting material.
17 *Ibid.*
18 See *Section 6.0 Assessment of Alternatives* of the *Wesleyville and Greenhill Thermal Facility Refurbishments* report.

Newfoundland during contingency events, and a reduction in firm, dispatchable capacity available to the IIS.

Table 2 summarizes the risk assessment of the 2027 *Wesleyville Thermal Generation Facility Refurbishment* project.

Table 2
Wesleyville Thermal Generation Facility Refurbishment
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Near Certain (5)	High (25)

Based on this assessment, not proceeding with the *Wesleyville Thermal Generation Facility Refurbishment* project would pose a High (25) risk to the delivery of reliable service to customers.

JUSTIFICATION

The *Wesleyville Thermal Generation Facility Refurbishment* project is necessary to replace end-of-service-life generating equipment and maintain the local reliability, transmission-system support, and firm, dispatchable IIS capacity functions provided by the WES facility. The project will install one nominal 15 MW CTG, providing approximately 15 MW of firm, dispatchable capacity together with synchronous system support, including synchronous condenser capability. This will maintain local reliability support for the Gambo-Wesleyville 66 kV transmission system and transmission-system support in Central Newfoundland while contributing firm, dispatchable capacity to the IIS.

SCHEDULE C

2027 CAPITAL PROJECTS

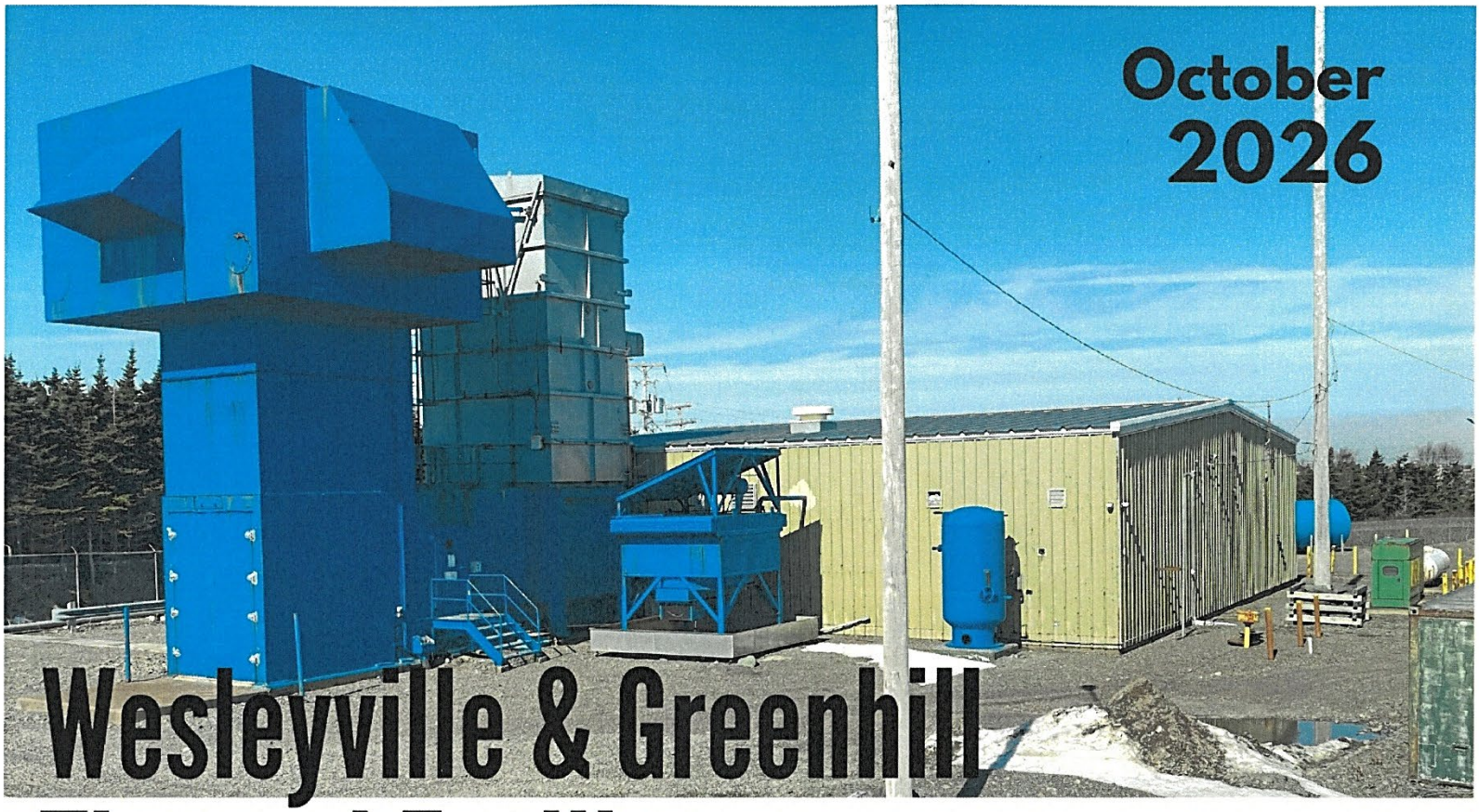
$750,000 AND UNDER

Substations

Wesleyville Substation Upgrades for Thermal Generation

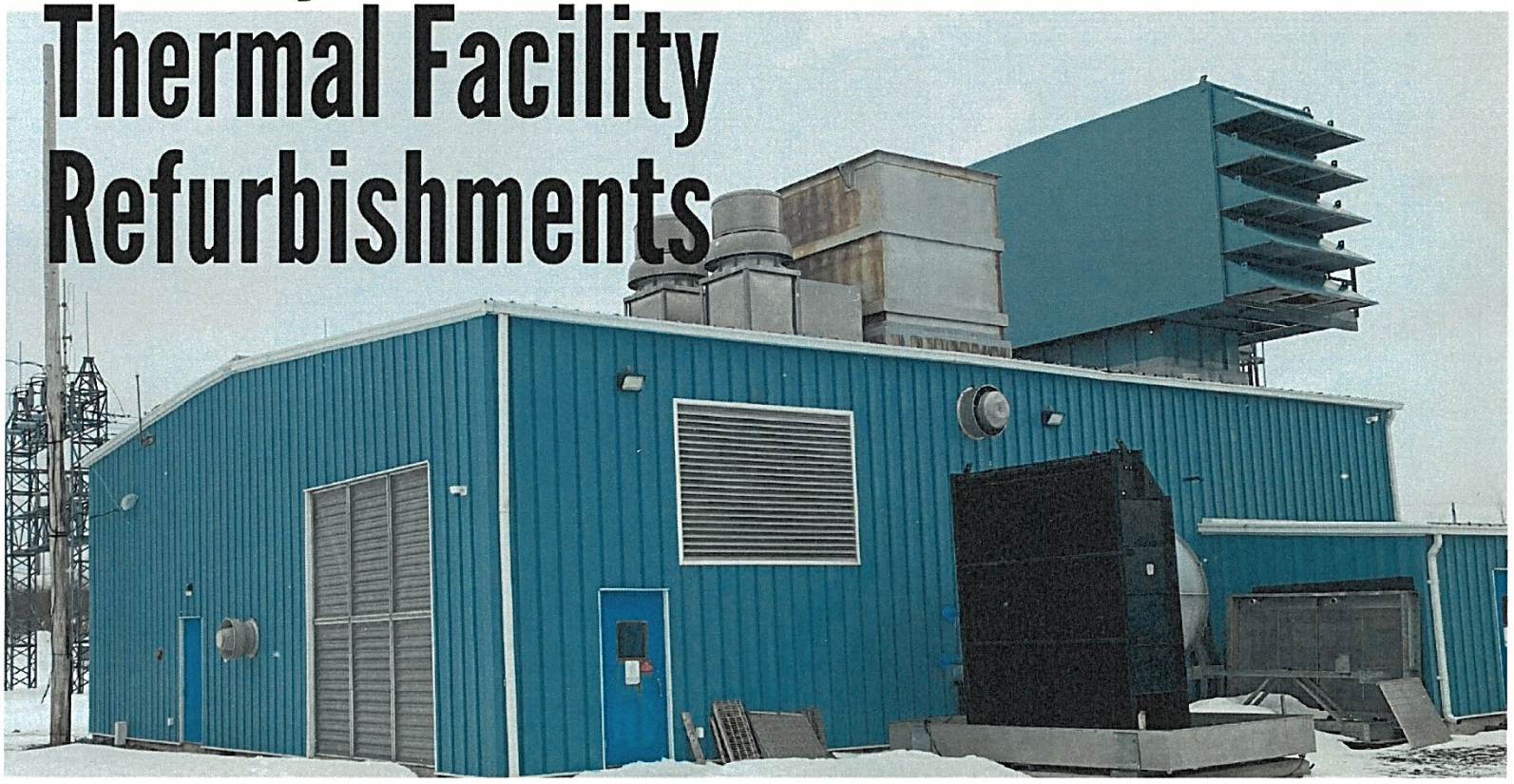
Budget: *$46,000 in 2030; $436,000 in 2031*
Investment Classification: *Renewal*
Category: *Multi-Year Project*

This project involves the replacement of deteriorated disconnect switches, the removal of an obsolete circuit breaker, site work in Wesleyville Substation, and uprating of the plant power transformer through the installation of cooling fans to facilitate the *Wesleyville Thermal Generation Facility Refurbishment* project at the Wesleyville Thermal Generation Facility.



October
2026

Wesleyville & Greenhill Thermal Facility Refurbishments



Prepared by:

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NEWFOUNDLAND POWER
A FORTIS COMPANY

EXECUTIVE SUMMARY

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") operates a fleet of thermal generating facilities. Two of these facilities are located in Wesleyville ("WES") on the Bonavista Bay north coast and Greenhill ("GRH") on the Burin Peninsula. The generating equipment and associated systems at the WES and GRH thermal generation facilities have reached the end of their service lives and require refurbishment.[1] The WES combustion turbine generator ("CTG") and GRH CTG were originally brought into service in 1969 and 1975, respectively. The current condition of the WES and GRH facilities poses increasing risks to local and system reliability during peak-demand and contingency conditions.

Condition assessments completed by a third-party engineering consultant confirm that critical components of the WES and GRH facilities are in overall poor condition, have reached the end of their service lives, and should be retired. The facilities exhibit progressive deterioration of critical systems, limited availability of replacement parts, and reduced reliability and operational capability. These conditions create increased reliability risk and operational uncertainty regarding the continued availability of the facilities to support customers on the Island Interconnected System ("IIS").

The WES and GRH facilities serve multiple functions on the IIS, including: (i) local reliability support for rural communities; (ii) regional support for the Central Newfoundland transmission network; and (iii) IIS capacity during peak demand and contingency conditions. Retirement and decommissioning of the WES and GRH facilities would necessitate additional investments in the electrical system. The functions of the WES and GRH facilities on the IIS are summarized in Figure 1.

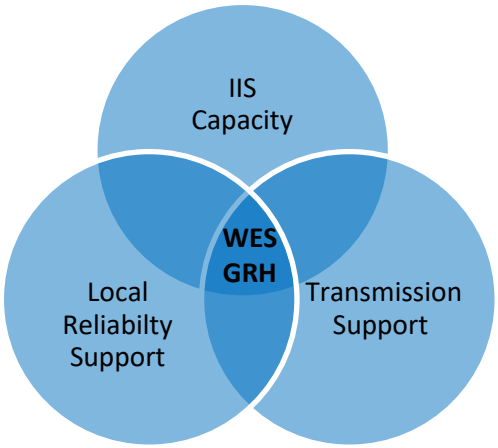


Figure 1 - Wesleyville & Greenhill Combustion Turbine Functions

[1] For the purposes of this report, "facility refurbishment" refers to the retirement and removal of the existing combustion turbine generating equipment and the installation of new combustion turbine generation and associated balance-of-plant, building, electrical, protection, control, and substation assets at the existing sites.

The *2027 Wesleyville and Greenhill Planning Study*, included as Appendix C, established the system need for replacement generation at the WES and GRH facilities by assessing the reliability, transmission support, and capacity functions currently provided by the facilities. The study concluded that approximately 15 MW of replacement generation at WES and 30 MW at GRH, together with supporting system upgrades, represents the recommended and least-cost solution for maintaining reliable service on the IIS.

A separate generation technology assessment evaluated CTGs, reciprocating internal combustion engines, and battery energy storage systems as alternatives for meeting the identified replacement-generation requirements. CTG technology was selected as it provides firm, sustained, dispatchable capacity and synchronous system support at a lower estimated lifecycle cost than the other viable alternatives. Newfoundland Power therefore proposes to replace the existing generation equipment at the WES facility with one nominal 15 MW CTG and to replace the existing generation equipment at the GRH facility with two nominal 15 MW CTGs. The projects include the associated fuel, auxiliary power, electrical, protection and control, building, civil, and substation work required to integrate the new units at the existing sites.

Class 3 cost estimates were developed for the proposed projects in accordance with the cost-estimate classification system of the Association for the Advancement of Cost Engineering ("AACE").[2] The estimates are based on preliminary engineering completed with support from a third-party engineering consultant and are supported by site-specific layouts, material take-offs, and vendor budget pricing. They include allowances for contingency, escalation, and financing and were developed to support regulatory review and approval. The total estimated cost of the proposed projects is $242.1 million, comprising $86.35 million for the WES scope and $155.74 million for the GRH scope.

The projects are planned over five years, primarily because current CTG procurement lead times are approximately three to four years. Engineering, environmental approvals and procurement would advance during the early years, followed by site preparation, construction, installation and commissioning.

The use of existing developed sites and the anticipated low-utilization operating profile are expected to limit incremental environmental effects relative to greenfield or continuously operated thermal generation. The projects will undergo the applicable environmental assessment, permitting and regulatory review processes. The projects will incorporate modern emissions-control and environmental-protection measures and will be designed to comply with applicable regulatory requirements. Based on the proposed unit configurations and anticipated operating profiles, WES is not expected to be subject to the Government of Canada Clean Electricity Regulations annual emissions limit, while GRH is expected to operate within the applicable annual limit.

Newfoundland Power has undertaken early engagement with municipal representatives, area Members of the House of Assembly, local employers, and other stakeholders in the Bonavista Bay north coast and Burin Peninsula regions. The engagement provided information on the

[2] AACE International publishes a Cost Estimate Classification System that categorizes estimates (e.g., Class 5 to Class 1) based on the level of project definition. The system defines typical estimating methodologies, expected accuracy ranges, and appropriate use of estimates at each stage of project development.

condition of the existing facilities, the need for replacement generation, the proposed project scope, and the reliability functions performed by generation at WES and GRH. Newfoundland Power received written expressions of support from municipal and business stakeholders in both regions. The Company will continue stakeholder engagement as the projects advance through environmental assessment, detailed engineering, procurement, and construction.

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Appendix A: Thermal Generation Condition Assessment
Appendix B: WES and GRH Thermal Facility Historical Capital Upgrades
Appendix C: Wesleyville & Greenhill Planning Study
Appendix D: Generation Technology Assessment
Appendix E: Cost Estimates
Appendix F: Stakeholder Engagement Letters of Support

1.0 INTRODUCTION

Newfoundland Power Inc. ("Newfoundland Power" or the "Company" or "NP") operates a fleet of six thermal generating facilities, consisting of four stationary generators and two mobile generators. These facilities provide (i) local reliability support to customers in rural areas, (ii) regional transmission system support, and (iii) overall system capacity on the Island Interconnected System ("IIS").

The generating equipment at two of the Company's thermal facilities has reached the end of its service life and requires replacement, together with renewal of associated facility infrastructure. These include Newfoundland Power's Wesleyville ("WES") and Greenhill ("GRH") facilities. The combustion turbine generators ("CTGs") at WES and GRH were originally installed in 1969 and 1975, respectively, and have remained in service since that time due to routine maintenance and periodic refurbishments when necessary. A recent condition assessment has determined that the WES and GRH facilities are in poor overall condition and have reached the end of their service lives due to their age, condition, and lack of vendor support. This creates increasing reliability risks and operational uncertainty.

To support the identification and evaluation of suitable alternatives to address the condition of the WES and GRH facilities, Newfoundland Power undertook a generation technology and alternatives assessment. The assessment considered feasible thermal and non-thermal replacement technologies capable of meeting the operational, reliability, and system-support requirements of the IIS. The assessment evaluated technology suitability, constructability, operating characteristics, and capital and operating costs for each alternative. The recommended facility refurbishment solution presented in this report is informed by the findings of this assessment.

The Company proposes coordinated five-year projects to replace the existing generating equipment and renew the associated infrastructure at WES and GRH. Current CTG delivery lead times are the principal driver of the proposed five-year project schedules. The first three years will focus on detailed engineering, procurement, and contract approvals, followed by installation and commissioning during the final two years.

For the purposes of this regulatory application and to comply with the provisional *Capital Budget Application Guidelines* ("Provisional Guidelines") issued by the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board"), the WES and GRH scopes have each been separated into two projects to reflect the scope of work required for the distinct thermal generation and substation asset classes. The WES scope is separated into the following capital projects: (i) *Wesleyville Thermal Generation Facility Refurbishment*; and (ii) *Wesleyville Substation Upgrades for Thermal Generation*. The GRH scope is separated into the following capital projects: (i) *Greenhill Thermal Generation Facility Refurbishment*; and (ii) *Greenhill Substation Upgrades for Thermal Generation*. References in this report to the proposed WES project or GRH project refer collectively to both the thermal generation and substation projects associated with the respective site.

2.0 BACKGROUND

This section provides background on the role of thermal generation on the IIS, the broader system planning context, and Newfoundland Power's existing thermal generation fleet.

2.1 Thermal Generation on the IIS

Electricity supply on the IIS is derived from a combination of on-island and off-island generation sources. On-island generation includes major hydroelectric facilities, such as Newfoundland and Labrador Hydro's ("Hydro" or "NLH") Bay d'Espoir ("BDE") Generating Station and Holyrood Thermal Generating Station ("Holyrood TGS"), along with other generation resources located throughout the IIS. Off-island supply is provided primarily through the Labrador Island Link (the "LIL") and Maritime Link high-voltage direct current interconnections. Generation dispatch on the IIS is conducted in accordance with Hydro's Operating Reserves Procedure which identifies the sequential order in which generation is dispatched on the IIS.[3]

Most of the electricity supplied on the IIS is generated from renewable resources, principally hydroelectric generation.[4] This is primarily from Hydro's hydroelectric facilities including BDE and Muskrat Falls and also includes Newfoundland Power's hydroelectric facilities in addition to renewable energy from third party hydroelectric and wind generation providers. In addition to renewable sources, the availability of thermal sources of generation remains a critical component of the IIS. Thermal generation provides operational flexibility, system support, and reliability on a system and local basis. Thermal generation is typically utilized when: (i) renewable sources of generation are not available or sufficient to carry all IIS load; (ii) during system contingencies such as transmission line outages; and (iii) to support planned events such as transmission line maintenance. The inherent operating characteristics of most thermal generation facilities enable fast response and controllability.[5]

Sources of thermal generation on the IIS include Hydro's Holyrood TGS, Holyrood Combustion Turbine ("Holyrood CT"), Hardwoods Combustion Turbine ("Hardwoods"), Holyrood Diesel generators, and Hydro's proposed Avalon Combustion Turbine ("Avalon CT") which are all located on the Avalon Peninsula.[6] Hydro's other thermal generation facilities located in Stephenville, Hawkes Bay, and St. Anthony support reliability in rural areas of the province and

[3] The overall IIS including generation, transmission, and distribution is operated jointly by Hydro and Newfoundland Power, with both utilities' systems fully interconnected and coordinated through joint planning and operations. Newfoundland Power's generation dispatch is managed between Hydro's Energy Control Centre ("ECC") and Newfoundland Power's System Control Center ("SCC") in accordance with Hydro's Operating Reserves Procedure (BA-P-012).

[4] In 2025, approximately 89% of the energy generated for use on the IIS was from renewable sources. The remaining 11% was from thermal sources of generation which was primarily associated with the Holyrood TGS.

[5] The Holyrood TGS is a base load thermal generating facility. It does not have fast response capability and is required to be loaded at a minimum generating threshold during the winter season to provide backup support for the IIS.

[6] Hydro is in the process of adding additional capacity to the IIS to help facilitate the retirement of Holyrood TGS since it is no longer a reliable source of generation. See the response to Request for Information PUB-NLH-001 in relation to Hydro's Additional Early Execution Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine, filed January 28, 2026.

also contribute towards the system capacity requirements on the IIS.[7,8] This is consistent with Newfoundland Power's six thermal generation facilities which are located throughout its service territory to support local reliability requirements and also to provide system capacity and transmission support on the IIS. Figure 2 shows the thermal generating units on the IIS.

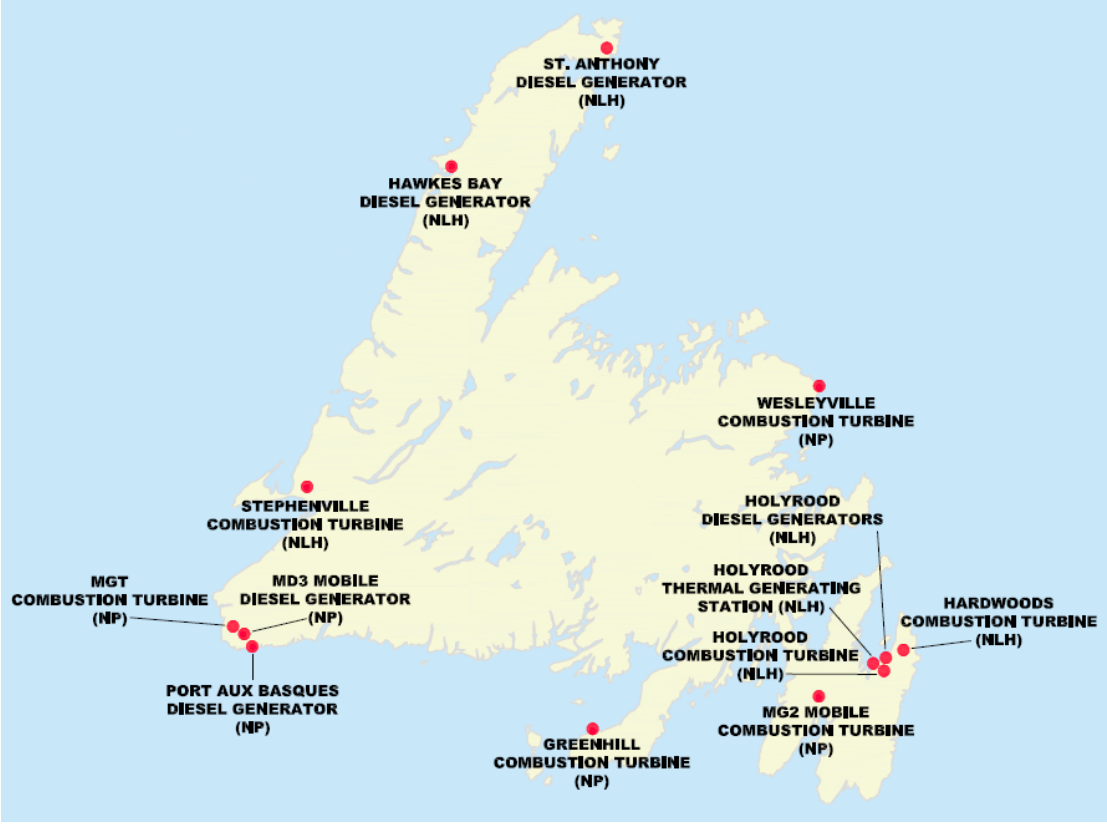


Figure 2 –Thermal Generation on the IIS

Thermal generation plays a critical role on the IIS by maintaining reliability during periods when renewable generation is unavailable or becomes constrained.[9] The importance of thermal generation was demonstrated during January 21 to 26, 2026, when the Bay d'Espoir hydroelectric facility was unavailable because of frazil ice and thermal resources were

7 Hydro continues to operate and maintain its St. Anthony and Hawkes Bay diesel generators on the Northern Peninsula. See Hydro's *2024 Resource Adequacy Plan, Appendix B: Planning Criteria and Study Methodology*, page 30 of 57, Table 4: Island Interconnected System Existing Thermal Generating Units (MW). These were utilized during the January 21-26, 2026 frazil ice event. See Hydro's April 30, 2026 report *Frazil Ice at Bay d'Espoir Hydroelectric Generating Station*, page 15, *Section 4.3.3 Standby Generation* and page 23, *Section 4.5.3 Standby Generation*.

8 The role of Hydro's Stephenville gas turbine to support local and regional reliability in the Stephenville area is explained in Hydro's June 15, 2026 report *Hardwoods and Stephenville Life Extension Condition Assessment.* See *Section 3.3 Stephenville Gas Turbine*, page 6, lines 11-17.

9 Examples of renewable generation shortages could include an outage to the Muskrat Falls hydroelectric generating station or Labrador Island Link transmission line, or generation shortages associated with other hydroelectric and wind generation facilities on the IIS.

dispatched to support system reliability.[10] During the event, Newfoundland Power's thermal generation supplied 215 MWh to support system reserves and reduce the risk of rotating outages for customers.[11]

The importance of Newfoundland Power's thermal generation assets has been recognized by the Board. In its Order approving the Company's thermal generation capital expenditures as part of the *2022 Capital Budget Application*, the Board stated:

> *"The Board notes that this project is a recurring annual project that provides for the replacement or refurbishment of critical structures and equipment as identified during annual inspections and maintenance activities as well as in-service failures that have to be addressed as they occur. These assets are important to the provision of reliable service to customers on the Island Interconnected system and need to be maintained and repaired as required to remain operable. The only alternative to continued maintenance and operation of these assets is to retire them which, in the Board's view, would not be in the best interest of customers."*[12]

2.2 Newfoundland Power's Thermal Generation Fleet

Newfoundland Power has six thermal generation facilities with a total generation capacity of 44.5 MW. This includes four CTG facilities and two diesel engine generators ("DEG"). Four of the thermal facilities are stationary, and the remaining two facilities are mobile trailer-mounted thermal generation units. The stationary facilities are located in WES, GRH, Grand Bay, and Port aux Basques. The two mobile thermal facilities are normally stationed in Whitbourne and Grand Bay and can be mobilized to respond to localized issues throughout the IIS.

Wesleyville Combustion Turbine Generator

The WES CTG was manufactured by Associated Electrical Industries and originally installed in the community of Salt Pond on the Burin Peninsula in 1969. In 2003, it was relocated to the Town of New-Wes-Valley on the north coast of Bonavista Bay. The CTG comprises a hot gas generator ("HGG"), power turbine ("PT"), electrical generator and auxiliaries such as pumps, heat exchangers, circuit breakers and controls. The WES CTG is currently derated from 14.7 MW to 8 MW due to high vibration in the gearbox and operation duration is limited as a result of PT bearing overheating.

Fuel for the WES CTG is supplied from two above-ground 75,000 litre tanks. A new powerhouse was constructed when the WES CTG was relocated in 2003.

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[10] On January 21, 2026, Hydro reported it had decided to shut down all units at the BDE generating facility for the first time in its history due to the presence of frazil ice, temporarily removing approximately 600 MW of hydroelectric capacity from the IIS during peak winter demand. At the same time, issues were experienced at the Holyrood TGS. This prompted a Power Warning on January 24, 2026, signaling customers to conserve electricity and prepare for rotating power outages. For additional information, see Hydro's report *Frazil Ice at Bay d'Espoir Hydroelectric Generating Station*, filed with the Board on April 30, 2026.

[11] In addition to dispatching Newfoundland Power's thermal generation, Hydro also requested Newfoundland Power's curtailable customers to curtail at four separate times during the January 21-22, 2026 period.

[12] See Reasons for Decision Order No. P.U. 36 (2021), page 13, lines 8-14.

Greenhill Combustion Turbine Generator

The GRH CTG was manufactured by Curtiss Wright Power Systems in 1975 and is located in the Town of Grand Bank on the Burin Peninsula. The GRH CTG comprises a HGG, PT, electrical generator and auxiliaries such as coolers, pumps, air compressors, switchgear and controls. The CTG package is located outside the main control building in a separate enclosure. The GRH CTG, originally rated at 25 MW, was derated to 20 MW in 1984 at the manufacturer's recommendation due to deformation and cracking of the PT casing. Fuel for the unit is supplied from three above-ground 100,000 litre tanks.

In addition, the GRH CTG is capable of operating as a synchronous condenser, providing reactive power support to help regulate system voltage.

Grand Bay (MGT) Combustion Turbine Generator

The MGT CTG is located at the Grand Bay Substation in the Town of Channel-Port aux Basques. This CTG, manufactured by Orenda, is rated at 6 MW and was commissioned in 1974. In 2018, it was retired from mobile service and was permanently stationed at Grand Bay Substation. The CTG is comprised of two trailers: (1) one trailer houses the HGG, PT and electrical generator; and (2) a second trailer houses the unit controls, switchgear, power transformer and auxiliary power unit.

Port aux Basques Diesel Generator

The Port aux Basques ("PAB") DEG is located adjacent to the Port aux Basques Substation in the Town of Channel-Port aux Basques. This 2.5 MW DEG was manufactured by General Motors and installed in 1969. Auxiliaries for the DEG include coolers, fuel storage, switchgear, and controls. The battery system, control panel and switchgear for the diesel generator are contained in an adjacent building. The DEG is supplied with diesel fuel from one 22,700 litre tank located outside the powerhouse.

MD3 Mobile Diesel Generator

The MD3 mobile DEG is normally located at the Grand Bay Substation in the Town of Channel-Port aux Basques. This 2.5 MW DEG was manufactured by Detroit Diesel – Allison and was commissioned in 2004. This unit consists of a single trailer that houses the engine, generator, unit controls, switchgear, and power transformer.

MG2 Mobile Combustion Turbine Generator

A 5.5 MW portable gas turbine system manufactured by OnPower Inc. was purchased in 2019 and is normally stationed in Whitbourne. The system is comprised of three trailers: (1) a gas turbine/generator trailer; (2) a control/substation trailer; and (3) an auxiliary power unit trailer. The gas turbine trailer contains the gas turbine engine, gearbox, and generator. The electrical output of the gas turbine trailer is routed to a control/substation trailer that contains switchgear, power transformer, and protection and controls. The auxiliary power unit is used to start the gas turbine and provide black-start capability.

3.0 CONDITION ASSESSMENTS

Condition assessments for the WES, GRH, MGT, and PAB facilities were completed by Stantec Consulting Ltd. ("Stantec") in 2026.[13] Stantec's report titled *Thermal Generation Fleet Review*, dated May 4, 2026 (the "condition assessment(s)"), is provided as Appendix A. The assessment concluded that the WES and GRH facilities are in the poorest overall condition within the Company's thermal generation fleet.

3.1 Wesleyville Thermal Generation Facility

The WES facility is located in the Town of New-Wes-Valley. The facility is connected to the IIS via 66 kV transmission lines 116L and 115L. The WES CTG was originally installed in Salt Pond/Burin in 1969 and was relocated to its present location in New-Wes-Valley in 2003.[14]

Figure 3 shows the location of the WES facility and the transmission system supplying the area.

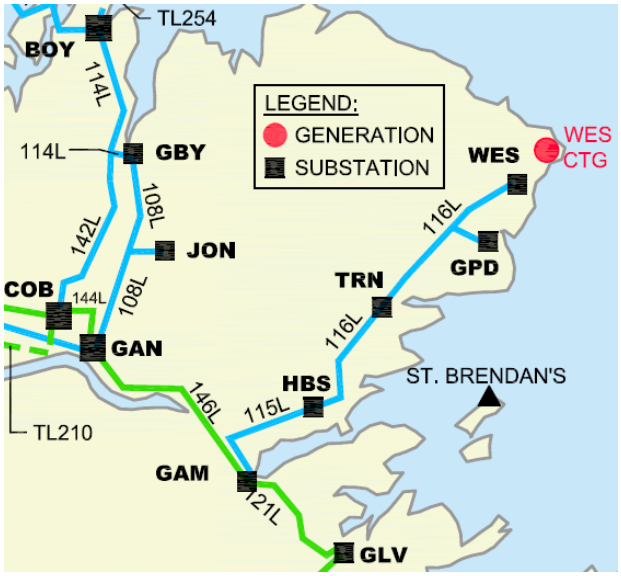


Figure 3 – WES Location

[13] Stantec is a consulting firm providing architecture, engineering, and environmental services to support project planning, design, and delivery.

[14] The Salt Pond gas turbine was relocated to Wesleyville to improve reliability for customers served by the Gambo–Wesleyville radial transmission system.

Figure 4 shows the WES facility.



Figure 4 – Wesleyville Thermal Generation Facility

The original WES CTG was purchased from Associated Electrical Industries ("AEI") in 1969 and is based on a Rolls Royce Avon HGG with an AEI PT driving an AEI generator. The electrical power generated is stepped up to 66 kV through a power transformer for delivery to the Company's transmission system via the on-site substation. The WES CTG was originally rated for 14.7 MW but is now derated to 8 MW as a result of long-term vibration issues associated with the PT gearbox.

In 2003, Newfoundland Power completed a project to relocate the WES CTG from Salt Pond, Burin to New-Wes-Valley. The relocation project included upgrades to the balance-of-plant systems, as well as a new building to house the CTG.

The existing facility includes a diesel fuel storage system with 150,000 litres of capacity. The WES CTG is fired on liquid No. 2 diesel fuel and does not utilize any form of emission controls for nitrogen oxide ("NOx") abatement. The Avon HGG originally installed at Salt Pond was replaced in 2005 with a refurbished unit of similar vintage. An auxiliary power unit ("APU") supports black-start functionality and starting of the CTG following system outages.

Appendix B titled *WES and GRH Thermal Facility Historical Capital Upgrades* summarizes capital upgrades undertaken at the WES facility from 2006 through 2025. During this period, approximately $3.2 million was invested in upgrades and refurbishment at the facility.

The WES Substation was constructed in 1974 and provides both local distribution service and transmission interconnection for the WES facility. The substation includes 66 kV, 12.5 kV, and

13.8 kV infrastructure and directly serves approximately 1,720 customers in the New-Wes-Valley area. While the substation remains operational, several substation assets, including the generation transformer manufactured in 1968 and relocated from Salt Pond in 2003, are of similar vintage to the existing generating unit.

Stantec's condition assessment determined that the WES facility is in poor overall condition and has reached the end of its service life. Critical components including the PT, gearbox, electrical generator, and exhaust system exhibit significant deterioration. The PT is experiencing elevated bearing temperatures that limit operating duration, as well as structural concerns, including vane cracking and rotor disc pitting. The gearbox continues to experience elevated vibration levels associated with long-term deterioration, which has resulted in the derating of the unit. The assessment also identified deterioration of the generator insulation system, obsolete instrumentation, protection and control equipment, and increasing challenges associated with limited vendor support. The exhaust volute and stack are also in poor condition.

Based on the condition of the facility, operational limitations, and lack of vendor support for critical equipment, Stantec concluded that the generation equipment at the WES facility has reached the end of its service life and recommended retirement of the facility within the next one to three years.

3.2 Greenhill Thermal Generation Facility

The GRH facility is located in the Town of Grand Bank on the Burin Peninsula. The facility is connected to the IIS via transmission lines 301L and 305L, which operate at 66 kV.

Figure 5 shows the location of the GRH facility and the transmission system supplying the area.

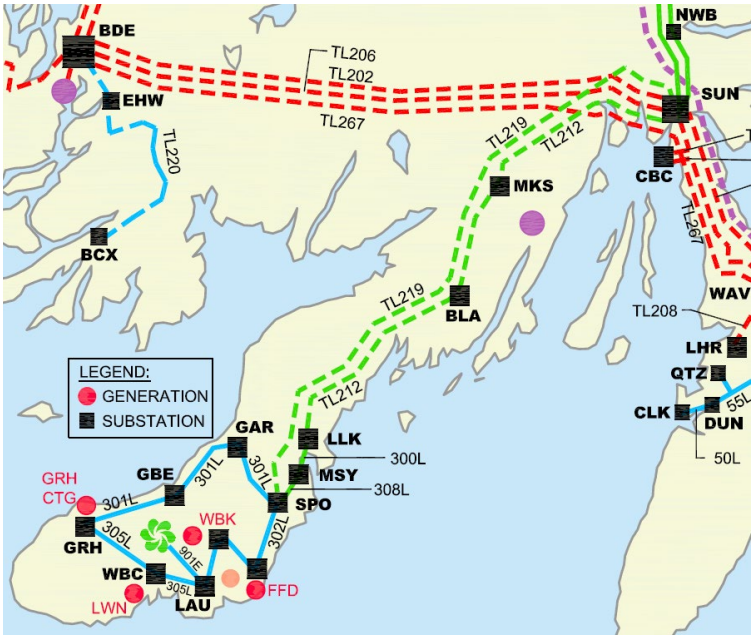


Figure 5 – GRH Location

Figure 6 shows the GRH CTG facility.



Figure 6 – Greenhill Thermal Generation Facility

The GRH CTG, manufactured by Curtiss Wright Power Systems ("CWPS"), was commissioned in 1975. The GRH CTG is based on a Rolls Royce Olympus C HGG with a CWPS PT driving a Brush Electric AC Generator. The electrical power generated is stepped up to 66 kV through a power transformer for delivery to the Company's transmission system via the on-site substation. The facility was originally rated for 25 MW but was derated in 1984 to 20 MW following manufacturer recommendations related to known issues associated with PT casing cracking. The derating was applied fleet-wide for all CWPS PT packaged units.

The existing GRH facility includes a diesel fuel storage system with 300,000 litres of capacity. The GRH CTG is fired on liquid No. 2 diesel fuel and does not utilize any form of emission controls for NOx abatement. An APU supports black-start functionality and starting of the CTG following system outages. The CTG is also capable of operating as a synchronous condenser to provide reactive power support and assist in the regulation of system voltage.

Appendix B titled *WES and GRH Thermal Facility Historical Capital Upgrades* summarizes capital upgrades undertaken at the GRH facility from 2006 through 2025. During this period, approximately $2.0 million was invested in upgrades and refurbishment at the facility.

The GRH Substation was constructed in 1977 and provides both local distribution service and transmission interconnection for the GRH CTG. The substation includes 66 kV, 12.5 kV, and 13.8 kV infrastructure and directly serves approximately 2,300 customers in the Grand Bank area. While the substation remains operational, several substation assets, including the generation transformer manufactured in 1975, are of similar vintage to the existing generating unit.

Stantec's condition assessment determined that the GRH facility is in poor overall condition and has reached the end of its service life. Critical components including the PT, electrical generator, fuel system, buildings, electrical equipment, and protection and control systems exhibit significant deterioration. The HGG is no longer supported by the original equipment manufacturer ("OEM"), and parts availability is limited to third-party vendors. The PT has experienced casing and shroud cracking, which has resulted in the permanent derating of the unit and continues to present ongoing reliability concerns. The generator's rotor retaining rings are also susceptible to stress-corrosion cracking, and the excitation system is obsolete. In addition, the fuel supply piping is in poor condition. Much of the original electric infrastructure is outdated, no longer meets modern safety standards, and is approaching the end of its service life. Furthermore, the facility's control and instrumentation systems, although partially upgraded, rely on obsolete human-machine interfaces ("HMI") components. The physical condition of the GRH facility buildings reflects the facility's advancing age, exhibiting widespread corrosion, structural deterioration, and inadequate protection from environmental elements.

Based on the condition of the facility, operational limitations, and lack of vendor support for critical equipment, Stantec concluded that the GRH facility has reached the end of its service life and recommended retirement of the facility within the next one to three years.

4.0 WESLEYVILLE AND GREENHILL OPERATIONS

The WES and GRH facilities are important sources of firm, dispatchable capacity on the IIS. These facilities are dispatched by Newfoundland Power for local reliability requirements and are also dispatched at the request of Hydro to address planned and unplanned events on the IIS.

Table 1 summarizes the WES and GRH facilities' historical operating use.[15]

Table 1
WES and GRH Historical Operating Data
(2006-2025)

	WES		GRH	
Reason for Dispatch	# of Events	Average Duration (hours)	# of Events	Average Duration (hours)
NLH Request for System Support (Unplanned)	58	2.9	114	3.7
NLH Request for Local Support (Unplanned)	0	0	2	6.8
NLH Request for Local Support (Planned)	1	1.7	29	3.3
NP Local Support (Unplanned)	6	8.4	0	0
NP Local Support (Planned)	27	15.2	5	0.8

The operating record shows that WES and GRH have been dispatched for planned and unplanned events, for both local and system support, and for operating periods ranging from less than one hour to more than 15 hours on average, depending on the event category. Replacement resources must therefore be capable of starting reliably when dispatched and sustaining output for events of varying duration.

5.0 WESLEYVILLE AND GREENHILL PLANNING STUDY

Newfoundland Power completed the *2027 Wesleyville and Greenhill Planning Study*, dated October 2026 (the "Planning Study"), to determine the long-term system requirements associated with retirement of the existing WES and GRH facilities. The Planning Study included input from Hydro and was completed within the context of the broader IIS planning activities.

The Planning Study is provided as Appendix C and forms the system planning basis for the proposed projects.

The Planning Study assessed the contribution of generation at WES and GRH to local reliability, transmission system performance, and firm, dispatchable capacity on the IIS. It also evaluated the system investments that would be required if the existing units were retired without future generation at these locations.

The Planning Study determined that the recommended planning solution includes approximately 15 MW of firm, dispatchable generation at WES and approximately 30 MW at GRH, together with the supporting Hydro system upgrades identified in the Planning Study. This solution maintains local reliability support, addresses identified transmission requirements, and provides firm capacity on the IIS.

[15] The operating data shown excludes monthly testing and troubleshooting activities.

The Planning Study also determined that this solution has the lowest net present value of the viable system planning alternatives evaluated, including the sensitivity cases examined in the study. Detailed analysis is provided in the Planning Study.

6.0 ASSESSMENT OF ALTERNATIVES

Condition assessments completed for the WES and GRH facilities conclude that both CTG units have reached the end of their service lives and should be retired due to poor condition, operational limitations, and lack of vendor support. The condition assessments establish that continued long-term reliance on the existing WES and GRH CTGs is not sustainable.

The WES and GRH facilities provide critical support to the transmission system, contribute firm, dispatchable capacity to the IIS, and support local reliability. The Planning Study demonstrates that the loss of these facilities gives rise to transmission planning violations, reduces system capacity, and diminishes local reliability. Replacement capacity capable of providing sustained output and system support is required to maintain system reliability and compliance with planning criteria.

In response to these findings, Newfoundland Power undertook an assessment of alternatives to address both the need to retire the existing assets and the associated system requirements. As part of this assessment, Newfoundland Power retained Sargent & Lundy ("S&L") to evaluate a range of technically feasible replacement options capable of providing firm, dispatchable capacity and associated system support.[16] S&L's assessment considered commercially available generation and energy storage technologies within the relevant capacity range and evaluated their ability to replace the functional role of the existing CTG units. The report titled *Generation Technology Assessment*, dated September 10, 2026 (the "S&L Report"), is provided as Appendix D. In the S&L Report, S&L considered the following alternatives for providing alternative capacity and associated system support: (i) replacement with CTGs; (ii) replacement with reciprocating internal combustion engines ("RICE"); and (iii) replacement with battery energy storage systems ("BESS"). Newfoundland Power also considered continued operation of the existing units, and retirement without replacement generation at the existing sites.

Each alternative was evaluated with respect to its ability to meet system requirements, including the provision of firm capacity, voltage support, contingency response capability, operational flexibility, and compatibility with the existing 138 kV transmission network supplying Central Newfoundland. Constructability, maintainability, and long-term suitability were also considered where relevant.

Association for the Advancement of Cost Engineering ("AACE") Class 4/5 cost estimates were prepared for each alternative using overnight cost estimates.[17,18] Costs were developed using a

[16] Sargent & Lundy is an engineering consulting firm with experience in the planning, design, construction, and implementation of power and energy infrastructure projects.

[17] AACE International publishes a Cost Estimate Classification System that categorizes estimates (e.g., Class 5 to Class 1) based on the level of project definition. The system defines typical estimating methodologies, expected accuracy ranges, and appropriate use of estimates at each stage of project development.

[18] Overnight cost estimates assume that the project is built "overnight" and is a common way to present costs in the energy industry as they allow for projects with different construction timelines to be compared on the same basis.

combination of budgetary estimates provided by equipment vendors and parametric allowances for items such as contractor direct, contractor indirect and owner's costs.[19]

For each technology alternative, S&L developed overnight capital cost estimates, which are presented as a capital cost ($/kW), as well as an annualized capital cost ($/kW-yr).[20,21] Fixed operations and maintenance ("O&M") costs, variable O&M costs, and sustaining capital costs are also included. Fixed O&M costs are incurred regardless of operating hours, while variable O&M costs are associated with unit operation. Sustaining capital costs represent the periodic capital expenditures required throughout the service life of the facility, including minor maintenance activities and major equipment overhauls for thermal generation technologies, and battery augmentation for the BESS alternative.

The assessment of alternatives is intended to inform the selection of technically suitable replacement solutions that maintain system reliability and planning compliance. The following sections summarize the assessment findings. Refer to the S&L Report, included as Appendix D, for additional details.

6.1 Alternative 1 - Replace with Combustion Turbines

CTGs are a well established and widely deployed technology for providing firm, dispatchable capacity in utility power systems. As identified in the S&L Report, CTGs are capable of providing the full range of operational and reliability services required to maintain system reliability and planning compliance, as outlined above, including firm dispatchable capacity, contingency response capability, and sustained operation during prolonged transmission outages and emergency conditions. CTGs are capable of rapid start and ramping and can provide sustained output over extended durations, allowing them to mitigate planning violations arising from prolonged transmission or transformer outages.

In addition to capacity, CTGs provide important system support functions, including voltage regulation, reactive power capability, inertia, and fault-current contribution. In the context of the IIS, these characteristics provide benefits beyond energy production by supporting system strength and voltage stability in a manner comparable to synchronous condensers, while also providing firm, dispatchable generating capacity when required.

Newfoundland Power has longstanding operational experience with CTG technology through the existing WES and GRH facilities, as well as the MGT and MG2 CTGs. While CTGs are more complex to operate and maintain than diesel generating units, Newfoundland Power has experienced personnel qualified to operate and maintain this technology, and specialized vendor support is readily available.

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19 Based on S&L's experience with similar projects tailored to the specific WES and GRH sites for the various technologies.

20 The overnight capital cost represents the estimated construction cost of the generating facility, excluding escalation and financing fees. The cost estimates also exclude substation related costs as they were expected to be relatively comparable across the different technology options considered and would not materially impact the comparative technology evaluation.

21 Annualized capital costs provide a simplified means of comparing technologies with different service lives by expressing overnight capital costs on an annual basis.

The assessment of alternatives also identified advantages associated with maintenance, servicing, and long-term asset management. Relative to equivalent reciprocating engine installations, CTG packages are more compact and lighter, facilitating transportation, installation, and component replacement. The major turbine and generator components can be removed and refurbished as discrete assemblies, allowing major repairs and overhaul activities to be completed off-site, reducing outage durations and on-site construction requirements. In the event of a major failure, CTG technology also provides flexibility to substitute components or replacement modules while repairs are completed, reducing the risk of prolonged capacity unavailability.

Modern CTGs also provide flexibility with respect to fuel selection. While diesel fuel represents the most practical and reliable option given existing infrastructure and operating requirements, commercially available CTGs are available in configurations capable of utilizing alternative fuel sources or accommodating future fuel conversions. This flexibility provides potential long-term optionality should fuel supply conditions or technology requirements evolve over the life of the asset.

The assessment noted that CTGs are more complex to operate and maintain than diesel engine technologies and generally have lower thermal efficiencies. CTGs also have more limited load pickup capability during startup and may require additional operational considerations under certain system conditions. However, given the anticipated operating profile of the facilities in the future and the need for firm, dispatchable capacity and system support, these considerations do not outweigh the advantages of CTG technology for the WES and GRH applications.

Table 2 summarizes the cost estimates for the CTG alternative.

Table 2
CTG Cost Estimate

Site	Capital Cost ($/kW)	Capital Cost ($/kW-yr)[22]	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Sustaining Capital Cost ($/kW-yr)
Wesleyville	5,013	143	26.5	0.5	14.1
Greenhill	4,151	119	21.5	0.5	14.1

Based on these considerations, CTG technology is well suited to the identified application and is capable of providing the firm, dispatchable capacity and synchronous system support required to replace the existing WES and GRH CTGs. The technology provides the combination of firm capacity, contingency response capability, synchronous system support, and operational flexibility required for this application.

[22] Annualized capital cost for the CTG alternative is based on a service life of 35 years.

6.2 Alternative 2 - Replace with Reciprocating Internal Combustion Engines

RICE technology is widely deployed in utility systems for emergency generation, backup power, and stationary generation applications due to its high reliability and strong load pickup capability. As identified in the S&L assessment, RICE units are capable of providing firm, dispatchable capacity, rapid response capability, and sustained operation during contingency events. Diesel-fueled RICE units are characterized by their rugged design, operational flexibility, and strong load acceptance characteristics, allowing for near-instantaneous acceptance of large load blocks with minimal frequency or voltage disturbance. Newfoundland Power also has experience operating diesel engine generating units, and the technical resources required to operate and maintain such equipment are well established within the province.

When coupled to synchronous generators, RICE units can also provide important system support functions, including inertia, reactive power support, and fault-current contribution. These characteristics enable RICE technology to provide many of the reliability and voltage support benefits associated with synchronous generation. In addition, RICE technology offers some degree of fuel flexibility, with commercially available units capable of operating on diesel fuel and, in certain configurations, accommodating alternative liquid or gaseous fuels.

However, there are several limitations relative to CTG technology. While commercially available RICE units are capable of providing the required capacity at both the WES and GRH facilities, the size and weight can introduce transportation, installation, and site integration challenges. As a result, achieving the required capacity may require multiple units operating in parallel at both sites, increasing site footprint, operational complexity, control system requirements, and protection coordination requirements. Also, while synchronous condenser functionality is technically feasible, RICE units do not have an established history of operating as synchronous condensers.

The assessment also noted that RICE units are generally larger and heavier than equivalently sized CTGs, requiring shipment and assembly of major components on site. Major refurbishment, overhaul, or equipment replacement activities are typically completed on-site and may require extended outages and specialized lifting equipment. Unlike CTGs, the lack of interchangeability of major equipment assemblies limits the ability to rapidly replace failed components or generating units, increasing the potential duration of capacity unavailability following major equipment failures. Although RICE units generally achieve higher thermal efficiencies than CTGs, this advantage is less significant in applications characterized by limited annual operating hours.

Table 3 summarizes the cost estimates for the RICE alternative.

Table 3
RICE Cost Estimate

Site	Capital Cost ($/kW)	Capital Cost ($/kW-yr)[23]	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Sustaining Capital Cost ($/kW-yr)
Wesleyville	5,505	157	23	5.5	8.4
Greenhill	4,903	140	23	5.5	7.2

The RICE alternative has higher estimated capital costs than the CTG alternative. Fixed O&M costs are generally comparable between the two technologies. Variable O&M costs are higher for RICE units, while sustaining capital costs are lower for RICE units. Overall, these factors reduce the overall cost competitiveness of the RICE alternative.

Based on these considerations, RICE technology is technically capable of meeting the identified system requirements. However, increased costs, site integration, constructability, and operational complexity reduce its suitability relative to CTG technology for refurbishment of the existing WES and GRH facilities.

6.3 Alternative 3 - Replace with Battery Energy Storage Systems

BESS represents an increasingly deployed technology capable of providing rapid response and a range of ancillary services, including short-duration capacity, frequency response, and voltage regulation. These characteristics make BESS well suited to applications requiring fast response and operational flexibility. As noted in the S&L assessment, BESS can provide important grid support functions, including voltage support and frequency response, particularly when configured with grid-forming inverter technology.

While BESS can provide fast reactive power support and contribute to voltage regulation, it is constrained by its energy-limited nature. The contingency scenarios identified in the Planning Study include prolonged outages and extended peak load conditions that require sustained output beyond the typical four-hour duration associated with most utility-scale BESS installations. As a result, BESS is unable to provide the firm, dispatchable capacity required to fully replace the functional contribution of the existing thermal generating units.

BESS does not provide the same level of system inertia or fault-current contribution as rotating synchronous equipment. While inverter-based resources can provide synthetic inertia and reactive power control, they do not fully replicate the synchronous system support characteristics provided by CTGs or RICEs. In addition, following discharge during a contingency event, a BESS resource requires recharging before it can provide support again. During prolonged events, recharge opportunities may be constrained and the BESS effectively becomes an additional system load while recharging.

[23] Annualized capital cost for the RICE alternative is based on a service life of 35 years.

Table 4 summarizes the cost estimates for the BESS alternative.

Table 4
BESS Cost Estimate

Site	Capital Cost ($/kW)	Capital Cost ($/kW-yr)[24]	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Sustaining Capital Cost ($/kW-yr)
Wesleyville	3,113	156	45	0	24.7
Greenhill	2,709	135	43	0	24.7

While BESS has a lower initial capital cost than thermal generation alternatives, its annualized cost is higher due to its shorter service life. Fixed O&M costs and sustaining capital costs are also higher than the thermal generation alternatives. The assessment was based on a four-hour storage duration and noted that longer-duration storage may be more appropriate for this application. However, increasing storage duration results in a significant increase in project cost while still not providing the same level of firm, dispatchable capacity as thermal generation technologies.

Based on these considerations, BESS represents an effective complementary technology for short-duration support and operational flexibility. However, BESS alone is not capable of meeting the firm, dispatchable capacity requirements identified for replacement of the WES and GRH generation capacity. Accordingly, while BESS may form part of a broader portfolio of system improvements, it does not independently satisfy the firm, dispatchable capacity and reliability requirements identified for this application.

6.4 Alternative 4 - Maintain Existing Units

Another alternative considered was the continued operation of the existing WES and GRH CTGs through ongoing maintenance and selective refurbishment. This option was evaluated based on detailed condition assessments, which examined the technical feasibility of extending the service life of each facility given their age, condition, and operational role.

Condition assessments concluded that both the GRH and WES CTGs have reached the end of their service lives and recommended retirement of the units within the next one to three years. In addition to deteriorated CTGs, the assessments identified advanced deterioration affecting a range of critical components, including elements of the HGG, PT, electrical generator, auxiliary systems, and facility infrastructure.

In addition, key equipment is either obsolete or no longer supported by OEMs, with parts availability increasingly reliant on third-party vendors. This introduces additional uncertainty with respect to long-term maintainability and system availability. CTGs in both facilities have already been permanently derated due to mechanical limitations. As a result, continued operation would carry elevated technical and reliability risk.

[24] Annualized capital cost for the BESS alternative is based on a service life of 20 years.

From a system reliability perspective, maintaining the existing CTG units does not provide a durable solution to the planning requirements identified for Central Newfoundland. Increasing maintenance needs, elevated outage risk, and reduced confidence in the long-term availability of the units during peak and contingency conditions limit their ability to reliably provide firm capacity and voltage support.

The condition assessments indicate that the challenges associated with WES and GRH are not isolated to a small number of components that could be addressed through targeted refurbishment. Rather, deterioration, obsolescence, and vendor support challenges exist across multiple major facility systems and supporting infrastructure. As a result, maintaining the facilities would require significant ongoing investment across numerous systems while continuing to rely on aging assets that have already reached the end of their service lives.

On this basis, the option to maintain and continue operating the existing WES and GRH CTG units was determined not to be a feasible long-term alternative for providing the firm capacity, system support, and reliability required for the Central Newfoundland transmission system.

6.5 Alternative 5 - Retire WES and GRH Facilities

Retirement of the existing WES and GRH facilities is required because of their overall condition. The option of retiring the existing CTG units without installing replacement generation at WES and GRH was assessed in the Planning Study. That option would require alternative capacity, transmission, reactive power, and local reliability investments to replace the functions currently provided at the two locations. The Planning Study determined that this system alternative is technically feasible but is not the least-cost solution. An assessment of the alternative to retire the existing WES and GRH facilities is provided in the Planning Study.

6.6 Assessment of Alternatives

The Planning Study establishes the need for approximately 15 MW of firm, dispatchable capacity at WES and approximately 30 MW of firm, dispatchable capacity at GRH.

CTG and RICE technologies were both identified as technically capable of providing firm, dispatchable generation and synchronous system support. BESS was not identified as a stand-alone replacement as it does not satisfy the requirement for sustained output during extended contingency conditions at the WES and GRH facilities. Continued operation of the existing CTGs was also rejected based on the findings of the condition assessments, which recommend their retirement.

CTG technology is recommended because it provides the required firm, dispatchable capacity and synchronous support with lower estimated lifecycle costs and less site-integration and implementation complexity than the RICE alternative. Detailed technology characteristics and estimates are provided in Appendix D.

7.0 RISK ANALYSIS

The Board’s Provisional Guidelines require Newfoundland Power to complete a risk assessment in relation to projects and programs classified as Renewal. Newfoundland Power completed a

risk assessment for the WES and GRH projects in accordance with the Risk Assessment methodology outlined in the *2027 Capital Budget Application*.[25] This includes assigning a value, in the range of 1-5, based on probability and consequence. Probability values are based on the likelihood of occurrence being Rare (1) to Near Certain (5). Consequence values are based on the significance of outcomes and range from Negligible (1) to Critical (5). Probability and consequence values are multiplied together to establish an overall risk score. The resulting risk score ranges from 1 to 25, with 25 representing the highest possible risk rating.

The risk event assessed is the risk associated with not proceeding with the identified WES and GRH projects, considering the probability and consequence of the loss of the local reliability, transmission-support, and firm-capacity functions currently provided by WES and GRH before replacement generation is placed in service.

7.1 Probability

Probability refers to the likelihood that an event will occur if the identified projects did not proceed. This section considers whether, absent the proposed WES and GRH projects, the WES and GRH facilities are likely to become incapable of performing their functions on the IIS. The condition assessments completed by Stantec in 2026 provide a comprehensive review of the WES and GRH facilities and their ability to continue to operate reliably in the future.

Stantec determined that both the WES and GRH facilities are in poor overall condition. Based on the condition of the WES and GRH facilities, operational limitations, and lack of vendor support for critical equipment, Stantec concluded that the WES and GRH facilities have reached the end of their service lives and recommended retirement of the facilities within the next one to three years.

The probability that the WES and GRH facilities will become unable to provide their required functions is therefore assessed as Near Certain (5).

7.2 Consequence

Consequence refers to the potential impacts associated with not proceeding with the identified projects, considering the effects of losing the functions currently provided by the WES and GRH facilities before the proposed replacement projects are placed in service.

The resulting consequences would include loss of local generation support, reduced ability to respond to identified transmission contingencies, and loss of firm, dispatchable capacity on the IIS. The technical basis for these consequences is documented in the Planning Study provided in Appendix C.

These consequences could affect reliable service in the immediate areas surrounding the facilities as well as in Central Newfoundland and the overall IIS. Accordingly, under the risk methodology described above, the consequence is assessed as Critical (5).

[25] See Newfoundland Power's *2027 Capital Budget Application*, Schedule B, pages iii to iv.

7.3 Risk Assessment Summary

Table 5 summarizes the risk assessment for the WES and GRH CTG projects.

Table 5
WES and GRH CTG Projects
Risk Assessment Summary

Consequence	Probability	Risk
Critical (5)	Near Certain (5)	High (25)

Based on this assessment, not proceeding with the WES and GRH refurbishments would pose a High (25) risk to the delivery of reliable service to customers.

8.0 PROPOSED PROJECTS

8.1 Wesleyville Thermal Generation Refurbishment Project

The proposed project involves the refurbishment of the WES facility, including the replacement of the CTG.[26] The proposed project will replace the existing generating equipment and provide approximately 15 MW of firm, dispatchable capacity, together with synchronous system support.

Project development will leverage the existing site and infrastructure where practical, while incorporating modern generating technology designed to meet current safety, reliability, and environmental requirements. The proposed solution is intended to provide long-term reliability support while maintaining flexibility to adapt to evolving long-term system needs.

The project scope is defined in the following sections.

Combustion Turbine

The proposed project includes the installation of a nominal 15 MW CTG generating unit configured to provide firm, dispatchable capacity and system support. The CTG will be coupled to an electrical generator with an output voltage of 13.8 kV. The unit will be capable of rapid start and sustained operation.

The proposed CTG may be deployed either as a modular, pre-assembled package or within a traditional building-based configuration, depending on final equipment selection and procurement considerations. Both approaches are capable of meeting the functional requirements identified for the project, including the provision of firm, dispatchable capacity and synchronous system support. A modular configuration would offer advantages associated with factory assembly and testing, reduced on-site construction complexity, and potentially shorter installation durations. A traditional building-based installation may provide additional

[26] The WES scope is separated into the following capital projects: (i) *Wesleyville Thermal Generation Facility Refurbishment*; and (ii) *Wesleyville Substation Upgrades for Thermal Generation*.

flexibility with respect to equipment arrangement and long-term facility integration. The final configuration will be determined during detailed engineering and procurement.

The CTG will be configured for dual-fuel operation, with diesel fuel as the primary fuel consistent with current fuel availability and infrastructure. The unit will also be designed with the capability to operate on alternative fuels in the future, subject to fuel availability and required system modifications, providing longer-term flexibility as energy supply options evolve. The combustion system will employ technology to minimize nitrogen oxide (NO_x) emissions.

In addition to energy and capacity production, the proposed CTG installation will include the capability to operate in synchronous condenser mode, providing reactive power and voltage regulation without operating the combustion components.

Fuel System

The proposed project includes replacement of the existing fuel storage and forwarding systems to support reliable operation of the new CTG.

The proposed scope includes the installation of new fuel storage tanks with fuel storage capacity to support approximately 48 hours of continuous operation at rated load, with space to expand if required in the future. Tanks will be designed to ensure continued environmental protection, leak detection capability, and compliance with current regulatory standards. In addition, the tanks will be placed in a bermed containment area.

The proposed fuel system scope will permit connection of portable fuel conditioning equipment to support long-term fuel quality management. Given the operating profile of the CTG, fuel may be stored on site for extended periods when the unit is not in operation. The fuel conditioning equipment will be used to remove water, particulates, and other contaminants from stored diesel fuel, helping to maintain fuel quality, reduce the risk of fuel-related operational issues, and support reliable starting and operation when the CTG is dispatched. Integration of fuel conditioning equipment supports long-term reliability and aligns with good utility practice for standby generation facilities.

A new fuel forwarding system, including pumps, controls, piping and associated equipment will be installed. A new fuel system building or enclosure will be provided as required to house fuel forwarding equipment and controls.

Auxiliary Power Unit

An APU will be installed to support black-start functionality and reliable starting of the CTG following system outages. Black-start capability is required to energize auxiliary systems, initiate CTG startup, and restore local generation in the absence of an external power supply.

Based on vendor requirements, the new APU will be sized at approximately 1.5 MW and will be capable of supplying sufficient power to support turbine startup, auxiliary loads, and associated control and protection systems.

As part of the project scope, the existing APU and associated propane fuel storage system will be removed. The new APU will be fueled from a base mounted fuel tank.

Yard Expansion

The proposed project includes expansion of the existing site yard to accommodate installation of the CTG generating unit and associated infrastructure. A small parcel of Crown land adjacent to the existing facility will be acquired to support the proposed expansion, allowing the required site development to occur adjacent to the existing facility.

Yard expansion will be undertaken to provide adequate space for placement and installation of the CTG unit, fuel storage tanks, auxiliary equipment, and associated access and safety clearances. This work will include site grading, fencing modifications, foundations, and adjustments to access roads and laydown areas, as necessary to support construction, operation, and maintenance of the new equipment.

Building

The existing building is in fair overall condition. The existing building will be retained and will accommodate protection, control, and communications equipment associated with both the new CTG installation and the substation equipment. Existing ancillary spaces, including the kitchen, washroom, and storage areas, will remain in service. Retaining and reusing the existing building minimizes the need for new construction and leverages existing infrastructure already integrated into the site.

Building modifications will be undertaken as required to facilitate removal of the existing CTG equipment, including associated intake and exhaust systems, and to address known roof leakage issues. The existing CTG and fuel pump area will be reconfigured as required to accommodate the selected CTG configuration and associated auxiliary equipment, including electrical, mechanical, and storage spaces.

Switchgear

New 13.8 kV switchgear will be installed to support safe, reliable operation and isolation of the CTG. The switchgear will be designed to incorporate modern protection and control features, including arc-flash mitigation measures, to enhance personnel safety and improve operational flexibility.

Currently, the generating unit at the site is connected directly to a breaker located in the substation yard, with no dedicated generator switchgear installed within the facility. This complicates routine and emergency operations as it requires coordination with substation personnel for isolation and control. Installation of 13.8 kV switchgear within the generator facility will address these limitations by enabling local control and isolation of the generation facility, simplifying startup, shutdown, and maintenance activities, and improving response times during abnormal conditions.

Protection & Control Systems

Existing protection and control systems will be replaced with new, modern systems consistent with current utility standards and best practices. Control and monitoring systems associated with the new CTG will be provided as part of the vendor's scope and will include modern turbine controls, condition monitoring, and integrated Human-Machine Interfaces ("HMIs"). These systems will support reliable operation, diagnostics, and maintenance.

The upgraded protection and control architecture will improve reliability, reduce dependency on obsolete components, and enhance operational visibility and control.

Substation

The proposed project includes modifications and upgrades to substation components to support integration and reliable operation of the new CTG.

To support full output from the unit, additional cooling fans will be installed on the existing power transformer to increase its thermal capacity and ensure it can operate within allowable limits under all operating conditions. The existing generation transformer will remain in service based on its present condition, loading capability following the proposed cooling upgrades, and its treatment under the Company's broader substation power transformer strategy. Its condition and performance will continue to be monitored through the Company's established inspection, testing, and asset-management practices.

Existing obsolete protection and control equipment within the substation will be upgraded or replaced as required to ensure compatibility with the new generation facility and to align with current protection standards. These upgrades will support proper coordination between generation, transformer, and distribution protection systems.

New motorized air-break switches will be installed to provide enhanced isolation capability for both the generation transformer and the distribution transformer. These switches will enhance the protection scheme and allow for safe and efficient isolation of equipment for maintenance and emergency operations.

A 1.5 MVA station service transformer will be installed to facilitate the CTG starting under normal conditions and to provide site power.

The project scope also includes installation of a new spill containment foundation for the power transformer. The spill containment system is required to protect against environmental damage in the event of an oil spill and to mitigate safety risks associated with transformer oil releases.

8.2 Greenhill Thermal Generation Refurbishment Project

The proposed project involves the refurbishment of the GRH facility, including the replacement of the CTG.[27] The proposed project will replace the existing generating equipment and provide

[27] The GRH scope is separated into the following capital projects: (i) *Greenhill Thermal Generation Facility Refurbishment*; and (ii) *Greenhill Substation Upgrades for Thermal Generation*.

approximately 30 MW of firm, dispatchable capacity through two nominal 15 MW CTGs, together with synchronous system support.

Project development will leverage the existing site and infrastructure where practical, while incorporating modern generating technology designed to meet current safety, reliability, and environmental requirements. The proposed solution is intended to provide long-term reliability support while maintaining flexibility to adapt to evolving long-term system needs. The project scope is defined in the following sections.

Combustion Turbine

The proposed project includes the installation of two nominal 15 MW CTGs operated in parallel to provide approximately 30 MW of firm, dispatchable capacity and system support. Each CTG will be coupled to an electrical generator with an output voltage of 13.8 kV. The units will be configured to operate as an integrated generating facility and will be capable of rapid start and sustained operation.

The proposed CTGs may be deployed either as a modular, pre-assembled package or within a traditional building-based configuration, depending on final equipment selection and procurement considerations. Both approaches are capable of meeting the functional requirements identified for the project, including the provision of firm, dispatchable capacity and synchronous system support. A modular configuration would offer advantages associated with factory assembly and testing, reduced on-site construction complexity, and potentially shorter installation durations. A traditional building-based installation may provide additional flexibility with respect to equipment arrangement and long-term facility integration. The final configuration will be determined during detailed engineering and procurement.

Each CTG will be configured for dual-fuel operation, with diesel fuel as the primary fuel consistent with current fuel availability and infrastructure. The units will also be designed with the capability to operate on alternative fuels in the future, subject to fuel availability and required system modifications, providing longer-term flexibility as energy supply options evolve. The combustion system will employ technology to minimize nitrogen oxide (NO_x) emissions.

In addition to energy and capacity production, the proposed CTG installation will include the capability to operate in synchronous condenser mode, providing reactive power and voltage regulation without operating the combustion components.

Fuel System

The proposed project includes replacement of the existing fuel-storage and fuel-forwarding systems to support reliable operation of the new CTGs.

The proposed scope includes the installation of new diesel fuel storage tanks with fuel storage capacity to support approximately 48 hours of continuous operation at rated load for the combined generating facility, with space to expand if required in the future. Tanks will be designed to ensure continued environmental protection, leak detection capability, and compliance with current regulatory standards. In addition, the tanks will be placed in a bermed containment area.

The proposed fuel system will permit connection of portable fuel conditioning equipment. Given the operating profile of the CTGs, fuel may be stored on site for extended periods when units are not in operation. The fuel conditioning equipment will be used to remove water, particulates, and other contaminants from stored diesel fuel, helping to maintain fuel quality, reduce the risk of fuel-related operational issues, and support reliable starting and operation when the units are dispatched. Integration of fuel conditioning equipment supports long-term reliability and aligns with good utility practice for standby generation facilities. The fuel conditioning equipment is envisioned to be mounted on a trailer to allow it to be used at multiple thermal facility locations on the Newfoundland Power system.

New fuel piping, pumps, valves, controls, and ancillary components will be provided to ensure reliable operation, regulatory compliance, and full integration with the new generating units. A new fuel system building or enclosure will be provided as required to house forwarding equipment and controls.

Auxiliary Power Unit

A new APU will be installed to support black-start functionality and reliable starting of both CTG units following system outages. Black-start capability is required to energize auxiliary systems, initiate CTG startup, and restore local generation in the absence of an external power supply.

Based on vendor requirements, the new APU will be sized at approximately 1.5 MW and will be capable of supplying sufficient power to support startup and auxiliary loads for either CTG unit independently, as well as associated control and protection systems. A transfer switching arrangement will be provided to allow the APU to selectively supply auxiliary power to either CTG unit as required, ensuring operational flexibility during startup, maintenance, or outage conditions.

As part of the project scope, the existing APU and associated propane fuel storage system will be removed. The new APU will be fueled from a base mounted fuel storage tank. The APU and transfer switching arrangement will be integrated with the generator controls and protection systems to support safe operation and coordinated system restoration.

Yard Expansion

The proposed project includes expansion of the existing site yard to accommodate installation of two CTG units, associated infrastructure, and a new auxiliary building. Newfoundland Power owns sufficient land adjacent to the existing facility, allowing the yard to be expanded within the current property boundaries as required.

Yard expansion will be undertaken to provide adequate space for placement and installation of the CT units, fuel storage tanks, auxiliary equipment, and construction of a new building to replace the existing deteriorated structure. Yard works will include site grading, fencing modifications, foundations, and adjustments to access roads and laydown areas as necessary to support demolition activities, new building construction, equipment installation, and long-term operation and maintenance of the new facilities.

Building

The existing building at the Greenhill site is in poor condition and will be removed as part of the proposed project. A new building will be constructed to support operation of the new CTGs. The new building will be designed to accommodate dedicated protection, control, and communications equipment, switchgear, maintenance functions, storage requirements, and other operational support needs associated with the facility.

Construction of a new building provides the opportunity to integrate protection, control, and communications systems for both the new CTG generating units and associated substation equipment into a single, optimized layout.

Building works will include demolition and removal of the existing structure, construction of new foundations and structure, and installation of architectural, mechanical, and electrical systems required to support facility operations. The new building will also be designed to accommodate installation of new 13.8 kV switchgear, including appropriate room separation, access, ventilation, and provisions for arc-flash exhaust chutes or pressure relief systems, as required.

Switchgear

The project will include replacement of the existing 13.8 kV switchgear to support the safe and reliable operation and isolation of the CTG. The existing switchgear is at end of life, is obsolete, and relies on components that are increasingly difficult to source, resulting in elevated operational and maintenance risk. The existing installation does not incorporate modern arc-flash mitigation features. The replacement switchgear will be designed to incorporate modern protection and control features, including arc-flash mitigation measures, to enhance personnel safety and improve operational flexibility.

Protection & Controls Systems

The existing protection and control systems will be replaced with new, modern systems consistent with current utility standards and best practices. Control and monitoring systems associated with the new CTGs will be provided as part of the vendor's scope and will include modern turbine controls, condition monitoring, and integrated HMIs. These systems will support reliable operation, diagnostics, and maintenance.

The upgraded protection and control architecture will improve reliability, reduce dependency on obsolete components, and enhance operational visibility and control.

Substation

The proposed project includes modifications and upgrades to substation components to support integration and reliable operation of the new CTGs.

The existing power transformer will remain in service, and a new power transformer will be installed in parallel to support the combined output of the approximately 30 MW CTG facility.

Existing obsolete protection and control equipment within the substation will be upgraded or replaced as required to ensure compatibility with the parallel transformer arrangement and the new generating units, and to align with current protection standards. These upgrades will support proper coordination between generation, transformers, and distribution protection systems.

New motorized air-break switches will be installed to provide enhanced isolation capability for both the existing and new generation transformers, as well as the distribution transformer. These switches will enhance the protection scheme and allow for safe and efficient isolation of equipment for maintenance and emergency operations.

A new 66 kV bus-tie breaker will be installed to improve protection and operational flexibility of the substation. The bus-tie breaker will enhance fault isolation capabilities and support reliable operation of the 66 kV system.

A 1.5 MVA station service transformer will be installed to facilitate CTG starting under normal conditions and to provide site power.

The project scope also includes installation of spill containment systems for both the existing power transformer and the new generation transformer. The spill containment systems are required to protect against environmental damage in the event of an oil spill and to mitigate safety risks associated with transformer oil releases.

9.0 PROJECT COSTS

9.1 Cost Estimate Approach

The cost estimates for the proposed WES and GRH projects have been developed based on the recommended CTG solution identified through the assessment of alternatives completed by S&L.

To support the development of project-specific capital cost estimates, Newfoundland Power retained Stantec to prepare cost estimates for each site. Stantec's scope included multidisciplinary engineering input across civil, structural, mechanical, electrical, instrumentation and control, and environmental disciplines to support the preparation of site-specific cost estimates. The Stantec cost estimates are provided in Appendix E.

The estimates developed by Stantec reflect a level of definition consistent with an AACE Class 3 estimate, supported by preliminary engineering, site layouts, and discipline-specific quantity take-offs. This represents an advancement from conceptual-level estimates provided in Appendix D titled *Generation Technology Assessment* used for early screening of the alternatives and provides an appropriate level of definition for regulatory review and capital approval.

Newfoundland Power has incorporated escalation and Allowance for Funds Used During Construction ("AFUDC") into the overall project costs. These components are developed using established Company practices, and regulatory methodologies consistent with prior capital project submissions.

Substation-related costs and integration scope have been developed by Newfoundland Power's Engineering group, which routinely prepares cost estimates for substation projects and has established experience delivering such estimates.

Estimate Basis and Maturity

The WES and GRH project cost estimates are based on a level of definition consistent with an AACE Class 3 estimate, which is appropriate for the current stage of project development. At this stage, the estimates are intended to support capital planning and approval while recognizing that certain scope elements will be refined during detailed engineering.

The estimates are based on a defined project scope with preliminary engineering and conceptual design development, along with preliminary site-specific layouts and system configurations. The estimates were developed using preliminary engineering deliverables, including site layouts, general arrangements, process flow diagrams, single-line diagrams, design basis documentation, and discipline-specific material take-offs and quantity-based estimating. Vendor budgetary quotations were also incorporated for several major equipment packages, including CTGs, switchgear, fuel tanks, and auxiliary generation equipment.

Earlier conceptual cost information developed as part of the S&L technology assessment was used to support alternative evaluation only and does not form the basis of the project cost estimates presented herein.

Contingency allowances are included to reflect uncertainties related to site conditions, scope definition, market pricing, and supply chain factors, consistent with estimating practice for this level of project definition.

Cost Anchors and Allowances

A substantial portion of the overall project cost is supported by discipline-level quantity take-offs, preliminary engineering design, and market-based budget pricing, providing meaningful cost anchoring at the current level of definition.

To improve estimate accuracy and increase cost confidence, vendor budgetary quotations were obtained for several major equipment packages, including CTGs, switchgear, black-start generators, fuel tanks, and other key electrical and mechanical systems. These quotations provide current market benchmarks for the largest project cost drivers and reduce reliance on conceptual estimating techniques.[28] Recent market conditions for CTGs have been explicitly considered, including allowances for price volatility beyond normal inflationary effects.

Owner's costs have been developed by Newfoundland Power using internal labour and material estimates and standards. Escalation and AFUDC have been calculated using established corporate and regulatory methodologies consistent with prior capital projects.

[28] Budgetary quotations received for major equipment represent approximately 40% to 50% of the project costs.

Contingency

Contingency allowances have been included to account for uncertainties associated with the current level of project definition. These uncertainties reflect the degree of scope development at this stage and include potential variations in site conditions, refinement of design details during detailed engineering, and market-related factors associated with procurement and construction.

Stantec completed separate Monte Carlo risk analyses for the WES and GRH projects to evaluate the potential range of project costs and quantify the impact of uncertainty on the estimate.[29] The analyses considered uncertainty associated with quantities, unit rates, equipment pricing, market conditions, and other project-specific risks.

For an AACE Class 3 estimate, the Monte Carlo analysis strengthens estimate reliability by providing a quantitative assessment of cost uncertainty and contingency requirements. Rather than relying solely on deterministic contingency allowances, the simulation evaluates the cumulative impact of individual estimating uncertainties and project risks, resulting in a more defensible and transparent estimate.

The resulting contingency allowances were established at a P90 confidence level, representing a project cost outcome that has approximately a 90% probability of not being exceeded based on the assumptions and uncertainty ranges used in the analysis.

The contingency allowances included in the WES and GRH project estimates total approximately $26.8 million, representing approximately 16.7% of the project costs before contingency, escalation, and AFUDC.

Escalation

Escalation has been applied separately to labour and non-labour cost components. Escalation reflects the application of forecast inflationary increases in labour and material costs over the project schedule. Non-labour escalation is calculated using the Canadian Gross Domestic Product ("GDP") Deflator, while labour escalation is based on the Company's internal labour escalation assumptions. Escalation is applied to the forecasted project cash flow derived from the Stantec cost estimates.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing capital expenditures incurred during the construction period of the project prior to it being placed into service.[30] AFUDC is calculated by applying the

[29] Monte Carlo simulation is a probabilistic modeling technique that assesses the combined effect of multiple cost risks and estimating uncertainties by repeatedly calculating project costs using thousands of iterations. For each iteration, key cost elements are varied within defined ranges based on their anticipated level of uncertainty, producing a distribution of potential project outcomes rather than a single deterministic value. The analysis allows project stakeholders to better understand the likelihood of achieving specific cost targets and provides insight into the level of contingency required to achieve a desired confidence level.

[30] Effective January 1, 2008, Newfoundland Power calculates AFUDC in a manner consistent with Order No. P.U. 32 (2007).

rate of return on average rate base approved by the Board to the estimated construction expenditures over the construction period, reflecting the cost of both debt and equity capital used to fund the project.[31] Capital expenditures are typically accumulated monthly, and AFUDC is calculated on the portion of the project that is under construction but not yet in service. Once the project is commissioned and placed into service, the capitalization of AFUDC ceases, and the accumulated AFUDC becomes part of the total capitalized project cost. The specific rates, calculation methodology, and treatment of AFUDC are consistent with applicable regulatory requirements and utility accounting practices.

Cost Estimate Uncertainty

Consistent with estimating practice at a Class 3 level of definition, some uncertainty remains, primarily associated with scope elements that have not yet been finalized through detailed engineering and competitive contractor procurement.

A significant portion of the total project cost, particularly major equipment supply, is supported by vendor budget pricing and discipline-based quantity estimates, reducing variability compared to conceptual estimates. Remaining uncertainty is largely associated with scope elements that will be further defined through detailed engineering, market engagement, and site investigations as the projects advance toward execution.

The cost estimates presented represent the best current estimate at this stage of development and include appropriate allowances for uncertainty, escalation, and financing. While some uncertainty remains, the estimates benefit from preliminary engineering and quantity-based development, with remaining variability expected to be refined as project definition advances through detailed design and procurement activities.

Consistent with AACE Class 3 estimating practices, Stantec's opinion of estimate accuracy is approximately +30% / -20%, reflecting the current level of project definition and the remaining uncertainty associated with scope refinement, procurement, and detailed engineering activities.

Summary of Project Costs

The proposed WES and GRH scopes have each been separated into a thermal generation project and a substation project to reflect the distinct asset classes included in this application.

Table 6 summarizes the estimated costs of the four projects and reconciles those costs to the combined application amount. The project costs include applicable contingency, escalation, and AFUDC.

[31] The 2026 rate of return on average rate base, as approved by the Board in Order No. P.U. 23 (2025), was used in the calculation of AFUDC for these cost estimates.

Table 6 Summary of Proposed Project Costs ($000s)			
Project	WES	GRH	Total
Thermal Generation Facility Refurbishment	85,863	147,842	233,705
Substation Upgrades for Thermal Generation	482	7,902	8,384
Total Proposed Project Costs	86,345	155,744	242,089

9.2 Wesleyville Project Costs

The WES scope has been separated into two projects to reflect the scope of work required for the distinct thermal generation and substation asset classes:

- Wesleyville Thermal Generation Facility Refurbishment
- Wesleyville Substation Upgrades for Thermal Generation

The following tables outline the costs for the WES scope.

Table 7 provides the cost breakdown for the *Wesleyville Thermal Generation Facility Refurbishment* project, which has a total project cost of $85,863,000. Additional details are provided in Appendix E titled *Cost Estimates*.

Table 7 Wesleyville Thermal Generation Facility Refurbishment Project Cost ($000s)	
Cost Category	Cost
Direct Construction Costs[32]	40,267
Indirect Construction Costs[33]	7,684
Owner's Costs[34]	9,370
Subtotal	57,321
Contingency	9,295
Subtotal (incl. Contingency)	66,616
Escalation	7,680
Subtotal (incl. Contingency & Escalation)	74,296
AFUDC	11,567
TOTAL	$85,863

[32] Direct construction costs include equipment supply, installation, civil works, electrical works, mechanical works and commissioning.
[33] Indirect construction costs include contractor supervision, temporary facilities, mobilization, quality control, and site support.
[34] Owner's costs include engineering, project management, internal labour and administration.

Table 8 provides the cost breakdown for the *Wesleyville Substation Upgrades for Thermal Generation* project, which has a total project cost of $482,000.

Table 8 Wesleyville Substation Upgrades for Thermal Generation Project Cost ($000s)	
Cost Category	**Cost**
Direct Construction Costs	182
Indirect Construction Costs	45
Owner's Costs	149
Subtotal	**376**
Contingency	40
Subtotal (incl. Contingency)	**416**
Escalation	58
Subtotal (incl. Contingency & Escalation)	**474**
AFUDC	8
TOTAL	**$482**

Tables 9 and 10 provide the consolidated cost breakdown for the overall WES project scope including both the *Wesleyville Thermal Generation Facility Refurbishment* project and the *Wesleyville Substation Upgrades for Thermal Generation* project. The combined total project cost is $86,345,000.

Table 9 Overall Wesleyville Scope Project Cost ($000s)	
Cost Category	**Cost**
Direct Construction Costs	40,449
Indirect Construction Costs	7,729
Owner's Costs	9,519
Subtotal	**57,697**
Contingency	9,335
Subtotal (incl. Contingency)	**67,032**
Escalation	7,738
Subtotal (incl. Contingency & Escalation)	**74,770**
AFUDC	11,575
TOTAL	**$86,345**

Table 10 Overall Wesleyville Scope Project Cost ($000s)					
2027	2028	2029	2030	2031	Total
24,789	2,053	2,796	25,076	31,631	**$86,345**

9.3 Greenhill Project Costs

The GRH scope has been separated into two projects to reflect the scope of work required for the distinct thermal generation and substation asset classes:

- Greenhill Thermal Generation Facility Refurbishment
- Greenhill Substation Upgrades for Thermal Generation

Tables 11 and 12 outline the costs for the GRH scope.

Table 11 provides the cost breakdown for the *Greenhill Thermal Generation Facility Refurbishment* project, which has a total project cost of $147,842,000. Additional details are provided in Appendix E titled *Cost Estimates*.

Table 11 Greenhill Thermal Generation Facility Refurbishment Project Cost ($000s)	
Cost Category	Cost
Direct Construction Costs	75,786
Indirect Construction Costs	9,541
Owner's Costs	11,875
Subtotal	**97,202**
Contingency	16,079
Subtotal (incl. Contingency)	**113,281**
Escalation	13,409
Subtotal (incl. Contingency & Escalation)	**126,690**
AFUDC	21,152
TOTAL	**$147,842**

Table 12 provides the cost breakdown for the *Greenhill Substation Upgrades for Thermal Generation* project, which has a total project cost of $7,902,000.

Table 12 Greenhill Substation Upgrades for Thermal Generation Project Cost ($000s)	
Cost Category	**Cost**
Direct Construction Costs	3,695
Indirect Construction Costs	922
Owner's Costs	1,065
Subtotal	**5,682**
Contingency	1,380
Subtotal (incl. Contingency)	**7,062**
Escalation	711
Subtotal (incl. Contingency & Escalation)	**7,773**
AFUDC	129
TOTAL	**$7,902**

Tables 13 and 14 provide the consolidated cost breakdown for the overall GRH scope including both the *Greenhill Thermal Generation Facility Refurbishment* project and the *Greenhill Substation Upgrades for Thermal Generation* project. The combined total project cost is $155,744,000.

Table 13 Overall Greenhill Scope Project Cost ($000s)	
Cost Category	**Cost**
Direct Construction Costs	79,481
Indirect Construction Costs	10,463
Owner's Costs	12,940
Subtotal	**102,884**
Contingency	17,459
Subtotal (incl. Contingency)	**120,343**
Escalation	14,120
Subtotal (incl. Contingency & Escalation)	**134,463**
AFUDC	21,281
TOTAL	**$155,744**

Table 14 Overall Greenhill Scope Project Cost ($000s)					
2027	2028	2029	2030	2031	Total
46,406	3,512	6,090	46,709	53,027	$155,744

9.4 Operations & Maintenance, and Sustaining Capital Costs

In addition to capital costs, the proposed WES and GRH projects will incur ongoing operations and maintenance ("O&M") costs throughout their service lives. As part of the S&L technology assessment, fixed O&M costs, variable O&M costs, and sustaining capital costs were developed for each technology alternative. These estimates were used to support the assessment of alternatives and to evaluate the long-term cost implications of the various replacement technologies. Newfoundland Power subsequently refined these estimates to reflect the proposed WES and GRH facilities and the Company's expected operating and maintenance practices.

Fixed Operations and Maintenance Costs

Fixed O&M costs represent expenditures that are generally incurred regardless of unit operating hours. These costs include Newfoundland Power operating and maintenance labour, routine inspections, preventative maintenance activities, equipment testing, regulatory compliance requirements, condition monitoring, contractor support, and general facility upkeep.

Variable Operations and Maintenance Costs

Variable O&M costs are directly related to facility operation and generally increase with unit dispatch and operating hours. These costs typically include Newfoundland Power operating and maintenance labour associated with unit operation, consumable materials, maintenance activities associated with equipment operation, replacement of operating components, fuel handling activities, and other operating expenditures that vary with unit usage.

Sustaining Capital Costs

Sustaining capital costs represent the capital expenditures expected to be incurred over the service life of the generating facilities beyond the initial construction cost. These costs include periodic capital expenditures, minor refurbishments, and major overhauls required to maintain safe and reliable operation throughout the facilities' service lives. Given the intended role of the facilities as backup, contingency, and peak demand resources, annual operating hours are expected to remain relatively low, which reduces equipment wear and extends overhaul intervals, thereby limiting capital costs over the service life of the facilities.

A summary of the fixed O&M costs, variable O&M costs, and sustaining capital costs developed for the technologies assessed is provided in Table 15.

Table 15
Annual O&M and Sustaining Capital Cost Estimates
($000s)

Facility	Fixed O&M Cost	Variable O&M Cost	Average Sustaining Capital Cost[35]
Wesleyville	225	89	377
Greenhill	364	113	703

9.5 Customer Rate Impacts

In compliance with the spirit and intent of the Board's Provisional Guidelines, this section provides a proposed budget impact summary that assesses the revenue requirement impact and indicative electricity rates assuming that the Application is approved.[36]

Beginning in 2032, the capital expenditures proposed in the Application are estimated to increase the Company's annual revenue requirement by approximately $25 million on a *pro forma* basis. The estimate includes the full year impact of depreciation, return on rate base, operating costs and income taxes.[37] This change in revenue requirement is estimated to increase customer rates by approximately 2.2% in 2032 on a *pro forma* basis.

10.0 PROJECT SCHEDULES

At this stage of project development, schedules for the WES and GRH projects are indicative and intended for planning purposes. Detailed project schedules, including critical path activities and major milestones, will be refined through subsequent stages of project approval, procurement, planning and design. Schedule uncertainty is expected to reduce as the projects advance through detailed engineering and as long-lead time equipment procurement is initiated.

[35] Sustaining capital costs vary year-to-year over the lifetime of the CTGs. The values presented in this table represent the average annual sustaining capital cost over the facilities' assumed 35-year service lives.

[36] Appendix A of the Provisional Guidelines lays out the filing requirements for a utility's annual capital budget, as a whole, and is divided into sections I, II, and III. With respect to the requirements laid out in section I of Appendix A (General Context), which includes a rate impact summary, there is no explicit obligation to include this information in supplemental capital applications. Instead, the Provisional Guidelines state that supplemental capital applications "*should be supported with evidence and analysis similar to the requirements for annual capital budget applications.*" See the Provisional Guidelines, page 6 of 18.

[37] Depreciation expense is based on a 35-year service life for the new CTGs. Return on rate base is based on Newfoundland Power's current incremental weighted average cost of capital of 6.57%. O&M is based on the estimates provided in Table 15. Income tax is based on an income tax rate of 30%.

The proposed projects follow a conventional utility project delivery sequence. Key schedule drivers common to both projects include:

- Equipment specifications, tendering and procurement for major equipment,
- Lead times associated with major equipment supply,
- Detailed engineering and preparation of construction specifications,
- Site preparation activities, including civil works, yard expansion, and foundations,
- Building works, including modification of the existing building at WES and construction of a new building at GRH,
- Construction and installation of mechanical and electrical systems, and
- Commissioning and testing activities.

At a high level, the indicative project schedule is expected to be executed over a multi-year period. Current vendor information indicates that CTG procurement lead times are approximately three to four years, which represents the primary driver of the overall five-year project schedule.

Years one through three are anticipated to focus on detailed engineering, development of equipment specifications, tendering activities, and procurement of long-lead time equipment. This period also includes advancement of project planning and preparation of construction packages.

Year four is expected to focus on site preparation activities, including civil and structural works, yard expansion, and building works at both sites. Year five is expected to encompass construction, installation of mechanical and electrical systems, commissioning, and integration of the new facilities into service.

The schedule for both projects reflects the advantages of established generating sites with existing transmission interconnections, site access infrastructure, and operational familiarity. Detailed schedules will sequence major construction and commissioning activities between WES and GRH to reflect contractor availability, system operating requirements, and the need to manage simultaneous execution risk.

11.0 ENVIRONMENTAL CONSIDERATIONS

The proposed WES and GRH projects will be subject to applicable provincial and federal environmental legislation and permitting requirements.

11.1 Compliance with Environmental Regulations

Gas turbine installations are required to conform to a range of environmental and regulatory frameworks governing project approval, air emissions, fuel storage, and environmental protection. The applicable permitting and regulatory requirements for each project will be identified and addressed through the environmental assessment, detailed engineering, and regulatory review processes.

Stantec's environmental review indicates that both projects will require registration under the Newfoundland and Labrador Environmental Assessment process based on the capacity of the

proposed generating facilities. The review also determined that a federal Impact Assessment is not anticipated to be required based on the current project scope. While environmental assessment registration and various permits and approvals will be required prior to construction, no environmental issues have been identified that would preclude project implementation.

The anticipated operating profile of these units as local-reliability, contingency-response, and system-support resources is expected to result in lower overall environmental impacts than continuously operating baseload thermal generation. From an emissions perspective, these CTGs differ from traditional baseload thermal generating stations in that they are intended to operate primarily in support of system reliability during peak demand periods, contingency events, and transmission outages, rather than as continuous sources of generation. As a result, overall emissions are expected to be low. The proposed CTGs will utilize combustion technology to minimize NOx emissions. To minimize sulphur dioxide ("SO_2") emissions, the CTGs will be fueled with ultra-low sulphur diesel.

In addition, the proposed CTGs will be designed with the capability to operate on alternative fuels in the future, subject to availability and required system modifications. This design flexibility supports adaptability to future changes in fuel supply and emissions reduction strategies and reduces the risk of asset stranding over the project life.

Fuel storage systems will be designed in accordance with current regulatory standards, including double-walled floors, leak detection, and spill containment measures to minimize environmental risk. Spill containment for oil-filled equipment and waste fuel/oil drainage catchment/separators will be installed. These measures will reduce the risk of environmental impacts associated with fuel storage and oil handling.

Construction activities will incorporate standard environmental protection practices to mitigate potential impacts related to site disturbance, drainage, and construction operations. At both WES and GRH, the use of existing developed sites is expected to limit incremental environmental impacts relative to new greenfield development.

11.2 Compliance with Clean Electricity Regulations

The Government of Canada's Clean Electricity Regulations ("CER") came into effect in December 2024.[38] The purpose of the CER is to protect the environment and human health from the threat of climate change by establishing a regime that prohibits excessive carbon dioxide (CO_2) emissions from the use of fossil fuel to generate electricity.[39] The CER applies to fossil-fuel-fired generating units that have a capacity of at least 25 MW and are connected, directly or indirectly, to an electricity system.[40]

[38] Government of Canada: Powering Canada's Future – Canada's final *Clean Electricity Regulations*, December 2024, https://www.canada.ca/en/environment-climate-change/news/2024/12/powering-canadas-futurecanadas-final-clean-electricity-regulations.html, retrieved on August 8, 2026.

[39] Clean Electricity Regulations SOR/2024-263, Section 1, https://laws-lois.justice.gc.ca/eng/regulations/SOR-2024-263/20250101/P1TT3xt3.html, retrieved on August 8, 2026.

[40] Clean Electricity Regulations SOR/2024-263, Section 5(1).

The CER recognizes that some fossil fuel sources of generation may be required for system reliability and permits a limited amount of CO_2 emissions up to year 2049.[41] The CER also provides flexibility mechanisms, including the exclusion of qualifying emergency-operation emissions and the use of compliance credits and Canadian offset credits, which may further support compliance if annual emissions are in excess of the annual thresholds.[42]

Based on the proposed unit configurations and anticipated operating profiles, WES is not expected to be subject to the CER annual emissions limit, while GRH is expected to operate within the applicable annual limit.

Wesleyville

The proposed WES CTG project will result in the WES facility having a maximum capacity of 15 MW. This is less than the 25 MW threshold established in the CER. Therefore, the WES CTG project is not expected to be subject to the CER emissions limit requirement.

Greenhill

The proposed GRH CTG project will result in the GRH facility having a maximum capacity of 30 MW. This is greater than the 25 MW threshold established in the CER. Accordingly, the GRH project is subject to the applicable CER emissions requirements. Section 9 of the CER establishes the annual emissions limitations for CO_2 emitting sources of electricity.

The emissions limits defined in the CER are shown in Figure 7.

Emission limit

9 (1) The responsible person for a unit must not emit from the unit in a calendar year a quantity of CO_2, determined in accordance with section 12, that exceeds the limit, expressed in tonnes, determined by the formula

$$\mathbf{C \times I_{el} \times 8760 \times 0.001}$$

where

C is the unit's electricity generation capacity for the calendar year; and

$\mathbf{I_{el}}$ is the emissions intensity applicable to the calendar year and is

(a) 65 tonnes of CO_2 emissions per GWh for the 2035 to 2049 calendar years, and

(b) 0 tonnes of CO_2 emissions per GWh for the 2050 and subsequent calendar years.

Figure 7 – Annual Limit on Emissions Calculation

[41] Clean Electricity Regulations SOR/2024-263, Section 9. Beyond 2049, the CER does not permit CO_2 emissions.
[42] Clean Electricity Regulations SOR/2024-263, Section 25 Emergency Circumstances, Section 28 Canadian Offset Credits, and Section 30 Compliance Credits.

The annual emissions limit for the proposed 30 MW GRH project would be approximately 17.1 kt of CO_2. Based on the assumed diesel-fuel characteristics, this limit corresponds to approximately 770 full-load operating hours.[43] The CER also allows qualifying emergency-operation emissions to be excluded from annual emissions determinations under specified circumstances. Based on historical operation of the GRH CTG for local reliability support, transmission contingencies, and system emergency events, the Company expects annual emissions from the GRH CTG to remain below the CER emissions limit until 2049 as required by the CER.[44] Beyond 2049, compliance with the CER would be subject to the regulatory requirements in effect at that time, including any applicable provisions related to qualifying emergency operation and emissions offsetting. Future compliance measures, including the potential use of lower-carbon fuels or other technological developments, would be evaluated as part of the Company's ongoing generation planning activities.

12.0 STAKEHOLDER ENGAGEMENT

The WES and GRH thermal generation facilities have long-standing roles in the areas in which they operate. The WES facility has operated in the Bonavista Bay north coast area since 2003, while the GRH facility has operated on the Burin Peninsula since 1975. Electricity supplied in these areas supports rural residential and business customers, municipal infrastructure, essential services, telecommunications systems, and other community activities.[45]

Newfoundland Power recognizes that early and ongoing engagement with communities and stakeholders is an important component of developing the proposed WES and GRH projects. The objectives of the engagement undertaken to date were to:

- advise stakeholders of the condition and expected retirement of the existing CTGs;
- explain the need for replacement generation at the existing sites;
- provide an overview of the proposed project scopes and anticipated development process;
- explain the local reliability, transmission-support, and IIS capacity functions performed by generation at WES and GRH; and
- provide stakeholders with an opportunity to raise questions, identify local considerations, and provide feedback on the proposed projects.

As part of early project development, Newfoundland Power held engagement sessions with municipal representatives, area Members of the House of Assembly, local employers, and other stakeholders in the Bonavista Bay north coast and Burin Peninsula regions. The sessions included information on the condition of the existing facilities, the basis for their replacement,

[43] Newfoundland Power's calculations are based on a CO_2 emission factor for No. 2 diesel fuel of 2,677 g CO_2/L, and CTG fuel consumption at full load of 8,252 L/hr. The resulting estimate of approximately 770 full-load operating hours is comparable to the approximately 700 annual operating hours estimated by S&L in Appendix D.

[44] The maximum annual usage of the GRH CTG over the 2006 to 2025 period occurred in 2014 and was 133 hours. This was largely to address shortages in available generation, challenges brought on by blizzard conditions, and a series of major electrical system disruptions during the January 2-8, 2014 period known as #DarkNL.

[45] In addition to customers that can be described as residential and business customers, electricity supply from Newfoundland Power also supports municipal infrastructure such as municipal buildings, water and sewer facilities, street and area lighting, traffic lighting, and telecommunications systems, as examples.

the role of thermal generation in supporting reliable electricity service, and the principal components of the proposed projects.

During the discussions, Newfoundland Power explained that the existing WES and GRH CTGs are approaching the end of their service lives and that the proposed projects would refurbish the existing sites to allow them to continue to operate in the future.

Following the engagement sessions, Newfoundland Power received written expressions of support for the proposed projects from municipal and business stakeholders. The support letters provided by the stakeholders are summarized in Table 16.

Table 16
Written Expressions of Stakeholder Support
WES and GRH

Project	Stakeholder
WES	Town of Centreville-Wareham-Trinity
WES	Town of Hare Bay
WES	Town of New-Wes-Valley
WES	Beothic Fish Processors Ltd.
GRH	Town of Garnish
GRH	Town of Grand Bank
GRH	Town of Lawn
GRH	Town of Marystown
GRH	Town of Parker's Cove
GRH	Town of St. Lawrence
GRH	Clearwater Seafoods

The letters of support identify the importance stakeholders place on reliable electricity service and on maintaining local generation capability in the two rural areas. The letters refer to anticipated benefits associated with backup generation, broader system resilience, continuity of service for residents and businesses, support for essential and municipal services, and regional economic activity. Copies of the written expressions of support are provided in Appendix F titled *Stakeholder Engagement Letters of Support*.

The letters represent the views of the stakeholders that provided them and form part of the broader project-engagement record. Newfoundland Power will continue engagement as the projects advance and additional information becomes available through environmental assessment, detailed engineering, procurement, and construction planning.

Future engagement will be proportionate to the nature and timing of project activities and is expected to include:

- providing information on material changes to project scope or schedule;
- communicating the timing and nature of construction activities that may affect nearby communities;
- providing appropriate channels through which stakeholders can submit questions or concerns;
- considering relevant local information in construction and execution planning; and
- responding to material stakeholder matters identified during project development and construction.

Newfoundland Power will continue to keep affected communities and other stakeholders informed of relevant project developments. Stakeholder engagement will continue through project development and construction, with the nature and frequency of updates adjusted to reflect the activities occurring at each project site.

13.0 PROJECT EXECUTION RISKS AND OPPORTUNITIES

The proposed WES and GRH projects have been developed based on preliminary engineering, vendor budget pricing, quantity-based estimating, and current market information. While the estimates include contingency, escalation, and other allowances appropriate for the current level of project definition, several factors may influence project execution, schedule, and cost.

Combustion Turbine Procurement

CTGs represent a significant portion of the overall project cost and are currently subject to extended manufacturing and delivery lead times. Delays in equipment procurement, manufacturing, transportation, or delivery could affect the overall project schedule and increase project costs.

To mitigate this risk, Newfoundland Power will advance engineering and procurement planning activities early in the project development process. Vendor budgetary quotations have been incorporated into the project estimates and the proposed project schedules reflect currently available information regarding turbine procurement timelines. In addition, the cost estimates include a specific escalation allowance associated with CTG procurement to account for potential future price increases prior to equipment purchase. This allowance reflects current market conditions and recent vendor pricing information obtained during estimate development.

Supply Chain Constraints

Supply chain constraints continue to affect the availability and delivery timelines of major electrical and mechanical equipment. Global demand for power generation equipment, electrical infrastructure, specialized materials, and associated components may result in extended lead times, reduced equipment availability, and increased costs.

To mitigate this risk, Newfoundland Power will advance engineering and procurement planning activities as part of the early stages of project development. Major equipment procurement activities will be initiated as early as practical to secure manufacturing slots, reduce exposure to supply chain disruptions, and accommodate the extended delivery timelines currently being experienced throughout the power generation industry. Vendor budget quotations have also been incorporated into the project estimates to better reflect current market conditions and equipment availability.

Contractor and Labour Availability

The proposed projects are expected to be undertaken during a period of significant utility, industrial, and infrastructure investment activity within Newfoundland and Labrador and across North America. Competition for skilled labour, contractor resources, specialized trades, and construction equipment may affect project execution, productivity, and pricing.

To mitigate this risk, Newfoundland Power intends to advance engineering and procurement activities early in the project lifecycle and will seek to issue construction and equipment procurement packages as early as practical. Early engagement with contractors and suppliers is expected to improve visibility into market conditions, support workforce planning, and reduce the risk of delays associated with contractor and labour availability. In addition, the project schedules have been developed to recognize current market conditions and anticipated resource requirements over the course of project execution.

Fuel Supply During Extended Contingencies

Newfoundland Power maintains fuel supply arrangements to support the delivery of diesel fuel to its generating facilities as required. In the event operation is expected to exceed the on-site storage capacity, fuel deliveries would be arranged to replenish inventory and support continued operation. Where necessary, additional suppliers could be engaged to help ensure fuel availability during extended operating events or emergency conditions.

The available on-site fuel storage is considered sufficient to support normal operation of the facilities with planned fuel deliveries. However, extended operation during major or prolonged system contingencies may require additional fuel supply measures. Newfoundland Power will continue to coordinate with Hydro and fuel suppliers regarding fuel supply requirements and overall contingency planning for such events.

Newfoundland Power will support Hydro's fuel supply adequacy analysis to ensure that the fuel requirements of the proposed WES and GRH facilities are considered as part of broader contingency planning for the IIS. Hydro has confirmed that its assessment will consider fuel requirements for all thermal generating sources on the Island, including the proposed facilities.

Cost Escalation

The proposed projects are multi-year projects that are expected to be executed over approximately five years. As a result, project costs are exposed to inflationary pressures affecting labour, equipment, materials, transportation, and construction services.

To address this risk, escalation has been incorporated into the project estimates using established Newfoundland Power methodologies and forecast cost indices. Proposed project schedules have also been developed to support timely execution and reduce exposure to future cost increases.

Schedule Delays

The successful execution of the projects depends on a range of factors, including regulatory approvals, completion of detailed engineering, equipment procurement, contractor availability, site access, and construction sequencing. Delays in any of these activities could affect overall project costs and expected in-service dates.

Newfoundland Power has sought to mitigate schedule risk by advancing project planning and engineering activities, utilizing existing generation sites and infrastructure where practical, and developing schedules that reflect current procurement lead times and construction execution requirements.

Project Opportunities

The proposed projects also benefit from several factors that reduce execution risk and support successful project delivery. Both projects will be constructed at existing generating sites with established transmission interconnections, available property, and existing infrastructure. In addition, Newfoundland Power has extensive experience operating and maintaining CTG facilities and has a long history of delivering generation, transmission, and substation projects throughout its service territory.

Depending on final equipment selection, the proposed projects may benefit from the use of modular CTG packages. Major equipment is factory-assembled and tested prior to shipment, reducing on-site construction complexity, shortening installation and commissioning schedules, and improving overall project execution. The modular approach also reduces exposure to site-specific construction risks, and labour constraints, while improving quality control through factory fabrication and testing.

These factors reduce overall project complexity relative to greenfield development and support efficient project execution.

14.0 CONCLUSION

The condition assessments conclude that the existing WES and GRH facilities have reached the end of their service lives and should be retired. The Planning Study identifies firm, dispatchable capacity of approximately 15 MW at WES and 30 MW at GRH as part of the recommended and least-cost planning solution, while the technology assessment identifies CTG technology as the recommended least-cost means of implementing the required firm, dispatchable capacity.

Newfoundland Power therefore proposes to refurbish the WES facility with one nominal 15 MW CTG and the GRH facility with two nominal 15 MW CTGs, together with the site, fuel, electrical, building, protection and control, and substation work described in Section 8. The proposed

projects will use existing generation sites and infrastructure where practical and are supported by the Class 3 project cost estimates presented in Section 9.

Newfoundland Power is therefore seeking approval to proceed with the proposed WES and GRH projects at a combined estimated cost of $242.1 million, comprising $86.35 million for WES and $155.74 million for GRH. The projects represent the least-cost means of replacing the required local-reliability, transmission-support and firm-capacity functions of the existing facilities. Newfoundland Power will report periodically to the Board on material developments affecting project scope, cost, schedule and execution.

APPENDIX A:

Thermal Generation Condition Assessment

Thermal Generation Fleet Review

Greenhill, Wesleyville,
Grand Bay and Port Aux Basques, NL

Stantec

Prepared for:
Newfoundland Power

May 4, 2026

Prepared by:
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Project/File:
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Revision	Description	Author	Date	Quality Check	Date	Independent Review	Date
2	Final	RBG	5/4/2026	KM	5/4/2026	PGO	5/4/2026

The conclusions in the Report titled Thermal Generation Fleet Review are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

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Executive Summary

Stantec has been engaged by Newfoundland Power (NP) to perform an assessment of four units of Newfoundland Power's thermal generation fleet, as follows:

- Combustion turbine generator (CTG) installation at Greenhill, NL.
- Combustion turbine generator installation at Wesleyville, NL.
- Combustion turbine generator installation at Grand Bay, NL
- Diesel engine generator (DEG) installation at Port aux Basques, NL.

As part of this assessment, other components have been evaluated including protection and control devices, switchgear, buildings and enclosures, fuel storage and associated piping systems.

Newfoundland Power has provided previous reports and test data which have been reviewed and evaluated, with some of the information forming part of this assessment and conclusions. Stantec personnel completed site visits for the four sites, to complete visual inspections of each installation.

The following are the findings and conclusions:

1. Greenhill CTG, although nominally rated for 25 MW, is presently de-rated to 20 MW to limit power turbine casing cracking and has reached the end of its service life due to its age, condition and lack of vendor support. This creates expanded reliability risks and operational uncertainty. As a result, Newfoundland Power should plan to retire the Greenhill CTG.
2. Wesleyville CTG, although nominally rated for 14.7 MW is presently de-rated to 8 MW due to gearbox vibration and has reached the end of its service life due to its age, condition and lack of vendor support. This creates expanded reliability risks and operational uncertainty. As a result, Newfoundland Power should plan to retire the Wesleyville CTG.
3. The Grand Bay CTG and the Port aux Basques DEG are increasingly less reliable due to age, condition, obsolescence and parts availability and are nearing their end of service life. This creates expanded reliability risks and operational uncertainty. As a result, Newfoundland Power should plan to retire both units.

Acronyms / Abbreviations

AEI	Associated Electrical Industries
AVR	Automatic Voltage Regulator
CEATI	Centre of Energy Advancement through Technical Innovation
CI	Condition Index
CTG	Combustion Turbine Generator
DEG	Diesel Engine Generator
GG	Gas Generator
HMI	Human Machine Interface
IR	Insulation Resistance
MCC	Motor Control Center
NP	Newfoundland Power
NLH	Newfoundland & Labrador Hydro
OEM	Original Equipment Manufacturer
PI	Polarization Index
PT	Power Turbine
P&C	Protection and Control
RR	Rolls Royce

1 Overview

1.1 Background

Newfoundland Power's thermal generation fleet provides emergency back-up power and electrical power system support. It includes three stationary liquid fueled CTGs and one stationary DEG, as well as two mobile units.

The two mobile units not included in this review are:

- Mobile Gas Turbine 2 (MG2) which is normally stationed in Whitbourne.
- Mobile Diesel 3 (MD3) which is normally stationed in Grand Bay Substation.

The four stationary units included in this review are:

- 25 MW Greenhill CTG which is in the community of Grand Bank off Route 210 on the Burin Peninsula. The unit is connected to the island grid via 66 kV transmission lines 301L and 305L.
- 14.7 MW Wesleyville CTG, which was previously located in Salt Pond, but relocated to the community of New-Wes-Valley off Route 320 in 2003. The unit is connected to the island grid via 66 kV transmission line 116L.
- 7 MW Grand Bay CTG in the community of Grand Bay West on Route 1 Trans-Canada Highway. The unit is connected to the island grid via the 66 kV transmission lines 417L, 416L and TL215. The unit supplies the local 12.5 kV distribution network via lines GBS-01 and GBS-02.
- 2.5 MW Port aux Basques DEG in the community of Channel-Port aux Basques off High Street and Rowe Street. The unit is connected to the island grid via the 66 kV transmission line 417L and supplies the local 12.5 kV distribution network via lines PAB-05 and PAB-03.

These four units were originally purchased in the 1969-1975 timeframe and have undergone various equipment upgrades and modernization over the years. Given the vintage of these facilities, Newfoundland Power has engaged Stantec to provide a review of the units regarding long-term viability of continued investment in the assets and to evaluate various options for rehabilitation, replacement or retirement.

1.2 Condition Assessment Grading

Stantec has performed the condition assessment of each unit using a grading scheme adapted from the Centre of Energy Advancement through Technical Innovation (CEATI) hydroAMP (Hydro Asset Management) methodology. The CEATI hydroAMP program utilizes a structured, collaborative

framework for assessing the condition of critical equipment, helping utilities with asset management, risk assessment, and investment decision-making. Its methodology involves a two-tiered assessment process that standardizes data collection on equipment performance, maintenance history, and physical condition to facilitate consistent, objective condition evaluations across projects and organizations. The methodology supports long-term investment strategies, capital prioritization, and budgeting for operations and maintenance.

The hydroAMP methodology involves a structured, two-tiered framework for condition assessment:

1. Standardized Assessment: Critical equipment is assessed using a consistent, objective process.
    - Data Collection & Standardization: Equipment Condition Data: Information on physical condition, performance, and maintenance history is collected.
2. Decision-Making Support: The standardized data enables:
    - Risk Assessment: Identifying potential failure points and risks.
    - Investment Strategy: Developing long-term plans for capital spending.
    - Prioritization: Focusing resources on critical equipment and projects.
    - Benchmarking: Allowing for comparison of asset condition and performance between different plants and organizations.

The adapted grading scheme utilized is as follows:

Table 1-1: Condition Index Ratings of Equipment

Condition Index (CI)	
7 ≤ CI ≤ 10	Good
3 ≤ CI <7	Fair
0 ≤ CI < 3	Poor

Table 1-2: Component Weights - CTG

Component	Weight
Gas Generator	0.25
Power Turbine	0.25
Speed Reduction Gearbox	0.10
Generator	0.25
Building/Exhaust/Intake	0.05
Fuel System	0.05
Electrical/P&C/Batteries	0.05
Sum	1.00

Table 1-3: Component Weights - DEG

Component	Weight
Engine	0.35
Generator	0.35
Building/Exhaust/Intake	0.10
Fuel System	0.10
Electrical/P&C/Batteries	0.10
Sum	1.00

2 Greenhill CTG

2.1 Greenhill Gas Generator, Power Turbine, Electrical Generator and Auxiliary Systems

The 25 MW Greenhill CTG Power Plant consists of a Rolls Royce (RR) Industrial Olympus "C" gas generator (GG) coupled with a Curtiss-Wright power turbine (PT), and a Brush AC generator. The plant was originally commissioned in 1975 by NP and has been in standby mode for most of its operating life, with limited service as a synchronous condenser. Significant capital maintenance has been completed on Greenhill CTG across its lifespan with the first significant upgrade in 1995, when the facility was 20 years old. The Olympus GG was overhauled, and a cracked PT casing was replaced with a used casing from a similar unit. Additional remediation work was completed in 2016.

The electrical generator power output is stepped up from 13.8 kV to 66 kV through a single step-up transformer in the substation for transmission to the local NP grid. The unit is fired with liquid fuel (diesel) and does not utilize any form of emission controls or NOx abatement.

The PT and generator are directly coupled and operate at 3600 RPM. While the unit does not include a gearbox, it is equipped with a clutch system allowing the generator to be operated as a synchronous condenser.

In recent years, annual run times have generally been limited to less than 100 hours per year. It was used for system support at the request of NLH during the "Dark NL" event in 2013/2014.



Figure 2-1: Greenhill CTG Power Plant

2.1.1 Gas Generator

The GG underwent an overhaul in 1995. Following an engine module fire in 1998, the GG was returned to Rolls Wood Group for cleaning and repair and in 2016, the GG was sent to Alba Power for a complete overhaul. In 2024, Sulzer did an internal boroscope inspection and found the unit to be in good condition. A small oil leak from the number 8 bearing was repaired.

Production of the RR Industrial Olympus GG's began in 1966 and ended in 1985. Over 320 units were sold in 20 countries for peaking power plants, including black start units for large thermal plants and standby units for nuclear power stations. Fewer than 125 industrial Olympus units remain in service. RR discontinued support for Industrial Olympus in 2006 because of a shrinking fleet and the increasing cost of parts from suppliers, with factory support ending entirely in 2015. Maintenance and limited parts support are now provided through third party vendors.

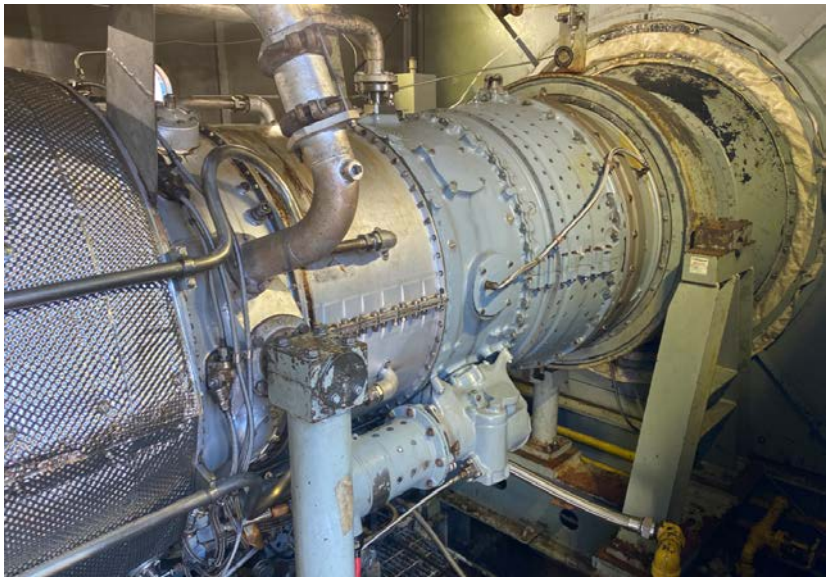


Figure 2-2: Greenhill Gas Generator

2.1.2 Power Turbine

The Curtiss-Wright PT has experienced cracking problems in the casing, which was identified in 1984 by the original equipment manufacturer (OEM) as a critical service concern. To mitigate crack propagation, the unit has been de-rated from 25 MW to 20 MW to limit the exhaust gas temperatures, in accordance with the OEM recommendations. In 1995, NP installed a surplus original OEM casing and replaced the internal bolting and fastening components. Cracking has occurred in the replacement casing and continues to be monitored. The exhaust volute, although original, is currently considered to be in fair condition and has not had any notable issues.

In 2003, the PT was reinsulated and realigned during the replacement of the exhaust stack. Repairs to the exhaust stack, compressor piping, and stator blade spacers were completed in 2008 and 2009. A

2014 inspection by Alba Power revealed a portion of the PT shrouding protruding into the gas path, along with continued casing and shroud cracking. In 2024, an inspection of the PT by Sulzer noted an increase in the quantity of visible full width cracks in the Stage 1 nozzle guide vane retaining ring and the appearance of additional micro cracks. Replacement of the PT would be required for continued reliable operation.

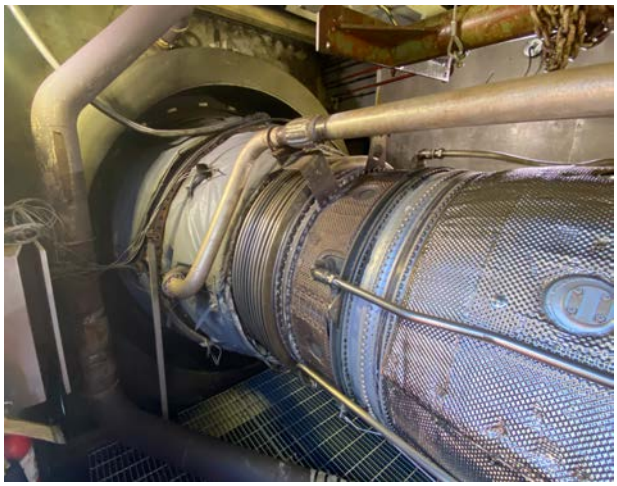


Figure 2-3: Greenhill Power Turbine

2.1.3 Electrical Generator

The Brush 31.8 MVA, type BDAX 70-76 generator is a direct-driven, two-pole, 3600 RPM synchronous machine. A clutch between the PT and the generator enables operation as a synchronous condenser.

The stator winding of the AC generator has been tested by NP, with the most recent results from 2024 confirming the unit is in good electrical condition. The generator polarization index (PI) is monitored for trending purposes and currently indicates that the insulation resistance (IR) of the stator winding is fair. As a primary operational concern, the rotor retaining rings, manufactured of 18Mn-5Cr, are known to be susceptible to stress corrosion cracking. The OEM has recommended replacing these rings with components made from a different material. Since the presence of cracking cannot be confirmed without full rotor disassembly, and due to the inherent material susceptibility to cracking and overall unit age/condition, replacement is recommended regardless of inspection findings.

In 2016, Brush provided a 25,000-hour inspection and recommended several maintenance actions including stator rewinding, rotor replacement (including new retaining rings), automatic voltage regulator (AVR) upgrade, enclosure repainting and bearing shaft seal refurbishment. The latter two items were completed by NP.

The excitation system, which includes a brushless exciter and the original Brush AVR, has not been upgraded since installation and is now obsolete, with replacement parts increasingly difficult to obtain.



Figure 2-4: Greenhill Electrical Generator and Clutch

2.1.4 Auxiliary Systems

The unit's lube oil system utilizes glycol cooling from outside coolers through heat exchangers in the building. While the system is generally in fair condition, the external glycol cooler would require replacement, due to deterioration, for continued reliable operation.



Figure 2-5: Greenhill Cooling System

2.2 Greenhill Fuel Oil System

The Greenhill facility includes three fuel oil storage tanks, each with a capacity of 100,000 litres. With usable capacity at 90% of installed tank capacity, this provides approximately 38 hours of operation at the derated load of 20 MW. Two of these tanks, installed in 2002, are exhibiting signs of corrosion

deterioration which is particularly noticeable on their tops. The third tank, installed in 2014, is generally in good condition. To ensure continued safe operations and to minimize environmental risks, all three of these tanks should be inspected annually and recoated as necessary.

These tanks comply with an older style ULC-S601 specification that has connections on the bottom of the tank. The tanks are acceptable to remain in service in the current setup, however, if there are major alterations or upgrades to the system, these tanks will need to be replaced with new units that have anti-syphon protection with all connections at the top of the tank.

For new systems installed, the NL GAP regulations (NLR 58/03) section 24(12) requires compliance to the National Fire Code. The 2025 fire code section 4.3.7.4 as well as CSA B139.1 section 8.7.2.4 require that new storage tank installs over 80,000 litres, even when double-walled, are now required to be placed in a secondary containment area, or have tertiary containment a minimum of 1.5m from the shell of the tank. As noted above, this only applies to new installations, the current arrangement onsite is able to remain in operation until major alterations are made.



Figure 2-6: Greenhill Fuel Oil Storage Tanks

The fuel forwarding system includes pumps at the tanks and pumps within the building. These pumps were assessed to be in good condition.



Figure 2-7: Greenhill Fuel Oil Pump Building

The fuel piping system, which is original to the installation in 1975, is in poor condition and would require replacement for continued operation. Several sections of insulation are missing and there is visible rusting on the pipe stands. The piping system requires a detailed inspection and will likely need to be replaced to maintain operational integrity and to minimize environmental risks.

2.3 Greenhill Electrical Systems

Most of the electrical systems are original to the installation in 1975 with some more recent upgrades limited to the batteries and control systems. The switchgear equipment, including the generator breaker, is housed in a separate building and remains in its original configuration. This switchgear equipment has exceeded its normal 25–30-year design life, is obsolete with parts becoming increasingly challenging to procure, is becoming increasingly difficult to maintain and does not meet current code and safety standards. This switchgear equipment is at end-of-life and would require replacement for continued reliable operation.



Figure 2-8: Greenhill Switchgear

The Westinghouse AC and DC motor control centers (MCCs) are also original and utilize obsolete mechanical relays with potential transformers contained within the cubicles. This equipment has exceeded its normal 25-30 year design life, is obsolete with parts becoming increasingly challenging to procure, is difficult to maintain and does not meet current code and safety standards. These MCCs are at the end-of-life and would require replacement for continued reliable operation.

The DC system includes a C-CAN battery charger and Absolyte batteries, both of which are less than 10 years old and in good condition. However, the system also includes the originally installed Westinghouse DC breakers that are now obsolete and in need of replacement. Additionally, to be code compliant, the battery room needs to be configured to provide proper ventilation of the sealed batteries. Although sealed batteries emit less hydrogen gas than vented lead-acid batteries, small amounts are still released and must be safely vented in accordance with standards such as CSA C22.1 Rule 26-506 and IEEE Std 1187.

The protection relays at the station are a combination of digital type relays and obsolete mechanical relays. The digital relays include a Schneider PowerLogics ION7550 digital wattmeter and a Basler Auto-Synchronizer PRS-210, both of which are obsolete. Westinghouse and GE mechanical relays are still in use for generator protection, are obsolete and are subject to decreased reliability and would require modernization to ensure continued reliable operation. The protection relays for the substation are also a combination of obsolete mechanical relays and newer digital relays which are in fair condition.



Figure 2-9: Greenhill Generator and Substation Protection Relays

Several AC and DC motors from various manufacturers are in use, all of which are original to the installation in 1975. It is recommended that electrical testing be conducted to assess their condition and operational status and determine whether replacement would be necessary. The DC starting system was upgraded by Alba Power in 2012 and is in good condition.

The Cummins GGKC-5566945 auxiliary power unit (600 V/140 kWe) is in reasonably good condition and has no noted reliability issues. The propane tank serving this unit is in poor condition and should be replaced. The Cummins PowerCommand transfer switch appears to be in good condition and is equipped with relatively new Siemens disconnect switches and has no noted reliability or operational issues.



Figure 2-10: Greenhill Auxiliary Power Unit and Propane Tank

2.4 Greenhill Controls and Instrumentation

Greenhill's protection and control systems were upgraded in 2003 including the addition of a digital governor control system, fuel control module and a Bentley Nevada accelerometer-based vibration monitoring system. The Bentley Nevada system is now obsolete with parts difficult to source. The upgraded control package is based on the standard Allen Bradley ControlLogix PLC technology. The human machine interface (HMI) is an Allen Bradley ControlLogix and is viewed on an Allen Bradley Panelview 1000 screen. These systems are obsolete and the increasing difficulty in sourcing replacement parts is elevating reliability risks. As such, they would require replacement for continued reliable operation.

2.5 Greenhill Buildings

The buildings are original to the Greenhill plant and show signs of aging and have widespread corrosion. The building envelope has deteriorated and both the GG and PT enclosures show significant corrosion damage. The service building is similarly affected, with NP staff advising of roof leaks. Although the turbine air intake was refurbished in 2002, there is now substantial corrosion visible on its exterior face. The main building exhibits signs of corrosion and interior and exterior cladding deterioration and is considered to be in fair condition.

In 1995, the inertial filter system was removed from the air intake due to deterioration and was replaced with fabric filters. The air intake generally is in fair condition but requires maintenance due to corrosion deterioration. The exhaust stack was replaced in 2003 and includes snow doors. The exhaust stack is in good condition.

A separate building houses the generator switchgear, instrument transformers and surge protection equipment. Although this structure is original to the CTG installation, it is in fair condition.

The fuel forwarding building is in poor condition.



Figure 2-11: Greenhill Building Deterioration



Figure 2-12: CTG Enclosure, Air Intake and Exhaust Stack

2.6 Condition Index Rating Greenhill CTG

The Greenhill CTG condition assessment has been summarized in Table 2-1.

Table 2-1: Condition Assessment: Greenhill CTG

Component	CI (1-10)	Weight	Score	Comment
Gas Generator	Fair - 4	0.25	1.0	
Power Turbine	Poor - 1	0.25	0.25	Casing cracking issue
Clutch	Fair - 4	0.10	0.4	
Generator	Poor - 2	0.25	0.5	Unit at "end-of-life" & needs rewind; issue with stress-corrosion cracking of rotor retaining rings
Building/Exhaust/Intake	Fair - 5	0.05	0.25	Buildings are in fair condition, exhaust stack is in good condition, intake is in fair condition.
Fuel System	Fair - 5	0.05	0.25	Piping in poor condition. Two tanks in fair condition
Electrical/P&C/Batteries	Fair - 5	0.05	0.25	Obsolete and nearing "end-of-life".
Unit Index	**2.9**			
Unit Condition	**Poor**			

The Greenhill CTG is in overall poor condition with continued deterioration. Due to the poor condition of many critical systems, and the lack of vendor support, retirement is recommended in the next 1 - 3 years

3 Wesleyville CTG

3.1 Wesleyville Gas Generator, Power Turbine, Electrical Generator and Auxiliary systems

The Wesleyville CTG Power Plant was originally installed in Salt Pond, Burin in 1969 and was relocated to Wesleyville in 2003/2004. This relocation included significant upgrades to the balance of plant, including a new building to accommodate the equipment. The plant consists of a single RR Avon Mark 1533-52L gas generator, an Associated Electrical Industries (AEI) size B AP1 power turbine, and an AEI speed reduction gearbox, driving a 1200 RPM AEI generator. This unit is not equipped with the necessary components to operate as a synchronous condenser. The unit is fired with liquid fuel (diesel) and does not utilize any form of emission controls or NOx abatement systems.



Figure 3-1: Wesleyville CTG Power Plant

3.1.1 Gas Generator

In 2005, due to its poor condition, the original RR Avon gas generator was replaced by Premier Turbines with another Avon 1533 zero-hour rated refurbished unit of similar vintage and rating. Approximately 1200 industrial Avon units were manufactured, with a number of units still in operation globally. They are mainly used for mechanical drives at gas compression stations in Canada. An upgraded variant of the industrial Avon gas generator remains in production. Maintenance support for the Avon gas generator remains available from a number of sources.

A major overhaul was completed in 2014 following a front bearing failure. Overall, the present gas generator is in fair condition. Although this version of the Avon unit is no longer manufactured by Rolls Royce, spare parts are available from the OEM (now Siemens) and from third party vendors. During a boroscope inspection in 2022, Alba Power classified the unit as being in satisfactory condition and recommended a number of remedial repairs. Additional in-depth inspection of the intake plenum and intake of the GT was recommended, as well as continual boroscope monitoring of an internal oil leak and the entire GT assembly.

Sulzer Turbo Services completed an additional boroscope inspection in 2024 and classified the unit as being in fair condition, except for the #7 discharge nozzle that was found with a significant crack. The unit was removed from service and repaired by Sulzer at their Texas facility in late 2024. The unit is now back at Wesleyville.

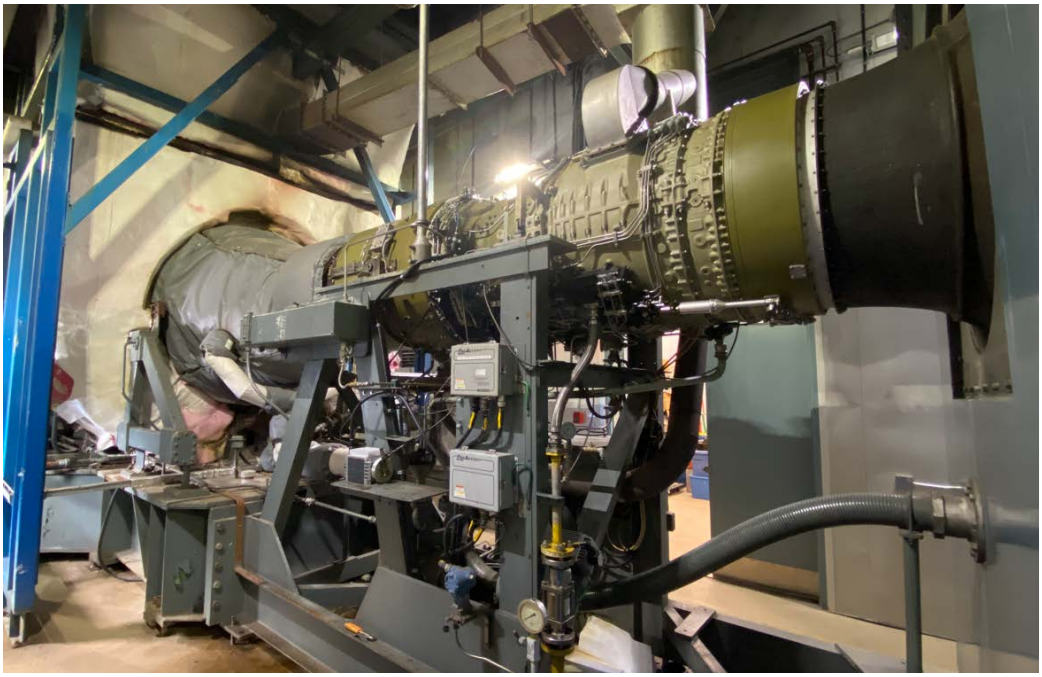


Figure 3-2: Wesleyville Gas Generator and Power Turbine

3.1.2 Power Turbine

An inspection of the PT, also completed in 2014, revealed foreign object damage to the stationary nozzle blades and that the rotor disc had pitting around the blade root area. Cracking of the inlet duct was repaired in the same year. The oil pump and PT bearing were refurbished in 2016.

In 2020, an inspection of the PT was completed and found corrosion on the PT inlet cone and PT disc and cracking was observed in the welds of 15 stator vanes. Alba Power reviewed the findings and advised that while the cracking does not pose an immediate concern, a more detailed inspection should be conducted within 12 months to determine whether overhaul or repair is required to ensure the long-term integrity of the assembly. The PT rotor disc space experiences elevated temperatures due to

exhaust gas leakage around the shaft seal and, as a result, the PT inboard bearing (closest to the power turbine) experiences high temperatures. The high temperatures limit the unit's operation time, as shut down is required to prevent damage when temperature thresholds are exceeded.

The Wesleyville CTG was taken out of service in late 2025, due to rusting and deterioration of the power turbine exhaust volute. This failure was repaired by cutting access openings and patching the bottom of the exhaust volute from the inside. The exhaust is in overall poor condition.



Figure 3-3: Wesleyville Power Turbine Exhaust Volute Repairs

3.1.3 Gearbox

Following the relocation of the CTG unit from Salt Pond to Wesleyville, the gearbox experienced high vibration levels resulting in the unit being derated from 14.7 MW to 8 MW to remain within acceptable operating limits. The elevated vibration is attributed to gear damage caused by circulating eddy currents due to poor gearbox insulating material, which led to erosion and pitting of the gear faces. Upon review, Alba Power recommended the replacement of the gearbox.

3.1.4 Electrical Generator

The generator at the Wesleyville facility is a brushless alternating current generator manufactured by AEI in Great Britain in 1966. Neither the stator nor the rotor have been rewound or reinsulated since installation. The generator is a six-pole Type AG 80/100, 17.7 MVA, 14.15 MW, 13.8 kV, driven at 1,200 RPM via a 4:1 speed reduction gearbox. The power turbine operates at 4,800 RPM. This system is not equipped with a clutch for synchronous condenser operation.

Electrical testing of the generator stator, including power factor (PF) testing, capacitance testing, polarization index (PI) testing, and insulation resistance (IR) testing is conducted regularly by NP personnel. The IR and PI values suggest that the generator, stator and rotor would require refurbishment with a complete rewind. The PI reading was 1.12, which is considered very low and may indicate an issue with the winding insulation.

The unit's instrument transformers and their associated fuses and wiring are in an exposed location near the generator, with a chain link fence barrier. This configuration presents a high risk of arc flash due to the lack of proper enclosures or protective barriers. Stantec recommends that an arc flash assessment be conducted and that arc flash-resistant enclosures and improved protective measures be implemented as per the arc flash assessment to reduce personnel exposure during operation. In the interim, and in accordance with NP's current practice, no personnel are permitted in this area while the machine is running.

In 2014, a new Basler Digital Exciter Control System complete with a new Schneider Digital Metering unit was installed, which operates in conjunction with existing analog meters and switches. The system appears to be in excellent condition and has not experienced any operational issues.



Figure 3-4: Wesleyville Electrical Generator

3.1.5 Auxiliary Systems

The lubrication oil system has also undergone inspection and maintenance activities. The lubrication oil pump's flexible drive coupling membranes showed signs of bowing, although no cracks were detected. While bowing alone is not cause for rejection, the membranes should be regularly inspected for cracking as failure could result in loss of drive to the pump and cause an unplanned outage.

The lube oil cooler was replaced in 2016, and the system is working well. Temperature issues caused by oil remaining in the external cooler during idle periods have been resolved through the implementation of updated start up procedures.



Figure 3-5: Wesleyville Cooling System

3.2 Wesleyville Fuel Oil System

A new fuel storage facility was installed at the Wesleyville site in 2003 and is comprised of two 75,000 litre above ground storage tanks. This provides approximately 33 hours of operation at the derated load of 8 MW (with usable capacity at 90% of installed tank capacity). The tanks are in good condition.

These tanks comply with an older style ULC-S601 specification that have connections on the bottom of the tank. They are acceptable to remain in the current setup, however, as noted for the Greenhill site, if there are major alterations or upgrades to the system these tanks will need to be replaced with new units that have anti-syphon protection with all connections at the top of the tank. New tanks over 80,000 litres, will need to be placed in a secondary containment bermed area, or have tertiary containment as per NFC and CSA B139.1 code requirements.



Figure 3-6: Wesleyville Fuel Oil Storage Tanks

The fuel forwarding system includes a 2003 vintage Woodward Fuel Shutoff Cock Driver and a Woodward Fuel Throttle Valve Driver, both of which continue to support reliable operation. The associated fuel piping is also in good condition, with no major issues reported.



Figure 3-7: Wesleyville Fuel Oil Pumps

3.3 Wesleyville Electrical Systems

The electrical systems are generally in good condition. There is no switchgear in this system. Instead, the output of the generator is directly coupled via a substation breaker to the dedicated step-up transformer, both located in the substation yard.

The high voltage bus work, including potential and current transformers, is exposed in several areas within the building, presenting a potential arc flash hazard. It is recommended that these components be enclosed in an arc flash-rated cabinet and that a complete arc flash assessment be conducted for the facility.

The MCCs are Cutler Hammer Freedom Series 2100, installed in 2004. This lineup is relatively modern, in good condition, and supported by readily available replacement parts.

The station's DC system includes SAFT TPR battery chargers and GNB type batteries. These systems are in good condition. The associated DC distribution panel is a Square-D I-Line Panel with associated DC breakers, which are also in good condition.

All protection relays are digital and were upgraded in 2004. These include an Alstom MiCoM Generation Protection digital relay and a Basler BE1-25A Automatic Synchronizing Relay, both of which are now obsolete.

The DC motors by AEI are in reasonable condition. Further assessment is recommended to determine the suitability of these older motors for continued service.

The auxiliary power system consists of a Kohler Model 65GGHB 65 kW unit, installed in 2003 and fueled by propane from an on-site tank. All equipment appears to be well maintained and in good operational shape, however the propane tank is only in fair condition. The Onan Transfer Switch OT-125, rated at 125 Amps, is in very good condition, along with the associated Siemens disconnect switch and AC panel board.



Figure 3-8: Wesleyville Auxiliary Power Unit and Propane Tank

3.4 Wesleyville Controls and Instrumentation

The control system is a RR Energy Systems Entronic Controls platform, which has been in service for approximately 20 years with continued support from Rolls Royce. The system utilizes Allen Bradley Panel View 1000 HMI with the associated screens and Allen-Bradley ControlLogix hardware. These systems are obsolete with parts being increasingly challenging to procure, resulting in increasing reliability risks, and should be replaced. The controls and instrumentation systems consist of a Bentley Nevada 3500 vibration system which is now obsolete, presenting challenges in sourcing replacement parts and technical support and should be replaced. The majority of the instrumentation is in good condition.

3.5 Wesleyville Building

A new building was constructed in 2003 as part of the unit's relocation to Wesleyville and remains in fair condition. Roof repairs were completed in 2014 but persistent leaks around the exhaust stack to roof transition require occasional repair by NP staff. As part of the relocation, a new filter house air intake system was installed. This system is currently in fair condition, although some areas of corrosion have begun to appear and will require preventative cleaning and re-painting. The exhaust stack was replaced in 2011 and is in fair condition.



Figure 3-9: Wesleyville Building

3.6 Condition Index Rating Wesleyville CTG

The Wesleyville CTG condition assessment has been summarized in Table 3-1.

Table 3-1: Condition Assessment: Wesleyville CTG

Component	C I (1-10)	Weight	Score	Comment
Gas Generator	Fair - 5	0.25	1.25	In fair condition.
Power Turbine / Casing	Poor - 1	0.25	0.25	High temperatures in rotor disc space. Exhaust volute has required patching.
Speed Reduction Gearbox	Poor - 0	0.10	0.0	Persistent vibration following relocation.
Generator	Poor - 2	0.25	0.5	Nearing “end of life”; requires a rewind.
Building/Exhaust/Intake	Fair - 5	0.05	0.25	Building is in fair condition, exhaust stack is in fair condition, intake is in fair condition.
Fuel System	Good - 7	0.05	0.35	Tanks and piping in good condition.
Electrical/P&C/Batteries	Fair - 5	0.05	0.25	Obsolete, near "end-of-life" equipment.
Unit Index	**2.85**			
Unit Condition	**Poor**			

The Wesleyville CTG is in overall poor condition with continued deterioration. Due to the poor condition of many critical systems, and the lack of vendor support, retirement is recommended in the next 1 - 3 years.

4 Grand Bay CTG

4.1 Grand Bay Gas Generator, Power Turbine, Electrical Generator and Auxiliary Systems

The Grand Bay CTG Power Plant consists of a 7 MW Orenda Mobile Electrical Generating Unit Type 318 OT-F-390 Industrial GG coupled with a single-stage PT and a speed reduction gearbox driving a 2-pole (3600 RPM) air-cooled generator. Originally commissioned by Newfoundland Power in 1974, the plant has spent most of its operational life in standby mode. Although initially designed as a mobile unit, it is now installed in a permanent configuration at the Grand Bay substation near Port Aux Basques. This unit is not equipped with the necessary components to operate as a synchronous condenser. The unit is fired with liquid fuel (diesel) and does not utilize any form of emission controls or NOx abatement systems. The gas turbine is in fair condition, with the last refurbishment completed in 2003. Although the CTG is rated at 7 MW, it normally operates closer to 6 MW at 100% fuel flow, likely due to GG deterioration and wear.

4.1.1 Gas Generator

The Orenda combustion turbine generator was originally developed for aircraft applications and later adapted for industrial use with the addition of the single-stage PT and gearbox. Though no longer in production, several Orenda industrial gas turbines are still in operation at various locations.

Parts and service support for the Orenda turbine is limited to third party vendors, principally S&S Turbines in Fort St. John, British Columbia, who acquired 54 Orenda aircraft and industrial engines from Magellan Aerospace (the successor to the OEM). Given the age and rarity of this unit, sourcing spare parts is becoming increasingly difficult. Parts may have to be removed from spare machines and refurbished prior to delivery. A replacement starter, for example, recently took several months to obtain.

The Grand Bay combustion turbine, along with its generator and starting engine, is mounted on a semi-trailer, with a second semi-trailer housing the electrical auxiliaries and power delivery equipment necessary for operation. Power and control cabling connect the two trailers.

4.1.2 Electrical Generator

The generator, manufactured in 1974 by Electric Machinery Manufacturing, is an 8,100 kVA, 12.5 kV, three-phase synchronous machine with a 0.9 power factor and a brushless excitation system. A Philadelphia gearbox is used to reduce the PT output shaft speed from 7,500 RPM to 3,600 RPM.

The original AVR system is at its “end-of-life” with critical parts and components being increasingly challenging to procure due to their obsolescence. This presents expanded reliability risks and operational uncertainty.



The generator undergoes regular maintenance such as lubrication and visual inspection, as well as bi-monthly functional testing from black start. While these practices confirm operational function, they do not extend the unit's service life.



Figure 4-1: Grand Bay CTG Trailer, Auxiliaries Trailer and Unit Transformer

4.1.3 Generator Step-Up Transformer

The generator step-up (GSU) transformer, located on the auxiliary trailer, exhibits significant corrosion, particularly around welds and radiator piping flanges. This corrosion, likely due to the marine environment, poses environmental and operational risks of oil leaks or cooling system failure.



Figure 4-2: Examples of Transformer Corrosion

4.1.4 Semi-Trailer

The semi-trailer supporting the engine and generator is in poor condition with significant corrosion and degradation, is no longer mobile and is installed in a permanent configuration. This deterioration increases the potential of misalignment between the generator, gearbox, and engine as the supporting structure weakens and becomes deformed or damaged. It is recommended that the trailer be refurbished and strengthened or be replaced to avoid damage as a result of the trailer's deteriorating condition. Similar but less severe conditions were observed on the auxiliary trailer, which should have protective coatings renewed to prevent further corrosion and degradation.

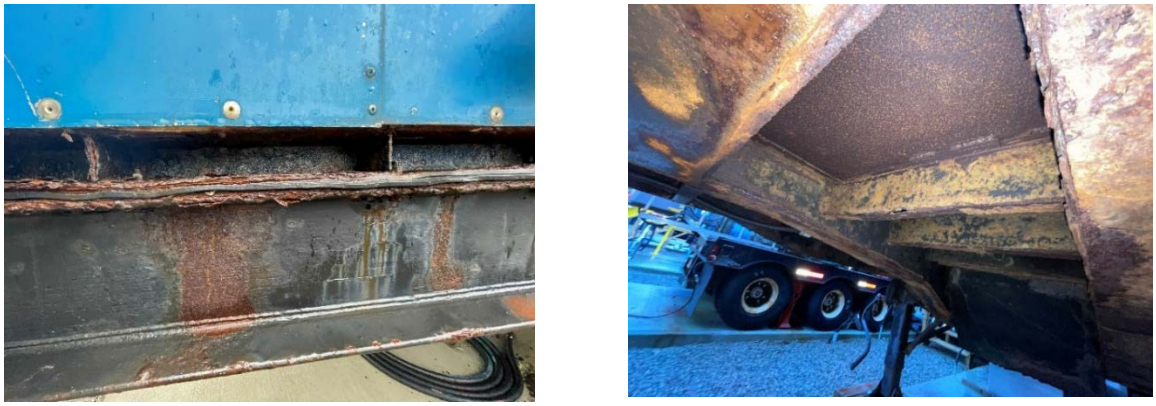


Figure 4-3: Condition of CTG Trailer

4.2 Grand Bay Fuel Oil System

Fuel storage consists of two tanks with capacities of 22,700 litres and 50,000 litres, installed in 2021. With usable capacity at 90% of installed tank capacity, this provides approximately 19 hours of operation at full load. The storage facility and associated piping are in good condition. To ensure continued safe operations and to minimize environmental risks, the system and tanks should be inspected annually and recoated as necessary.



Figure 4-4: Fuel Oil Storage Tanks

4.3 Grand Bay Electrical Systems

The auxiliary electrical systems at the Grand Bay facility were upgraded in 2006 and remain in good condition, having undergone minor repairs and enhancements typical for systems of this age.

The original switchgear equipment, including the generator breaker, is housed in the auxiliary semi-trailer. While still functional and in good condition, the switchgear is at the end of its design life and is obsolete. The installation of electrical equipment within the semi-trailer presents additional challenges due to the custom-built components that fit within the restrictive space confines of the trailer enclosure. Replacement parts would need to be from the OEM, which is increasingly difficult due to the age and limited availability of components, or be designed and/or purpose built for replacement.

The auxiliary electrical system includes an original Allen-Bradley MCC which, despite its age, remains functional and in good condition, due to its limited usage, with replacement parts readily available for this equipment.

Several low-voltage distribution panels are housed within the auxiliaries' semi-trailer, some of which are newer and not original to the installation. These panels were noted to be in good condition, and their replacement or renewal parts are easily obtainable.

The cable tray system throughout the auxiliaries' semi-trailer is in good condition and does not require replacement or upgrades. The DC control power is also located within the auxiliaries' semi-trailer and features a newer C-CAN battery charger and battery system. This system is in good condition; however the auxiliaries' semi-trailer lacks a dedicated and code compliant ventilation system for the batteries, which is required to ventilate hydrogen off-gas from the batteries. Guidance on ventilation requirements is outlined in CSA Standard C22.1, Rule 26-506, and IEEE Standard 1187.

The generator protective relays were upgraded from electromechanical to digital in 2006 and are housed in a cabinet located in the auxiliaries' semi-trailer. These relays include the Alstom MiCOM P343 protection relay, the Basler BE1-25A Auto-Synchronizer and the Schneider PowerLogic ION7550 digital multimeter, all of which are now obsolete.

The auxiliary power unit's exterior enclosure has deteriorated due to exposure to the marine environment, raising concerns about the long-term durability and protection of internal components. Despite this, exterior high voltage cabling that interfaces between the generator and the auxiliary trailer remains in good condition.

4.4 Grand Bay Controls and Instrumentation

The control systems, upgraded in 2006, use Allen Bradley ControlLogix PLC technology. All HMI screens are viewed on a VersaView 1500. This system is in good condition but is obsolete. Replacement parts would be challenging to find in the event of a component failure. Without a functional control system, the generator would not be able to operate.



4.5 Condition Index Rating Grand Bay CTG

The Grand Bay CTG condition assessment has been summarized in Table 4-1.

Table 4-1: Condition Assessment: Grand Bay CTG

Component	C I (1-10)	Weight	Score	Comment
Gas Generator	Fair – 4	0.25	1.0	Unit Obsolete, limited support, but in fair running condition.
Power Turbine	Fair – 4	0.25	1.0	Unit Obsolete, limited support, but in fair running condition.
Speed Reduction Gearbox	Fair – 4	0.10	0.4	In fair condition.
Generator	Poor - 2	0.25	0.5	Unit at "end-of-life" & GSU in poor condition.
Building/Exhaust/Intake	Poor – 1	0.05	0.05	Semi-trailers in poor condition, enclosures in poor condition, intake and exhaust in fair condition.
Fuel System	Good – 7	0.05	0.35	New Fuel Tanks in 2021
Electrical/P&C/Batteries	Fair – 4	0.05	0.2	Obsolete and "end-of-life" equipment.
Unit Index	**3.5**			
Unit Condition	**Fair**			

The Grand Bay CTG is in fair condition but continues to deteriorate. It is no longer mobile and the trailers are in very poor condition. Due to the poor condition of many critical systems and the lack of vendor support, retirement is recommended in the next 3 - 5 years.

5 Port Aux Basques DEG

5.1 Port Aux Basques Diesel Engine and Auxiliary Systems

The Port aux Basques DEG Power Plant consists of a 2.5 MW L-20-C Electrical Generating Unit from General Motors' Electromotive Division. It features a 3660 hp diesel engine directly coupled to an eight-pole, 900 RPM air-cooled synchronous generator. The engine lacks emission controls or NOx reduction mechanisms. The power plant was manufactured in 1969. It has been on standby for most of its operating life. This unit is not equipped with the necessary components to operate as a synchronous condenser.

The Port aux Basques DEG is a modular unit with the diesel engine and generator housed in a dedicated container. Electrical auxiliaries, including power delivery equipment (e.g. switchgear, controls, relays, etc.), are in a separate building and connected to the DEG via underground cables.

The engine is a General Motors EMD Model 20-645-E4, 20-cylinder, 2-stroke diesel engine. Though obsolete, the engine performs well and requires a minimum of maintenance.

The generator, manufactured by General Motors' Electromotive Division in 1969, is a 3,250 kVA, 4.16 kV, three-phase synchronous machine with a 0.8 power factor. It is equipped with a brushed excitation system and is driven by a gearbox that reduces the diesel engine's output shaft speed from 3,600 RPM to 900 RPM to accommodate the generator's 8-pole stator.

Routine maintenance activities, including lubrication, visual inspections, and grid connection testing, are performed regularly on the generator. While this approach ensures the unit's functionality, it does not extend the unit's service life.



Figure 5-1: Switchgear and Auxiliary Equipment for the Port aux Basques Generator



Figure 5-2: Port aux Basques Modularized Generator

The auxiliary electrical systems, including distribution panels, battery system, and switchgear, are in good condition and still functional. With the exception of the modern GE Ion electric power meter, this equipment appears to be the original to the unit. Given the typical design life of 15-30 years, the original equipment is at end-of-life. As such, it is recommended that the protection and control (P&C) devices and generator's controls be replaced with modern digital devices for continued reliable operation.

The excitation system, including the AVR and brushed exciter, is also original and at the end of design life. Replacement is recommended, as sourcing parts for this obsolete system would be difficult in the event of failure. Additionally, as seen in Figure 28, debris from corrosion was observed falling into the exciter circuitry above the alternator, posing a risk of short-circuiting or overheating, which indicates that the exciter is in poor condition. If the unit continues to be operated, the debris should be removed and the ceiling repaired to mitigate this risk.



Figure 5-3: PAB Exciter Circuits and Ceiling

The generating plant's equipment has been in service for approximately fifty years operating as a standby unit. Based on visual inspection the equipment appears to be in good condition with no evident damage or evidence of overheating to the engine and generator's major components.



Figure 5-4: PAB Diesel Engine and Example of Coolant Leaks

Coolant leaks were observed around the diesel engine. Despite replacing the gaskets in the coolant system several years ago, occasional leaks persist as evidenced by absorbent pads and containers placed under leaks. The external condition of the radiator coolant loop piping, as shown in Figure 13, is corroded and in poor condition, suggesting continued/existing leak issues which should be addressed.



Figure 5-5: Example Image of Coolant Piping in Poor Condition

Significant corrosion was observed on the exterior of the DEG's container, likely due to its installation in a marine environment and as a result, the exterior of the unit is rated as being in poor condition. Without mitigation, this corrosion will reduce the service life of the facility and potentially negatively impact reliability as the integrity declines. Refer to Figure 31 for exterior views of the unit.



Figure 5-6: Exterior of PAB Generating Unit



Figure 5-7: Exterior of PAB Generating Unit

NP operational personnel reported that the electronic governor, which controls the diesel engine's speed, does not allow the machine to exceed 58 Hz in islanded mode. It is recommended that this system (governor control system and mechanical components) be further investigated to address these issues and mitigate potential issues related to the unit's ability to synchronize to the local distribution network (60 Hz). As a result of this issue, the electronic governor has been assessed to be in poor condition.

5.2 Port Aux Basques Fuel Oil System

The fuel storage facility consists of one 22,700 litre above ground storage tank which, with usable capacity at 90% of installed tank capacity, can provide approximately 26 hours of operation at full load. The paint coating on the fuel tank is in good condition but requires some touch-ups. There is also some minor denting in the side of the tank with the platform. The tank meets current requirements for fuel storage and is in reasonable condition for continued use in the current system. The fuel oil piping is in good condition but is showing deterioration of the coating system.



Figure 5-8: Fuel Oil Tank and Piping

5.3 Port Aux Basques Electrical Systems

Most of the original electrical equipment of the Port aux Basques DEG remains in service. Minor repairs and upgrades were observed, which are typical for a system of this age. The switchgear, including the generator breaker, is housed in the auxiliary building and is original to the installation. Although the equipment remains operational and in fair condition, it is considered obsolete and at end-of-life. If any components fail, replacement parts would be challenging to source and could require procurement from retail markets.

The protective relays are located in the instrument compartment of the switchgear and consist of discrete Westinghouse electromechanical relays, which are obsolete and are subject to decreased reliability and would require modernization to ensure continued reliable operation.

5.4 Port Aux Basques Controls and Instrumentation

The generating unit's control system is original to the installation and consists of an obsolete hardwired analog configuration. In the event of failure, sourcing replacement components or appropriate technical expertise to troubleshoot and repair this analog system will be challenging which would negatively impact reliability and could cause extended outages. To ensure continued reliable operation, it is recommended that the control system be upgraded to a digital PLC based platform, similar to the Allen Bradley ControlLogix System currently in use at the Grand Bay unit. Standardizing control systems across sites would also streamline spare parts inventory and reduce operational complexity for personnel.

5.5 Port Aux Basques Building

The Port aux Basques generating equipment includes a control/warehouse building which was assessed to be in poor condition. The infrastructure and state of the building were noted to be at end-of-life.



Figure 5-9: Ceiling of Warehouse Area of Auxiliary Building

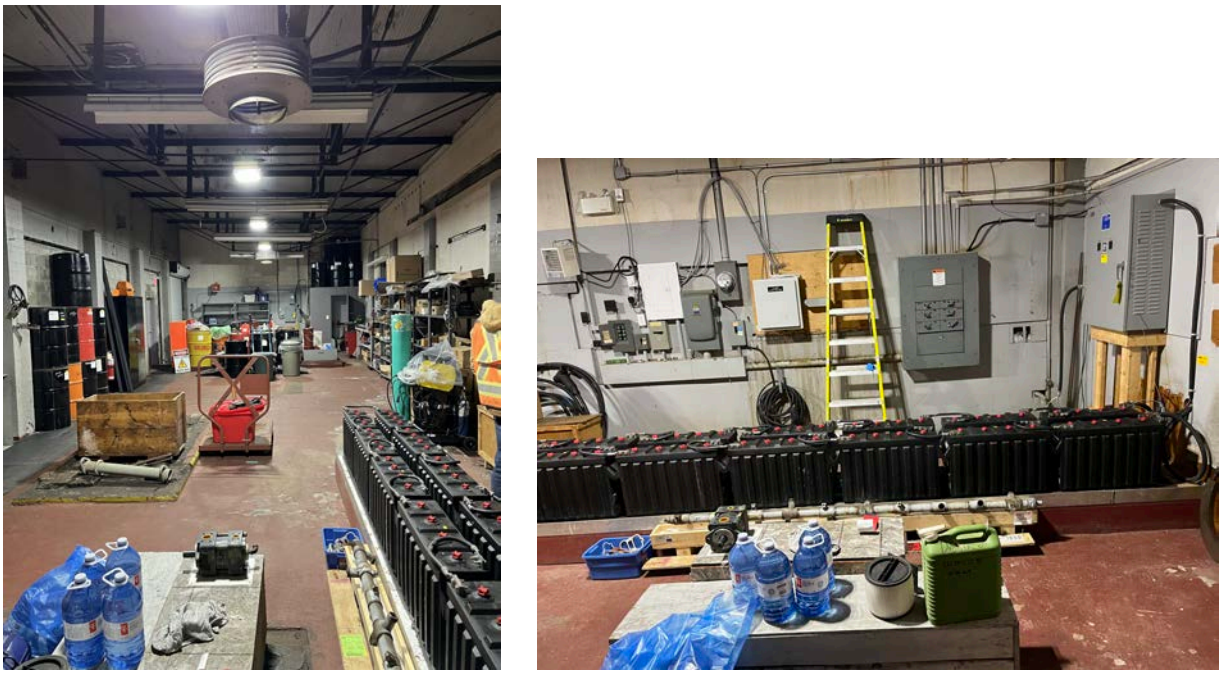


Figure 5-10: Batteries in Warehouse Area of Auxiliary Building

The battery banks for the generating unit are stored in the warehouse area of the building, which lacks forced air ventilation. It is recommended to add forced air and hydrogen monitoring for these battery banks. Guidance on ventilation requirements is provided by standards CSA Std C22.1, Rule 26-506, and IEEE Std. 1187.

5.6 Condition Index Rating Port Aux Basques DEG

The Port aux Basques DEG condition assessment has been summarized in Table 5-1:

Table 5-1: Condition Assessment: Port aux Basques DEG

Component	CI (1-10)	Weight	Score	Comment
Engine	Fair - 4	0.35	1.4	Engine good but cooling system in poor condition / exterior rust.
Generator	Poor - 2	0.35	0.7	Exciter in poor condition / unit at "end-of-life".
Building/Exhaust/Intake	Poor - 2	0.10	0.2	DEG Container and Auxiliary Building in poor condition.
Fuel System	Good - 7	0.10	0.7	Tank and piping in good condition.
Electrical/P&C/Batteries	Poor - 2	0.10	0.2	Equipment is at "end-of-life", obsolete and issues with electronic governor
Unit Index	**3.2**			
Unit Condition	**Fair**			

The Port aux Basques DEG is in fair condition but continues to deteriorate. Due to the poor condition of many critical systems and the lack of vendor support, retirement is recommended in the next 3 - 5 years.

6 Conclusions

Newfoundland Power's stationary thermal generation units, which includes three liquid fueled CTGs and one stationary DEG, were originally purchased in the 1969-1975 timeframe. The age and condition of the equipment and infrastructure, and the lack of OEM support, create expanded reliability risks and operational uncertainty. As a result, NP should commence plans to retire the units.

6.1 Greenhill CTG

The Greenhill CTG facility has reached the end of its service life. This creates expanded reliability risks and operational uncertainty. The gas generator, power turbine, and generator systems, all of which were commissioned in 1975, have undergone multiple overhauls and repairs but continue to exhibit critical age-related degradation. Additionally, the gas generator is no longer supported by the OEM, and parts availability is limited to third party vendors.

The power turbine has experienced persistent casing and shroud cracking, which has resulted in the permanent de-rating of the unit and has caused ongoing reliability concerns. The generator's rotor retaining rings are also susceptible to stress-corrosion cracking, and the excitation system is obsolete. In addition, the fuel oil piping is in poor condition and requires replacement. Much of the original electric infrastructure is outdated, no longer meets modern safety standards and is reaching the end of its serviceable life. Furthermore, the unit's control and instrumentation systems, although partially upgraded, rely on outdated HMI components. The physical condition of the plant buildings reflects the facility's advancing age, displaying widespread corrosion, structural deterioration, and inadequate protection from environmental elements.

The Greenhill CTG is in overall poor condition with continued deterioration. Due to the poor condition of many critical systems and the lack of vendor support, retirement is recommended in the next 1 - 3 years.

6.2 Wesleyville CTG

The Wesleyville CTG facility has reached the end of its service life. This creates expanded reliability risks and operational uncertainty. While the gas generator remains in fair condition, the overall system has experienced significant degradation. The power turbine is exhibiting persistent high-temperature issues and structural concerns, including vane cracking and rotor disk pitting.

The gearbox has elevated vibration levels resulting in permanent de-rating of the unit to 8 MW, a nearly 50% reduction from original 14.7 MW generating capacity. High power turbine inboard bearing temperatures due to seal leakage limit the unit's operating time. Additionally, the generator has not been rewound or reinsulated since being manufactured in 1966 and shows insulation degradation and poor PI readings. This can lead to a high risk of failure without major refurbishment.

The Wesleyville CTG is in overall poor condition with continued deterioration. Due to the poor condition of many critical systems and the lack of vendor support, retirement is recommended in the next 1 - 3 years.

6.3 Grand Bay CTG

The Grand Bay CTG, while ranked in marginally fair condition, continues to deteriorate and is nearing the end of its service life. This creates expanded reliability risks and operational uncertainty.

The Grand Bay semi-trailer which houses the CTG is in poor structural condition and requires significant refurbishment. The auxiliaries' semi-trailer requires repainting, to limit further corrosion, and lacks a dedicated and code compliant ventilation system for the batteries. The Grand Bay generator step-up (GSU) transformer located on the auxiliary trailer exhibits significant corrosion, particularly around welds and radiator piping flanges.

The Grand Bay CGT is in marginally fair condition with continued deterioration. Due to the poor condition of many critical systems and the lack of vendor support, retirement is recommended in the next 3 – 5 years.

6.4 Port Aux Basques DEG

The Port aux Basques DEG, while ranked in marginally fair condition, continues to deteriorate and is nearing the end of its service life. This creates expanded reliability risks and operational uncertainty.

The building and DEG container are in poor condition due to significant corrosion. Electrical, protection and control systems are obsolete and at end-of-life, with the analog control system and electromechanical relays presenting major reliability risks and limited parts availability. Although the engine itself remains in fair condition, cooling system corrosion and persistent leaks require ongoing attention.

The Port aux Basques DEG is in marginally fair condition with continued deterioration. Due to the poor condition of many critical systems and the lack of vendor support, retirement is recommended in the next 3 – 5 years.

Stantec

Stantec is a global leader in sustainable architecture, engineering, and environmental consulting. The diverse perspectives of our partners and interested parties drive us to think beyond what's previously been done on critical issues like climate change, digital transformation, and future-proofing our cities and infrastructure. We innovate at the intersection of community, creativity, and client relationships to advance communities everywhere, so that together we can redefine what's possible.



APPENDIX B:

WES and GRH Thermal Facility Historical Capital Upgrades

Table B-1 Wesleyville Thermal Facility Historical Capital Upgrades (2006-2025)		
Year	Cost ($000s)	Activity
2006	67	Lube Oil Cooling System Refurbishment, Fuel System Refurbishment
2008	289	Gas Generator Refurbishment
2009	112	Turbine Room Ventilation Upgrades
2011	149	Exhaust Stack Partial Replacement, Sump Pit Chamber Refurbishment, Metering Upgrade
2013	20	Power Turbine Insulating Blanket Replacement, Controls Upgrades
2014	1,340	Gas Generator Refurbishment, Power Turbine Refurbishment, Lubricating Oil Cooler Replacement, Building Refurbishment
2015	182	Power Turbine Lube Oil System Upgrade
2016	256	Power Turbine Lube Oil System Upgrade, Power Turbine Bearing Refurbishment
2017	94	Lube Oil System Upgrade, Power Turbine Bearing Refurbishment
2018	128	Gas Generator High Pressure Fuel Pump Replacement, Lube Oil Cooler Gasket Replacement
2019	60	Gas Generator High Pressure Fuel Pump Replacement, Lube Oil Cooler Gasket Replacement, Igniter Pack Overhaul, Fuel Return Actuator Replacement
2020	9	Gas Generator Vibration Probe Replacement, Fuel Shutoff Valve Control Refurbishment
2021	19	Gas Generator High Pressure Fuel Line Replacement, Lighting Upgrades, Security Upgrades
2023	72	Exhaust Volute & Stack Insulation Replacement, Roof Repairs, Power Turbine Insulating Blanket Replacement, Lubricating Oil Pump Refurbishment
2024	143	Combustion Chamber Refurbishment, Security Upgrades
2025	237	Combustion Chamber Refurbishment, Exhaust Volute Refurbishment
TOTAL:	$3,177	

Table B-2 Greenhill Thermal Facility Historical Capital Upgrades (2006-2025)		
Year	Cost ($000s)	Activity
2006	73	Lube Oil Cooler Replacement
2007	24	Lube Oil Cooler Replacement
2008	1	Grounding Upgrade
2009	42	Air Intake Refurbishment, Fire Suppression System Upgrades, Fuel Monitoring System Refurbishment
2010	107	Air Intake Refurbishment, Fire Suppression System Upgrades
2011	30	Metering Upgrade, Fuel System Refurbishment
2012	75	Gas Generator Starting System Upgrade, Battery Bank & Charger Replacement
2014	392	Additional Fuel Storage Tank, Power Turbine Insulating Blanket Replacement, Air Intake Refurbishment
2015	36	Fuel Monitoring System Refurbishment, Building Refurbishment
2016	1,091	Gas Generator Overhaul, Enclosure Refurbishment, Fuel Monitoring System Upgrades, Monorail Crane Refurbishment, Exhaust Stack Refurbishment, Air Intake Refurbishment, Fire Control Panel Upgrades
2019	6	Auxiliary Power Unit Transfer Switch Refurbishment
2020	7	Vibration Probe Replacement
2021	23	Fire Suppression System Refurbishment, Vibration Probe Replacement
2022	57	Fire Suppression System Refurbishment, Exhaust Stack Refurbishment
2023	18	Fuel Pump Refurbishment, Power Turbine Insulating Blanket Replacement
2024	16	Enclosure Refurbishment
2025	8	Exhaust Stack Snow Hood Valve Replacement, HMI Upgrade
TOTAL:	$2,006	

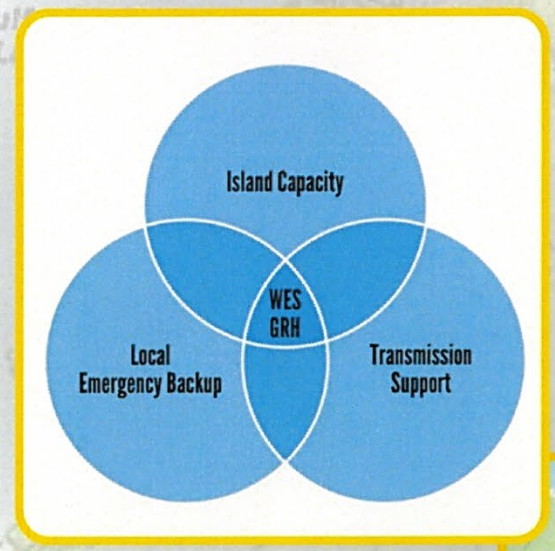
APPENDIX C:

Wesleyville & Greenhill Planning Study

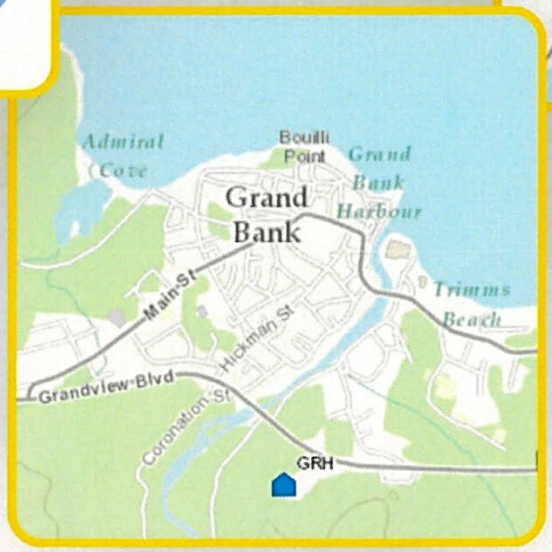
2027

Wesleyville & Greenhill Planning Study

October 2026







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NEWFOUNDLAND POWER
A FORTIS COMPANY

EXECUTIVE SUMMARY

The existing combustion turbine generators ("CTGs") at Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") Wesleyville ("WES") and Greenhill ("GRH") thermal generation facilities have reached the end of their service lives. The *Wesleyville & Greenhill Planning Study* (the "Study") assessed the long-term system requirements associated with retirement of the existing CTGs and evaluated whether replacement generation should be installed at the existing sites or whether the functions currently provided by the facilities should be addressed through other system investments. The assessment considered three principal system functions: (i) local reliability support; (ii) regional transmission-system support in Central Newfoundland, Bonavista Bay, and on the Burin Peninsula; and (iii) firm, dispatchable capacity on the Island Interconnected System ("IIS").

The contribution of each facility differs by location. The WES facility provides transmission-system support in Central Newfoundland and local reliability support to customers supplied by the Gambo–Wesleyville 66 kV transmission system. The GRH facility provides transmission voltage support and local reliability support on the Burin Peninsula, particularly during contingencies affecting the principal transmission lines supplying the area. Retirement of the WES and GRH facilities without replacement generation would also remove firm, dispatchable capacity from the IIS at a time when additional capacity on the IIS is required.

The Study evaluated two long-term alternatives. Alternative 1 would refurbish the WES and GRH facilities by retiring and removing the existing CTGs and installing new sources of firm, dispatchable generation at the existing sites.[1] This alternative would provide approximately 15 MW of firm, dispatchable capacity at WES and approximately 30 MW at GRH, together with synchronous system support, including the capability to operate in synchronous condenser mode. This alternative also includes a new 230/138 kV, 125 MVA transformer at Newfoundland and Labrador Hydro's ("Hydro") Stony Brook Terminal Station and provision for up to 45 MVAR of aggregate reactive power support at Hydro's Bottom Waters and Glenwood Terminal Stations.

Alternative 2 would retire the WES and GRH facilities without installing replacement generation at the existing sites and would address the resulting capacity, transmission-support, and local-reliability requirements through other system investments. This alternative would require additional firm, dispatchable capacity elsewhere on the IIS, additional transformer upgrades and reactive power support, transmission reconfiguration on the Burin Peninsula, and a new 66 kV transmission line between Gambo and Wesleyville to maintain local reliability support.

Alternative 1 is recommended as the preferred long-term planning solution because it has the lowest NPV of the viable alternatives, estimated at $292.6 million compared with $368.9 million for Alternative 2, and remains least cost under the sensitivities examined. The alternative would install approximately 15 MW of firm, dispatchable generation at WES and approximately 30 MW at GRH, maintain local reliability and regional transmission-system support, increase firm capacity on the IIS, and reduce the additional reactive-power infrastructure required in the Study Area. The replacement generation could also operate in synchronous condenser mode,

[1] For the purposes of this Study, 'facility refurbishment' refers to the retirement and removal of the existing combustion turbine generating equipment and the installation of new capacity and associated balance-of-plant, building, electrical, protection, control, and substation assets at the existing sites.

providing reactive power and voltage regulation without combustion-related fuel consumption for most of the contingency and load conditions evaluated.

The combined estimated cost of the proposed WES and GRH projects is approximately $242.1 million, comprising $86.4 million for WES and $155.7 million for GRH, with expenditures planned from 2027 through 2031.

Newfoundland Power should proceed with development of the WES and GRH projects and continue coordinating with Hydro on other system planning requirements in the Study Area including the timing of any potential large industrial load additions, transformer capacity, and reactive-power support. In the near term, Newfoundland Power should continue to maintain the existing WES and GRH facilities for contingency support, subject to their condition, safe operability, and equipment availability. Furthermore, Newfoundland Power should relocate Mobile Generating Unit 2 to Gander so that it can provide contingency support in Central Newfoundland until the permanent solution is in service.

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1.0 INTRODUCTION

The Island Interconnected System ("IIS") is operated jointly by Newfoundland Power Inc. ("Newfoundland Power" or the "Company") and Newfoundland and Labrador Hydro ("Hydro"). Newfoundland Power is the primary distribution utility on the IIS, while Hydro is the primary generation utility. The generation, transmission, and distribution facilities owned by both utilities are fully interconnected and provide reliable electrical service to customers throughout the IIS.[2] As a result, system reliability, capacity adequacy, and the efficient development of electrical infrastructure are shared responsibilities that require ongoing coordination between the utilities. This coordinated planning approach is intended to ensure that customers receive electricity at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service in accordance with the provincial power policy.[3]

The Wesleyville & Greenhill Planning Study (the "Study") was undertaken to determine the long-term system requirements associated with the retirement of Newfoundland Power's existing combustion turbine generators ("CTGs") at the Wesleyville ("WES") and Greenhill ("GRH") thermal generation facilities. The Study assesses whether generation continues to be required at these locations to provide three principal system functions: (i) local reliability support; (ii) regional transmission system support; and (iii) firm, dispatchable capacity on the IIS.

Figure 1 illustrates the three principal system functions provided by the WES and GRH facilities.

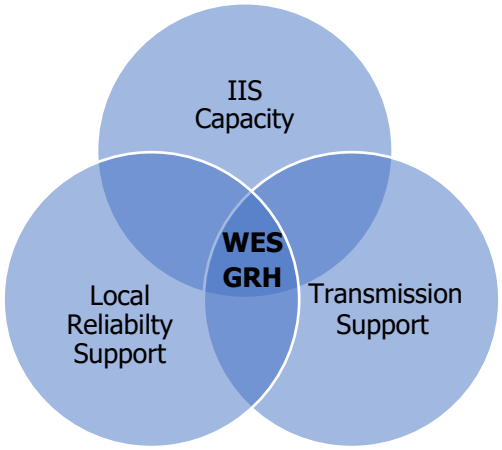


Figure 1 - Wesleyville & Greenhill Combustion Turbine Functions

[2] Newfoundland Power purchases the majority of its energy requirements (93%) from Hydro while the remaining 7% is generated by Newfoundland Power, primarily through its 23 hydro plants located throughout its service territory. In addition, Newfoundland Power owns and operates 6 thermal generating facilities in rural areas of its service territory which provide local reliability support, transmission support, and firm, dispatchable capacity to the IIS. Hydro is also responsible for the 230 kV transmission system on the IIS. Both Hydro and Newfoundland Power have interconnected 66 kV and 138 kV transmission lines on the IIS to enable delivery of electricity to customers.

[3] *Electrical Power Control Act, 1994*, Section 3.(b)(iii).

The Study evaluates two long-term alternatives for the WES and GRH facilities: (i) refurbishing the facilities by replacing the existing CTGs with new firm, dispatchable generation at the existing sites; or (ii) retiring the facilities without installing replacement generation at those sites and addressing the resulting capacity, transmission-system support, and local-reliability requirements through other generation, transmission, and system investments.

2.0 BACKGROUND

The Study Area encompasses Central Newfoundland, the Bonavista Bay area and the Burin Peninsula. The principal 138 kV transmission system through Central Newfoundland extends between Hydro's Stony Brook ("STB" or "STY") and Sunnyside ("SSD" or "SUN") terminal stations and includes transmission lines operated by both Newfoundland Power and Hydro.[4] The transmission system also provides supply to the Bonavista Bay area and the Burin Peninsula. In total, the Study Area serves approximately 70,000 Newfoundland Power customers through 40 substations, as well as approximately 1,800 rural Hydro customers.

Figure 2 illustrates the Study Area.

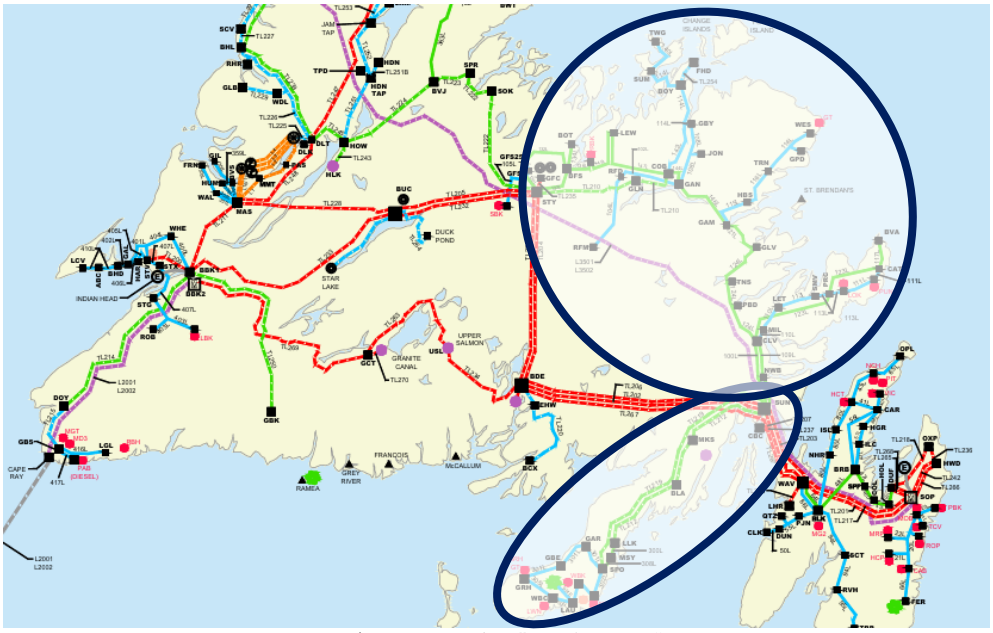


Figure 2 – The "Study Area"

The WES and GRH facilities perform different but complementary functions within the Study Area. WES provides transmission-system support in Central Newfoundland and local reliability support to customers supplied by the Gambo–Wesleyville 66 kV transmission system. GRH provides transmission voltage support and local reliability support on the Burin Peninsula, particularly during contingencies affecting the principal 138 kV transmission lines supplying the area. Both facilities also contribute firm, dispatchable capacity to the IIS.

[4] See Attachment A for a complete list of acronyms for Hydro's terminal stations and Newfoundland Power's substations, and an enlarged map of the Study Area.

From a transmission system perspective, the WES and GRH facilities provide real and reactive power capability that can mitigate voltage violations and transformer loading concerns under certain contingency conditions. Newfoundland Power assesses these requirements through transmission planning assessments ("Loop Assessments") completed in coordination with Hydro and the Newfoundland and Labrador System Operator ("NLSO").[5] These Loop Assessments evaluate transmission-system performance under forecast peak-load and equipment-outage conditions. Newfoundland Power's most recent Loop Assessment is included as Attachment B to the Study.

From a local-reliability perspective, WES has historically provided generation support to rural customers supplied by the Gambo–Wesleyville 66 kV transmission system, while GRH has provided local support to rural customers supplied by the Burin Peninsula transmission system during contingencies affecting the 138 kV transmission lines supplying the area.

Condition assessments completed by a third-party engineering consultant determined that the WES and GRH facilities are in poor overall condition, have reached the end of their service lives, and should be retired. Accordingly, the Study assesses the system requirements that would result from their retirement and evaluates whether these requirements should be addressed through replacement generation at the existing sites or through other generation, transmission and system investments.

The assessment is organized around three planning considerations: (i) firm, dispatchable capacity on the IIS; (ii) regional transmission-system support; and (iii) local reliability support. Section 3 assesses IIS capacity requirements, Section 4 evaluates transmission-system support requirements, Section 5 considers local reliability, and Sections 6 and 7 evaluate the alternatives and identify the recommended long-term planning solution.

3.0 IIS CAPACITY REQUIREMENTS

This section assesses the capacity implications of retiring or refurbishing the WES and GRH facilities in the context of Hydro's ongoing Reliability and Resource Adequacy Study Review (the "RRA Study Review"). It first summarizes the capacity need identified in Hydro's *2024 Resource Adequacy Plan*, then evaluates how the WES and GRH alternatives would affect the amount of firm, dispatchable capacity available on the IIS.[6]

Hydro's resource-planning process considers forecast demand, the capability and performance of existing and planned resources, and future energy and capacity requirements. Hydro has described this process as iterative and has stated that it will continue to reassess load growth,

[5] The NLSO is the entity within Hydro that is responsible for the safe and reliable operation of the bulk electric system in Newfoundland and Labrador and for administering open access to the provincial transmission network. Newfoundland Power's *138 kV & 66 kV Loop Assessments 2027-2036 (Rev 4)*, May 25, 2026 was included in Hydro's *NL Hydro Report – 2026 Annual Planning Assessment (Doc # TP-R-106)*, June 18, 2026 as Attachment B, and was filed with the Board on August 6, 2026. See Hydro's August 6, 2026 letter *Re: Newfoundland and Labrador System Operator Annual Assessments*.

[6] Hydro filed its original *Reliability and Resource Adequacy Study* in 2018. Hydro filed *Reliability and Resource Adequacy Study Updates* in 2019, 2021, 2022, and most recently, Hydro filed its *2024 Resource Adequacy Plan* in 2024.

asset performance, and resource requirements.[7] In its June 30, 2026 Semi-Annual Update, Hydro stated that it plans to submit its next Resource Adequacy Plan in 2027, including an Expansion Plan to meet the Reference Case.[8]

3.1 Hydro's IIS Resource Adequacy Planning

Hydro's 2024 Resource Adequacy Plan identifies a requirement for approximately 525 MW of new IIS capacity by 2034 under its Reference Case.[9] Hydro's 2025 Build Application proposes Bay d'Espoir ("BDE") Unit 8 and the Avalon Combustion Turbine ("Avalon CT"), with approximately 296 MW of combined firm capacity.[10] These proposed additions represent a substantial first step toward meeting the identified requirement, but they do not eliminate the need to consider the capacity contribution of the WES and GRH facilities.

Hydro's resource adequacy planning includes specific analysis of extended outages of the Labrador Island Link ("LIL"). Hydro has stated that the impact of a LIL bipole outage during the winter period would be significant, regardless of duration.[11] Similarly, the Board's consultant, Bates White Economic Consulting ("Bates White") concluded that consideration of an extended LIL Shortfall Analysis is a necessary component of the reliability assessment. In its June 2026 Addendum Report, Bates White stated that "*the LIL Shortfall Analysis is a necessary step given the elevated probability of an extended outage of the LIL during winter weather conditions*."[12]

As part of its *2025 Build Application*, Hydro provided its *Avalon Combustion Turbine Evidentiary Update* (the "Evidentiary Update") which included a 6-week LIL shortfall analysis scenario.[13] For the six-week LIL-outage scenario examined in the Evidentiary Update, the additions of BDE Unit 8 and the Avalon CT continued to show peak generation shortfalls in 2031. The modeled peak shortfalls were 174 MW under the 50th-percentile Slow Electrification case and 266 MW under the corresponding 90th-percentile case.[14]

The January 2-8, 2014, IIS system emergency remains an important reference point when evaluating reliability risks related to generation shortfall on the IIS.[15] During the 2014 event, Newfoundland Power implemented rotating customer power outages on five occasions over the week-long period. The maximum customer load curtailed by Newfoundland Power during the period was approximately 100 MW. Power disruptions during the period resulted in the closure

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7 See Hydro's *Reliability and Resource Adequacy Study Review – 2024 Resource Adequacy Plan: An Update to the Reliability and Resource Adequacy Study, Revision 2: August 28, 2024 – Executive Summary – A Collective Responsibility for Urgent Action-Now and in the Future,* page vii to page ix.

8 See Hydro's June 30, 2026 letter *Re: Reliability and Resource Adequacy Study Review – Semi-Annual Update for the Second Quarter of 2026*, page 7.

9 Ibid, page 2.

10 Ibid.

11 See Hydro's response to Request for Information CA-NLH-007, response to part (c), page 5 filed in relation to Hydro's *2025 Build Application*.

12 See Bates White Economic Consulting, *Expert Addendum Report of Vincent Musco and Collin Cain*, June 5, 2026, page 34, paragraph 81.

13 See Hydro's *2025 Build Application – Avalon Combustion Turbine Evidentiary Update*, April 16, 2026.

14 Ibid, page 8, Table 5.

15 During the January 2-8, 2014, period, Newfoundland Power rotated power due to severe weather and capacity related issues including the unavailability of capacity at the Holyrood Thermal Generating Station ("Holyrood TGS"). See the Board's, *Phase One Report: Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System*, September 29, 2016, page i.

of schools, post-secondary institutions, and numerous public facilities and businesses during a period of severe cold. Hydro's LIL Shortfall Analysis indicates that material generation shortfalls could remain during the modeled prolonged winter LIL outage even with BDE Unit 8 and the Avalon CT in service. Together with the experience of the January 2014 emergency, this supports the need for additional firm, dispatchable resources as part of ongoing IIS resource planning.[16]

Hydro's expansion-planning analysis provides more direct evidence of the capacity value of WES and GRH.[17] The Evidentiary Update modeled increased capacity at the two facilities and selected the uprated Newfoundland Power CTGs in addition to BDE Unit 8 and the Avalon CT under the Reference Case scenarios examined. Hydro stated:

> *"Under reference case scenarios with expected load growth, both BDE Unit 8 and the Avalon CT are selected in addition to the uprated Newfoundland Power CTs, and additional CT resources are selected in 2034, regardless of whether fuel burn-off is considered or when the fuel burn-off requirement is removed."*[18]

The reliability value of available thermal generation was demonstrated during the January 21–26, 2026 frazil-ice event at Hydro's BDE Generating Station. During the event, thermal generation resources across the IIS were dispatched to support system reliability, Newfoundland Power's Curtailable Service Option customers curtailed load, and Hydro and Newfoundland Power issued a Power Warning asking customers to conserve electricity and prepare for the possibility of rotating outages.[19] The event provides a recent example of the operational measures required when a major source of IIS generation becomes unavailable during winter conditions.

Taken together, Hydro's Reference Case results, its expansion-planning treatment of the uprated Newfoundland Power CTGs, the modeled consequences of an extended LIL outage, and recent experience with a significant generation outage on the IIS, support refurbishing the WES and GRH facilities. The appropriate capacity, location, technology, and cost of the replacement resources are evaluated in Section 6.

3.2 IIS Capacity Implications of WES and GRH Retirement or Refurbishment

For this Study, the existing WES and GRH facilities are treated as providing approximately 28 MW of combined generation capability, consisting of 8 MW at WES and 20 MW at GRH. Retiring the facilities without replacement generation would remove that capability from the IIS. The proposed facility refurbishments would provide approximately 15 MW of firm, dispatchable capacity at WES and approximately 30 MW at GRH. Together, the projects would provide approximately 45 MW of firm, dispatchable capacity on the IIS, approximately 17 MW more than the existing combined derated capability of the facilities.

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16 See The Public Utilities Board of Newfoundland and Labradors' *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System, Reports of the Liberty Consulting Group – December 17, 2014*.

17 See Hydro's *2025 Build Application – Avalon Combustion Turbine Evidentiary Update*, April 16, 2026, page 13.

18 *Ibid.*, lines 2-5.

19 See Hydro's report *Frazil Ice at Bay d'Espoir Hydroelectric Generating Station*, filed with the Board on April 30, 2026.

The proposed WES and GRH refurbishments would complement, rather than replace or defer, Hydro's BDE Unit 8 and the Avalon CT projects. Refurbishment would provide approximately 45 MW of firm, dispatchable capacity at the existing sites. It would also preserve the transmission-support and local-reliability functions evaluated in Sections 4 and 5. Accordingly, the capacity contribution of WES and GRH should be evaluated as one component of the generation resources required to meet IIS capacity and reliability needs.

3.3 Avalon Transmission Deliverability

Assessment of additional IIS generation requires consideration of both resource adequacy and transmission deliverability. This distinction is particularly relevant during a LIL outage, when increased transfers over the Bay d'Espoir–Soldiers Pond 230 kV corridor may be needed to serve Avalon demand. Because Muskrat Falls power is delivered to Soldiers Pond via the LIL, an unplanned LIL outage requires the Avalon Peninsula to be supplied by other generation sources located off the peninsula.[20] Hydro considered these transmission constraints as part of its *2025 Build Application*, including the ability to deliver additional power from Bay d'Espoir to the Avalon Peninsula during a LIL outage.[21]

Hydro has evaluated two principal approaches to address thermal constraints on the Bay d'Espoir–Soldiers Pond corridor: (i) implementation of the Avalon Remedial Action Scheme ("Avalon RAS"), together with potential application of Dynamic Line Rating technology; and (ii) reinforcement of the 230 kV transmission system, including a potential third transmission line between Hydro's Western Avalon and Soldiers Pond terminal stations.[22]

Hydro's consultant, TransGrid Solutions Inc, completed a technical feasibility assessment of the Avalon RAS in 2025. Hydro is currently working with Newfoundland Power on the design and implementation of the Avalon RAS, which is expected to have a materially lower estimated cost than a new 230 kV transmission line.[23] Hydro stated that Phase 2 of the Avalon Reactive Power Study will evaluate alternative generation-expansion scenarios, with particular emphasis on increased off-Avalon generation, to determine the resulting Minimum Avalon Generation and reactive-power compensation requirements.[24]

4.0 TRANSMISSION SYSTEM SUPPORT CONSIDERATIONS

A transmission system is the network of high-voltage transmission lines, substations and transformers used to transfer electricity from generating sources to the areas where it is required to serve customers. Electricity flows through this interconnected network based on the location of generation and customer demand, the configuration of the transmission system and the availability of individual transmission facilities. The amount of electricity that can be reliably transferred through the system is therefore influenced not only by the capacity of individual transmission lines and transformers, but also by the ability to maintain acceptable system voltages as operating conditions change.

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20 See Hydro's *2025 Build Application*, *Schedule 3, Expansion Plan Update – Project Justification, Section 6.3, The Expansion Plan and On-Avalon Transmission Constraints*, pages 48–50 (March 21, 2025).

21 *Ibid.*

22 See Hydro's *Avalon Reactive Power Study (Phase 1) - Overview*, page 3 (July 10, 2026).

23 *Ibid.*

24 *Ibid.*, pages 10-11.

Under normal conditions, electricity can be transferred over multiple transmission paths through the interconnected system. If a transmission line or transformer becomes unavailable, however, power flows are redistributed across the remaining facilities. This can increase loading on other transmission lines or transformers and can result in unacceptable voltage conditions in parts of the system. Transmission planning therefore considers both normal operating conditions and contingency conditions in which individual transmission facilities are assumed to be out of service.

Generation located within the transmission system can also influence how the network performs. Local generation can reduce the amount of electricity that must be transferred into an area over the transmission network and can provide real and reactive power to support system voltage.[25] The location of generation can therefore be important to transmission-system performance, particularly during peak-demand and contingency conditions. The transmission-system support provided by the WES and GRH facilities is assessed in this section by examining system performance with and without the generation available under the forecast conditions considered in the Study.

Transmission system planning is critical to ensure that an electric utility can reliably serve customers as demand and system conditions change. It requires assessment of expected system conditions and a range of contingencies, together with the identification of corrective action plans where applicable performance requirements are not met. This forward-looking process enables system deficiencies to be addressed before they expose the transmission system to unacceptable performance, including instability, cascading or interruption of firm electricity service.

4.1 Transmission System Assessments

Newfoundland Power and Hydro routinely complete transmission system assessments ("Loop Assessments") to evaluate the performance of the companies' 138 kV and 66 kV looped transmission systems under forecast peak-load and contingency conditions. These assessments evaluate equipment-outage scenarios under forecast peak-demand conditions and identify operating measures or capital upgrades that may be required to mitigate customer interruptions, voltage violations, and equipment overloads. The results are shared with Newfoundland Power's and Hydro's power system operators to inform the development of operating procedures and capital upgrades that may be required to mitigate the effects of the contingency scenarios studied.

This section provides a detailed assessment of transmission-system support requirements within the Study Area. The 2027–2036 Loop Assessment provided in Attachment B presents a high-level review of planning violations across Newfoundland Power's and Hydro's looped transmission systems under forecast peak-demand and contingency conditions. The analysis in

[25] Real power, typically measured in MW, is the portion of electrical power that supplies electrical load. Reactive Power is the portion of electrical power that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power, typically measured in MVAR, must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. See North American Electric Reliability Corporation ("NERC"), *Definitions Used in the Rules of Procedure* (June 27, 2024).

this section supplements that assessment by considering the year-by-year effects of planned transmission reconfigurations and by evaluating potential large-load additions as a planning sensitivity. Both assessments were completed in accordance with Hydro's transmission planning criteria.

Hydro's Transmission Planning Criteria

Hydro's transmission planning criteria are provided in *NLSO Standard TP-S-007, Transmission Planning Criteria* ("Hydro's Transmission Planning Criteria"), which defines the acceptable pre- and post-contingency response of the power system for all elements rated 46 kV and above.[26] Hydro's Transmission Planning Criteria states:

> *"The transmission planning process requires the use of computer software to perform power system studies in order to demonstrate that the power system meets planning criteria for the present and future states of the system. When simulations of the power system indicate that the system is not meeting the stated planning criteria, the transmission planning process is used to develop cost effective transmission system enhancements to ensure the system meets the planning criteria. The adherence to stated transmission planning criteria is critical in ensuring a long term reliable transmission system."*[27]

Hydro's Transmission Planning Criteria require looped transmission networks on the IIS to be planned to withstand a single contingency ("N-1") and require adequate power-system studies to demonstrate compliance with that criterion.[28] Under the standard, the ability to withstand a single contingency means that the contingency will not result in a violation of applicable voltage and MVA limits or cause system instability.[29] For steady-state planning purposes, bus voltages are to be maintained between 95% and 105% under normal pre-contingency conditions and between 90% and 110% following contingency or emergency events.[30]

Hydro's Transmission Planning Criteria was used to assess the Central Newfoundland and Burin Peninsula transmission system and the implications associated with the retirement of the WES and GRH CTGs.

Overview of Methodology

CYME power engineering software ("CYME") was used to model load flows under the forecast P90 peak-demand conditions for the Study Area during the 2026–2036 planning period.[31] The 2026–2027 and 2028–2031 cases were based on Newfoundland Power's five-year P90 In-Feed

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26 See *NLSO Standard TP-S-007, Transmission Planning Criteria,* page 4.

27 *Ibid*, page 2.

28 *Ibid,* page 10.

29 *Ibid.*

30 See *NLSO Standard TP-S-007, Transmission Planning Criteria,* pages 9 and 15. On a per-unit ("pu") basis, pre-contingency voltage limits for Hydro and Newfoundland Power transmission lines are 0.95-1.05 pu; post-contingency or emergency limits on transmission lines are 0.90-1.10 pu for Hydro and 0.90-1.06 pu for Newfoundland Power.

31 A load flow analysis is a computer simulation used to determine how electricity flows through a power system and to assess resulting equipment loadings and voltage levels under specified operating conditions. CYME is a power system analysis software tool used for modeling and simulation of electrical networks.

Forecast provided to Hydro in December 2025.[32] The 2032–2036 case was based on Hydro's ten-year P90 forecast of Newfoundland Power customer load because Newfoundland Power's In-Feed Forecast does not extend through the full ten-year planning horizon.[33]

The following subsections identify modeled equipment overloads and transmission-system voltages outside the applicable planning limits under the Study Area P90 load scenarios. Unless otherwise stated, Newfoundland Power's hydroelectric generation in the Study Area was assumed to operate at the output specified for each case. Hydro's proposed BDE Unit 8 and Avalon CT were also modeled as in service. The tables identify the cases in which output from WES, GRH, MG2 Mobile Generator[34], Rattling Brook ("RBK")[35] or Sandy Brook ("SBK")[36] was applied as a contingency-mitigation measure.

Load flows were analyzed for various single outages to transmission lines and system transformers to provide an assessment of potential N-1 contingency scenarios for the Study Area. For transmission lines that have multiple sections separated by switches rather than breakers, the section that resulted in worst-case voltages during contingency was disconnected.[37]

Detailed load flow results are presented for the following periods:

1. **2026-2027**: Represents the system before Newfoundland Power's 138 kV transmission line 148L is placed in service and before 66 kV transmission line 108L is retired.[38] The 148L/108L transmission reconfiguration is expected to be completed before the 2027–2028 winter season.

2. **2028-2031**: Represents the system following completion of the 148L/108L transmission reconfiguration. Because forecast P90 demand is relatively stable during this period, the results reflect the highest modeled demand within the period.

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32 P90 represents a relatively high peak-demand forecast, with a 10% probability that actual peak demand will exceed the forecast value.

33 As part of joint system planning efforts, Newfoundland Power and Hydro meet on a routine basis to review and discuss electrical system modelling results and any discrepancies which may be associated with differing assumptions regarding (i) available and dispatched generation resources, (ii) seasonal power factors and (iii) load forecasts.

34 MG2 Mobile Generator refers to Newfoundland Power's Mobile Gas Turbine 2 which is a 5.5 MW mobile gas turbine that can be mobilized and located throughout Newfoundland Power's service territory.

35 Newfoundland Power's Rattling Brook ("RBK") hydroelectric generating plant is located in Central Newfoundland between the Bishop's Falls and Lewisporte areas. For transmission planning purposes, RBK has a full capacity rating of 14.8 MW.

36 Newfoundland Power's Sandy Brook ("SBK") hydroelectric generating plant is located in Central Newfoundland near the town of Grand Falls-Windsor. For transmission planning purposes, SBK has a full capacity rating of 6.3 MW.

37 This corresponds to the following transmission line sections: 124L between Port Blandford and Clarenville ("CLV") substations; TL-210 between Glenwood ("GLN") Terminal Station and Cobb's Pond ("COB") substation; and TL-212 between Monkstown ("MKS") and Bay L'Argent ("BLA") terminal stations.

38 The 148L project involves the construction of a new 138 kV transmission line and the retirement of the existing 66 kV transmission line 108L. The transmission reconfiguration is expected to be completed before the 2027–2028 winter season. The construction of 148L was approved by the Board in Order No. P.U. 27 (2024).

3. **2032-2036**: Represents the later planning period using the highest modeled P90 demand within the period. Unless a replacement-generation scenario is expressly identified, the existing WES and GRH CTGs are assumed to be unavailable.

Table 1 shows the P90 loads that were modeled in the Study Area as part of the assessment.

Table 1
Study Area P90 Load Forecast[39]

Year	Demand [MW]
2026-2027	359
2028-2031	357
2032-2036	400

[39] Newfoundland Power's In-Feed Forecast provides P90 demands for 26 infeed locations where the Company purchases power from Hydro. The infeed locations that supply the Study Area consist of the following 138 kV busses located in both Hydro's terminal stations and/or Newfoundland Power substations: MKS, BLA, Linton Lake ("LLK"), Salt Pond ("SPO"), STB and SUN. The Study Area is also supplied by power purchased at 66 kV from Element Energy's wind farm in St. Lawrence. Forecasted loads from the adjacent and electrically coupled Deer Lake – STB 138 kV loop are excluded from Table 1.

4.2 2026-2027 Modeling Results

Power system modeling results for transmission contingency scenarios resulting in planning violations for the winter 2026-2027 period are presented in Table 2.

Table 2
Effect of 138 kV Transmission Line Contingency Events
Winter 2026-2027

TL Contingency	System Impact	Mitigation Mechanism Applied	Lowest Voltage Following Mitigation
100L	CLV-GAN Voltage Collapse	Dispatch WES CTG[40]	0.92 pu on 110L
106L	CLV-GAN Voltage Collapse	Dispatch WES CTG[41]	0.92 pu on 110L
109L	CLV-GAN Voltage Collapse	Dispatch WES CTG[42]	0.92 pu on 110L
121L	CLV-GAN Voltage Collapse	Dispatch WES CTG Dispatch GRH CTG	0.94 pu on 146L
124L	CLV-GAN Voltage Collapse	Dispatch WES CTG	0.93 pu on 121L
144L	0.89 pu on 146L	Dispatch WES CTG	0.93 pu on 146L
147L	CLV-GAN Voltage Collapse	Dispatch WES CTG Dispatch GRH CTG	0.94 pu on 110L
TL-210	LEW-GAM Voltage Collapse	Dispatch WES CTG Dispatch GRH CTG RBK/SBK at Max Dispatch MG2 in Gander	0.95 pu on 147L
TL-219	Burin Peninsula Voltage Collapse	Dispatch GRH CTG	0.95 pu on 308L

Table 2 identifies nine transmission-line contingencies that result in voltage collapse or post-contingency undervoltage during forecast peak-demand conditions for the 2026–2027 winter period.[43]

[40] This contingency can also be mitigated by dispatching both MG2 in Gander and the GRH CTG. MG2 was modeled in CYME as being connected to distribution feeder COB-01 at Newfoundland Power's Gander Area Office yard.

[41] *Ibid.*

[42] *Ibid.*

[43] The Institute of Electrical and Electronics Engineers ("IEEE"), states that the main symptoms of voltage collapse are – low voltage profiles, heavy reactive power flows, inadequate reactive support, and heavily loaded systems. The collapse is often precipitated by low-probability single or multiple contingencies. The consequences of collapse often require long system restoration, while large groups of customers are left without supply for extended periods of time. See *Voltage Collapse Mitigation – Report to IEEE Power System Relaying Committee, Prepared by IEEE Power System Relaying Committee, Substation Protection Subcommittee, and Working Group K12.* (December, 1996). Each of the transmission line contingencies identified as resulting in a voltage collapse are those for which CYME was unable to obtain a converged power-flow solution, indicating that the modeled system could not sustain a stable post-contingency voltage profile due, in part, to inadequate reactive power availability on the IIS.

Each contingency in Table 2 requires dispatch of WES, GRH, or both at their existing derated capabilities of 8 MW and 20 MW, respectively. The TL-210 case also requires MG2 in Gander to be dispatched and assumes RBK and SBK are available at their maximum modeled outputs. Without the modeled generation support, the identified contingencies would result in voltage conditions outside the applicable post-contingency planning criteria. Customer load shedding would be required to avoid the associated widespread voltage collapse scenarios.

Table 3 illustrates the number of customers that could be impacted by an outage to avoid widespread voltage collapse scenarios in the Study Area for the Winter 2026-2027 period.

Table 3
Customer Outage Potential
If WES & GRH CTGs are Unavailable
Winter 2026-2027

TL Contingency Area	Customers Interrupted
Central	~7,800
Burin Peninsula	~4,400

As shown in Table 3, if the WES and GRH CTGs are not available for the winter 2026-2027 period, up to 7,800 customers may be interrupted within the Study Area depending on which of the nine modeled transmission-line contingencies occur during peak conditions. To minimize customer interruption potential and considering that the WES and GRH CTGs have reached the end of their service lives, it is therefore recommended that Newfoundland Power's MG2 be stationed within the Study Area for the upcoming winter 2026-2027 period.[44]

In addition to various transmission line contingency events requiring mitigation, previous Loop Assessments have determined the potential for overloads to Hydro's 230/138 kV transformer capacity at its STB and SSD terminal stations.

[44] Dispatching MG2 in Gander is required to mitigate the TL-210 contingency, and can also mitigate the 100L, 106L and 109L contingencies if WES CTG is unavailable, provided that GRH CTG is available.

Table 4 illustrates the results of Hydro's largest 230/138 kV transformer contingency scenarios within the Study Area for the winter 2026-2027 period.

Table 4
Effect of System Transformer Contingency Events
2026-2027 Winter Period

Xfmr Contingency	Rating of Remaining Xfmr	Load on Remaining Xfmr Following Contingency	Mitigation Mechanism Applied	Load on Remaining Xfmr Following Mitigation
SSD-T4	125 MVA	183 MVA[45]	Dispatch WES CTG Dispatch GRH CTG Dispatch MG2 at COB Open 124L at CLV	114 MVA
STB-T1	125 MVA	142 MVA[46]	Dispatch WES CTG Dispatch GRH CTG Dispatch MG2 at COB Open TL-245	117 MVA

As shown in Table 4, overloads to Hydro's 230/138 kV transformers at SSD and STB terminal stations are possible under contingency scenarios. For the SSD transformer contingency, the modeled mitigation consists of dispatching the WES and GRH CTGs and opening transmission line 124L at the Clarenville ("CLV") substation. This reduces loading on the remaining SSD transformer from 183 MVA to 114 MVA. WES or MG2 is also required to maintain acceptable Central Newfoundland voltages with 124L open. In the case of the STB transformer contingency, dispatching WES CTG, GRH CTG and MG2 within the Study Area, as well as opening 138 kV transmission line TL-245 successfully reduces loading on the remaining STB transformer from 142 MVA to 117 MVA.

The 2026–2027 analysis identifies eleven contingency cases with voltage or transformer-loading violations. Under the modeled assumptions, the cases can be brought within the applicable steady-state criteria through specified combinations of WES and GRH dispatch, MG2 dispatch at Gander, maximum available output from RBK and SBK where required, and transmission switching. Accordingly, Newfoundland Power should continue to maintain the existing WES and GRH facilities for contingency support for the 2026-2027 winter, subject to their condition, safe operability, and equipment availability. Furthermore, the relocation of MG2 from the Whitbourne Area Office yard to the Gander Area Office yard should proceed as an interim contingency-support measure.

[45] Without additional reactive power support in Central Newfoundland, a loss of either SSD-T4 or STB-T1 resulted in a voltage collapse scenario where CYME was unable to calculate a solution for the load on the remaining transformer. As a result, the load on the remaining transformer values provided in Table 4 are based on MG2 dispatched at COB.

[46] *Ibid.*

4.3 2028-2031 Modeling Results

Power system modeling results for various transmission contingency scenarios for the 2028-2031 winter periods are presented in Table 5.

Table 5
Effect of 138 kV Transmission Line Contingency Events
2028-2031 Winter Periods

TL Contingency	System Impact	Mitigation Mechanism Applied	Lowest Voltage Following Mitigation
124L	GAN-CLV Voltage Collapse	Dispatch WES CTG or MG2 in Gander	0.93 pu on 121L
137L	LEW-CLV Voltage Collapse	Dispatch WES CTG or MG2 in Gander[47]	0.90 pu on 148L
146L	GAM-CLV Voltage Collapse	Dispatch WES CTG	0.98 pu on 121L
TL-210	LEW-GAM Voltage Collapse	Dispatch WES CTG or MG2 in Gander	0.92 pu on 144L and 147L
TL-212	0.87 pu on 308L	Dispatch GRH CTG	0.95 pu on 308L
TL-219	Burin Peninsula Voltage Collapse	Dispatch GRH CTG	0.91 pu on 308L

Table 5 illustrates that multiple 138 kV transmission line contingency events result in widespread voltage collapse scenarios and post-contingency under-voltages during peak system loading for the 2028-2031 winter periods. Compared to the planning violations expected under transmission line contingency events during the 2026-2027 winter period as outlined in Table 2, fewer violations exist during the 2028-2031 period. This is largely the result of the system improvements associated with the construction of the new 138 kV transmission line 148L from Lewisporte ("LEW") substation to Boyd's Cove ("BOY") substation, which is expected to be constructed and energized in 2027.

Under the modeled assumptions, each contingency in Table 5 can be brought within the applicable post-contingency voltage criteria through the specified dispatch of WES, GRH, or MG2. If the WES and GRH facilities are unavailable and no alternative reactive-power or transmission mitigation is installed, the identified contingencies would still result in voltage collapse scenarios.

Similar to the data previously shown in Table 3, if the WES and GRH CTGs are not available during the 2028-2031 winter periods, up to 7,800 customers within the Study Area may be impacted depending on which of the four modeled transmission-line contingencies occurs during peak conditions. To minimize potential load shedding requirements and considering that the WES and GRH CTGs are approaching end-of-life, it remains recommended that MG2 be stationed at the Gander Area Office yard for the 2028-2031 winter periods.[48]

[47] The mitigation involving MG2 requires boosting STB 138 kV bus to 1.035 pu.
[48] MG2 can mitigate the 124L, 137L and TL-210 contingencies if WES CTG is unavailable.

In addition to various transmission line contingency events requiring mitigation, the potential for overloads to Hydro's 230/138 kV transformer capacity at its STB and SSD terminal stations remains during the winter 2028-2031 period.

Table 6 illustrates the results of Hydro's largest 230/138 kV transformer contingency scenarios within the Study Area for the 2028-2031 winter periods.

Table 6
Effect of System Transformer Contingency Events
2028-2031 Winter Periods

Xfmr Contingency	Rating of Remaining Xfmr	Load on Remaining Xfmr Following Contingency	Mitigation Mechanism Applied	Load on Remaining Xfmr Following Mitigation
SSD-T4	125 MVA	166 MVA	Dispatch WES CTG Dispatch GRH CTG Open 124L	115 MVA
STB-T1	125 MVA	166 MVA	Dispatch WES CTG Dispatch MG2 in Gander Open 144L Open TL-245	122 MVA

As shown in Table 6, overloads to Hydro's 230/138 kV transformers at SSD and STB terminal stations are possible under contingency scenarios. In the case of the SSD transformer contingency, dispatching the WES and GRH CTGs within the Study Area, as well as opening 138 kV transmission line 124L at CLV substation successfully offloads the remaining transformer at SSD terminal station.[49] For the STB transformer contingency, the modeled combination of opening 144L and TL-245 and dispatching WES and MG2 reduces loading on the remaining transformer from 166 MVA to 122 MVA. This result assumes 148L is in service and available and that the required switching and generation resources can be implemented as specified.

The 2028–2031 results show that the identified line and transformer contingencies can be brought within the applicable steady-state criteria using the mitigation combinations specified in Tables 5 and 6. These combinations depend on continued availability of the existing WES and GRH CTGs, MG2 at Gander for designated Central Newfoundland cases, transmission switching, and availability of 148L where noted. Until permanent upgrades are placed in service, Newfoundland Power should continue to maintain the existing WES and GRH facilities for contingency support, subject to their condition, safe operability, and equipment availability. Furthermore, MG2 should remain positioned at Gander as an interim Central Newfoundland support measure.

[49] WES CTG is required to maintain voltages in central Newfoundland with 124L open.

4.4 2032-2036 Modeling Results

Power system modeling results for various transmission contingency scenarios for the 2032-2036 winter periods are presented in Table 7. The 2032–2036 base case assumes that the existing WES and GRH CTGs have been retired and that no replacement generation has been installed at those sites.

Table 7
Effect of 138 kV Transmission Line Contingency Events
2032-2036 Winter Periods

TL Contingency	System Impact	Mitigation Mechanism Applied	Lowest Voltage Following Mitigation
124L	LEW-CLV Voltage Collapse	Not Resolved	Not Resolved
137L	LEW-CLV Voltage Collapse	Not Resolved	Not Resolved
146L	GAN-CLV Voltage Collapse	Not Resolved	Not Resolved
TL-210	LEW-CLV Voltage Collapse	Not Resolved	Not Resolved
TL-212	Burin Peninsula Voltage Collapse	Not Resolved	Not Resolved
TL-219	Burin Peninsula Voltage Collapse	Not Resolved	Not Resolved

Table 7 illustrates that multiple 138 kV transmission line contingency events result in widespread voltage collapse scenarios during peak system loading for the 2032-2036 winter periods if WES and GRH CTGs are no longer in service. Both the WES and GRH CTGs are expected to be retired prior to this timeframe and would therefore be unable to mitigate any of the noted transmission line contingencies. Moreover, it would be impractical to continue to station MG2 in Central Newfoundland as a long-term solution for the Study Area since its purpose is to remain available to supply power to customers in all service areas on the island during extended outages, whether unplanned or planned.[50] As a result, separate system upgrades are required to avoid significant planning violations associated with transmission line contingencies during the 2032-2036 period.

Similar to the 2026-2031 cases, up to 7,800 customers may be impacted to avoid widespread voltage collapse conditions should transmission upgrades not be pursued.

In addition to various transmission line contingency events requiring mitigation, previous Loop Assessments have determined the potential for overloads to Hydro's 230/138 kV transformer capacity at its STB and SSD terminal stations.

[50] See Order No. P.U. 37 (2017), page 7, lines 28-38.

Table 8 illustrates the results of Hydro's largest 230/138 kV transformer contingency scenarios within the Study Area for the winter 2032-2036 period.

Table 8
Effect of System Transformer Contingency Events
2032-2036

Xfmr Contingency	Rating of Remaining Xfmr	Load on Remaining Xfmr Following Contingency	Mitigation Mechanism Applied	Load on Remaining Xfmr Following Mitigation
SSD-T4	125 MVA	186 MVA	Not Resolved	Not Resolved
STB-T1	125 MVA	198 MVA	Not Resolved	Not Resolved

As shown in Table 8, overloads to Hydro's 230/138 kV transformers at SSD and STB terminal stations are possible under contingency scenarios. In the case of the SSD transformer contingency, opening 124L at CLV is no longer possible, as this would result in a widespread voltage collapse scenario if the WES and GRH CTGs are no longer in service. Similarly, for the STB transformer contingency, opening TL-245 and 144L without the WES CTG available results in voltage-collapse conditions and therefore does not provide effective means to offload the transformer. As a result, system upgrades must be pursued to avoid substantial planning violations associated with transformer contingencies during the 2032-2036 period.

Similar to the 2026-2031 winter periods, the results of the contingency analyses for the 2032-2036 winter periods demonstrate significant planning violations that occur under numerous contingency scenarios. Under the stated 2032–2036 assumptions, the existing operating measures examined do not resolve any of the line or transformer contingency violations identified in Tables 7 and 8. A permanent solution must therefore provide both voltage support for the identified transmission-line contingencies and sufficient transformer capacity or offloading capability for the SSD and STB transformer contingencies. Section 6 evaluates the alternative combinations of generation, reactive-power support, transformer additions, and transmission reconfiguration capable of meeting those requirements.

4.5 Sensitivity Analysis: Consideration of Potential Large Load Customers

Newfoundland Power is aware of four potential large-load proponents in the Study Area with interconnection requests under review by Hydro. The associated loads are not included in Newfoundland Power's base In-Feed Forecast and are therefore assessed as a planning sensitivity rather than as committed forecast demand.

Table 9 provides an overview of these large load customers, their proposed location and peak demand, and timing of their request for power.

Table 9
Future Potential Large Load Customers to be Supplied within the Study Area

Customer	Peak Demand [MW]	Location
Customer 1	15	BOT
Customer 2	25	GLN
Customer 3	7	SUN
Customer 4	42	BWT

A separate high-load sensitivity was completed to evaluate transmission performance if all four potential additions, totaling 89 MW, were connected within the Study Area.[51]

2027-2031 Large-Load Sensitivity Results

Revised modeling results for the 2027-2031 period, which include an additional 89 MW of industrial load, are provided below. For this analysis, the assumed large-load additions resulted in a requirement for approximately 45 MVAR of additional reactive-power support, comprising approximately 25 MVAR at GLN and 20 MVAR at BWT.[52]

[51] Page 3 of Hydro's *Technical Note TP-TN-307*, provided in Attachment C, indicates that Customer 1's load includes 10 MW supplied from a new 230 kV transmission line from STB and an additional 5 MW supplied through BOT Substation. Hydro has indicated that Customers 1-4 will be connected, in some capacity, prior to 2032. Approximately 76 MW of additional load is currently expected before 2032, with a further 13 MW anticipated by 2035. Due to uncertainty regarding the timing and capacities of these developments, the sensitivity analysis conservatively assumes that the full 89 MW of additional load materializes prior to 2032.

[52] Reactive power support can be provided in multiple ways including installing shunt capacitor banks, STATCOMs, synchronous condensers, and the associated substation interconnection equipment.

Table 10 illustrates the result of various transmission line contingency events during this scenario.

Table 10 Effect of 138 kV Transmission Line Contingency Events - 2027-2031 Winter Periods Sensitivity: Includes 89 MW of Additional Industrial Load and 45 MVAR of Reactive Power Support			
TL Contingency	System Impact	Mitigation Mechanism Applied	Lowest Voltage Following Mitigation
124L	LEW-CLV Voltage Collapse	Dispatch WES CTG	0.96 pu on Remaining Section of 124L
137L	LEW-CLV Voltage Collapse	Dispatch WES CTG MG2 in Gander	0.91 pu on 148L
146L	GAN-CLV Voltage Collapse	Dispatch WES CTG	0.99 pu on 121L
TL-210	LEW-GAN Voltage Collapse	Dispatch WES CTG MG2 in Gander	0.93 pu on Remaining Section of TL-210
TL-212	Burin Peninsula Voltage Collapse	Dispatch GRH CTG	0.95 pu on Remaining Section of TL-212
TL-219	Burin Peninsula Voltage Collapse	Dispatch GRH CTG	0.93 pu on 308L

As shown in Table 10, if the potential large industrial loads materialize and the assumed additional reactive-power support is installed at BWT and GLN, the specified combinations of WES, GRH, and MG2 bring each modeled transmission-line contingency within the applicable post-contingency voltage criteria. This conclusion applies only with the assumed reactive-power additions in service.

Table 11 presents the 230/138 kV transformer-contingency results for the 2027–2031 large-load sensitivity.

Table 11 Effect of System Transformer Contingency Events 2027-2031 Winter Periods Sensitivity: Includes 89 MW of Additional Industrial Load				
Xfmr Contingency	Rating of Remaining Xfmr	Load on Remaining Xfmr Following Contingency	Mitigation Mechanism Applied	Load on Remaining Xfmr Following Mitigation
SSD-T1	125 MVA	181 MVA	Dispatch WES CTG Dispatch GRH CTG Open 124L	122 MVA
STB-T1	125 MVA	206 MVA	Dispatch WES CTG MG2 in Gander Open 144L Open TL-245	190 MVA

As shown in Table 11, while the identified combination of generation dispatch and transmission switching resolves the SSD transformer contingency, the modeled operating measures do not resolve the STB transformer contingency.

Therefore, the results of both Tables 10 and 11 suggest the following for the 2027-2031 winter periods:

1. 25 MVAR of additional reactive power support may be required for Customer 2's load addition at GLN.

2. 20 MVAR of additional reactive power support may be required for Customer 4's load addition at BWT.

3. Dispatching various combinations of the existing outputs of the WES and GRH CTGs, along with MG2 in Gander, were found to resolve the observed transmission line contingencies, as well as the SSD transformer contingency.

4. None of the operating measures or switching configurations examined in this analysis reduces the remaining STB transformer loading to its applicable planning rating. As a result, STB transformer upgrades are likely required to support the potential large load additions.

2032-2036 Large-Load Sensitivity Results

The 2032–2036 sensitivity assumes that all four potential large-load additions, totaling 89 MW, are in service; the existing WES and GRH CTGs have been retired without replacement; MG2 is no longer located in the Study Area; and 45 MVAR of aggregate reactive-power support is installed at BWT and GLN. Tables 12 and 13 show the remaining line and transformer contingency violations under those assumptions.

Table 12 illustrates the result of various transmission line contingency events during this scenario.

Table 12 Effect of 138 kV Transmission Line Contingency Events 2032-2036 Winter Periods Sensitivity: Includes 89 MW of Additional Industrial Load			
TL Contingency	System Impact	Mitigation Mechanism Applied	Lowest Voltage Following Mitigation
121L	GAN-CLV Voltage Collapse	Not Resolved	Not Resolved
124L	LEW-CLV Voltage Collapse	Not Resolved	Not Resolved
136L	LEW-CLV Voltage Collapse	Not Resolved	Not Resolved
137L	LEW-CLV Voltage Collapse	Not Resolved	Not Resolved
144L	LEW-CLV Voltage Collapse	Not Resolved	Not Resolved
146L	GAN-CLV Voltage Collapse	Not Resolved	Not Resolved
TL-210	LEW-GAN Voltage Collapse	Not Resolved	Not Resolved
TL-212	Burin Peninsula Voltage Collapse	Not Resolved	Not Resolved
TL-219	Burin Peninsula Voltage Collapse	Not Resolved	Not Resolved

Table 13 presents the results of the principal 230/138 kV transformer contingency scenarios for the 2032–2036 winter periods under the large-load sensitivity.

Table 13 Effect of System Transformer Contingency Events 2032-2036 Winter Periods Sensitivity: Includes 89 MW of Additional Industrial Load				
Xfmr Contingency	Rating of Remaining Xfmr	Load on Remaining Xfmr Following Contingency	Mitigation Mechanism Applied	Load on Remaining Xfmr Following Mitigation
SSD-T1[53]	125 MVA	215 MVA	Not Resolved	Not Resolved
STB-T1[54]	125 MVA	256 MVA	Not Resolved	Not Resolved

[53] This transformer contingency also results in a voltage collapse to transmission lines 115L and 116L.
[54] Ibid.

As shown in Tables 12 and 13, if 89 MW of additional load were to materialize prior to 2032 and considering (i) the P90 2036 case; (ii) the existing WES and GRH CTGs are retired; and (iii) MG2 is no longer stationed in the Study Area, there are no mitigation measures available to resolve the various transmission and transformer contingency scenarios that result in voltage collapse or transformer overload scenarios.

The preceding analysis demonstrates that transmission upgrades will be required to address numerous undervoltage issues and transformer overloads within the Study Area, particularly if the WES and GRH CTGs are retired and potential large load additions materialize. Hydro's Technical Note *TP-TN-307*, provided in Attachment C, contains Hydro's analysis of the 2036 P90 large load case with Newfoundland Power's thermal generation retired. Hydro's analysis assumes increased transformation at SSD and STB terminal stations and identifies the requirement for substantial new reactive power support and/or new transmission lines. These requirements will be considered further in the assessment of alternatives in Section 6.

5.0 LOCAL RELIABILITY CONSIDERATIONS

The preceding section assessed the transmission-system support provided by generation at WES and GRH under forecast peak-demand and contingency conditions. This section assesses the local reliability functions provided by the WES and GRH facilities. Section 5.1 considers the Gambo–Wesleyville 66 kV transmission system, where WES has historically supported customers during transmission outages. Section 5.2 considers the Burin Peninsula transmission system, where GRH provides local generation support and operational flexibility during transmission contingencies and planned outages.

5.1 Gambo-Wesleyville 66 kV Transmission System

The Gambo–Wesleyville 66 kV transmission system consists of two radial transmission lines connected in series: (i) Transmission Line 115L, extending from Gambo ("GAM") Substation to Hare Bay ("HBS") Substation, and (ii) Transmission Line 116L, extending from HBS Substation to Wesleyville.[55]

Transmission Line 115L is approximately 21 kilometres long and extends northeast from GAM Substation to HBS Substation. Transmission Line 116L is approximately 62 kilometres long and extends northeast from HBS Substation to supply Trinity ("TRN"), Greenspond ("GPD") and WES substations. Together, transmission lines 115L and 116L form the primary source of supply to all customers downstream of GAM Substation, including HBS, TRN, GPD and WES substations.

[55] Radial transmission systems, which are most common in rural areas with limited transmission lines, correspond to a substation being fed by a single transmission line. Looped transmission systems, which are most common in urban areas with multiple transmission lines, correspond to a substation being fed by two or more transmission lines. An outage to a radial transmission line is more likely to result in an extended customer outage than a looped transmission line because a looped system can often continue to receive supply through an alternate transmission path.

An area map is provided in Figure 3.



Figure 3 - Map of Gambo – Wesleyville 66 kV Transmission Network

Customer counts for substations supplied by the Gambo – Wesleyville 66 kV Transmission System, along with their 5-year load forecasts, are provided in Table 14.

Table 14
Gambo – Wesleyville 66 kV System
Customer Counts & Load Forecast

Substation	Customer Count (December 2025)	Forecasted Demand (2030) [MVA]
HBS	837	4.0
TRN	768	3.9
GPD	258	1.0
WES	1,704	9.6
Subtotal:	**3,567**	**18.5**[56]

[56] Approximately 1.1 MVA of load can be transferred from HBS to GAM during peak events through an existing tie point between distribution feeders HBS-01 and GAM-01. As a result, for contingency scenarios following an outage to transmission line 115L, the forecasted peak demand for the network is 17.4 MVA.

Without generation at the WES substation, an outage to Transmission Line 115L results in an outage to all customers supplied by the HBS, TRN, GPD and WES substations, while an outage to Transmission Line 116L results in an outage to all customers supplied by TRN, GPD and WES substations.[57] Furthermore, as these transmission lines are ultimately supplied by the Central Newfoundland 138 kV Transmission System, outages to various 138 kV lines within the Central Newfoundland transmission system can also result in outages to HBS, TRN, GPD and WES substations.

Table 15 compares the five-year average transmission-supply reliability performance of the Gambo–Wesleyville 66 kV transmission system with the Company average using Transmission Supply System Average Interruption Duration Index ("T-SAIDI") and Transmission Supply System Average Interruption Frequency Index ("T-SAIFI").

Table 15
Gambo – Wesleyville 66 kV System
Transmission Supply Reliability[58]
5-year Average (2021-2025)

System	T-SAIDI	T-SAIFI
HBS-TRN-GPD-WES (Total)	2.88	3.49
Corporate Average (Total):	0.62	0.49

As shown in Table 15, customers supplied by the Gambo–Wesleyville 66 kV Transmission System experience transmission-related outages that are approximately five times longer and seven times more frequent than the Company average.

In 2020, Newfoundland Power completed a preliminary assessment of the reliability of the Gambo–Wesleyville 66 kV transmission system relative to the Company's other radial transmission systems. The assessment reviewed the frequency and duration of unplanned transmission outages from 2011 through 2020 and evaluated the historical contribution of the WES CTG to reducing customer interruptions. For each event in which the WES CTG was dispatched, the assessment estimated the reliability impact that would have occurred if the unit had not been available.

[57] The extent of customer interruption following outages to 115L or 116L may be reduced through manual sectionalizing. There are no transmission line breakers at HBS, TRN or GPD substations; however, switches at these locations can be manually opened to isolate sections of these transmission lines depending on the fault location.

[58] Based on loss of substation supply events caused by outages to the following transmission lines: 115L, 116L, 121L, 124L and 146L. T-SAIDI and T-SAIFI values excluded distribution-related outages specific to distribution feeders.

Table 16 summarizes key reliability indicators for the Gambo–Wesleyville System over the 2011–2020 period, including the contribution of WES CTG to mitigating transmission-related outages.

Table 16
115/116L Transmission Supply Reliability
Adjusted to Reflect WES CTG Unavailability
(2011–2020)

System / Substation	T-SAIDI (Actual)	T-SAIDI (Adj.)	% Increase	T-SAIFI (Actual)	T-SAIFI (Adj.)	% Increase
115L/116L	0.95	2.23	**135%**	0.57	0.85	**49%**
WES	1.08	3.72	**244%**	0.79	1.03	**30%**
Average Radial TL:	1.06			0.45		

As shown in Table 16, the assessment estimated that, without operation of the WES CTG, T-SAIDI for the 115L/116L system would have been approximately 135% higher and T-SAIFI would have been approximately 49% higher over the 2011–2020 period. The results demonstrate that the WES CTG materially reduced the duration and frequency of customer interruptions associated with transmission outages during the period assessed. These findings are consistent with the results presented in Table 15, which indicate a decline in transmission-level reliability to the Gambo–Wesleyville area in recent years as the WES CTG has become progressively less available to respond to outages due to age and condition-related factors.

The historical reliability results demonstrate that customers supplied by the Gambo–Wesleyville 66 kV transmission system have experienced substantially greater exposure to transmission-supply interruptions than the Company average. Because 115L and 116L form a radial supply path, an outage affecting either line can interrupt service to customers served by multiple downstream substations. Operation of the WES CTG has historically reduced the frequency and duration of customer interruptions associated with these outages and has also provided additional flexibility with respect to planned outages.[59] The local reliability function provided by generation at WES should therefore be maintained in the assessment of long-term alternatives.

5.2 Burin Peninsula 138 kV & 66 kV Transmission Systems

The Burin Peninsula transmission system consists of interconnected 138 kV and 66 kV transmission networks. The 66 kV system is supplied from the upstream 138 kV system through a looped network of transmission lines. While this configuration provides alternate supply paths, transmission outages can still interrupt or restrict supply to customers.

The Burin Peninsula transmission system is supplied from Hydro's SUN Terminal Station via 138 kV transmission lines TL-212 and TL-219. Hydro's TL-219 transmission line is approximately 155 kilometres long and directly supplies the SPO substation. TL-212 is approximately 144

[59] During the 2006-2025 period, WES CTG was operated on 28 occasions to provide local support during planned outages.

kilometres long and supplies Monkstown ("MKS"), Bay L'Argent ("BLA") and Linton Lake ("LLK") substations. Newfoundland Power's 138 kV transmission line 300L connects the LLK and Marystown ("MSY") substations, while transmission line 308L connects the MSY substation to the SPO substation, thereby completing the 138 kV loop system.[60]

Newfoundland Power's 138 kV/66 kV transformer at SPO supplies the Burin Peninsula 66 kV loop, which serves the GRH, Garnish ("GAR"), Laurentian ("LAU"), Grand Beach ("GBE"), and Webbers Cove ("WBC") substations. Located at the bottom of the Burin Peninsula, GRH provides a local source of generation within the 66 kV loop to support rural customers during outages affecting the upstream transmission supply.

An area map of the Burin Peninsula 138/66 kV transmission system is provided in Figure 4.

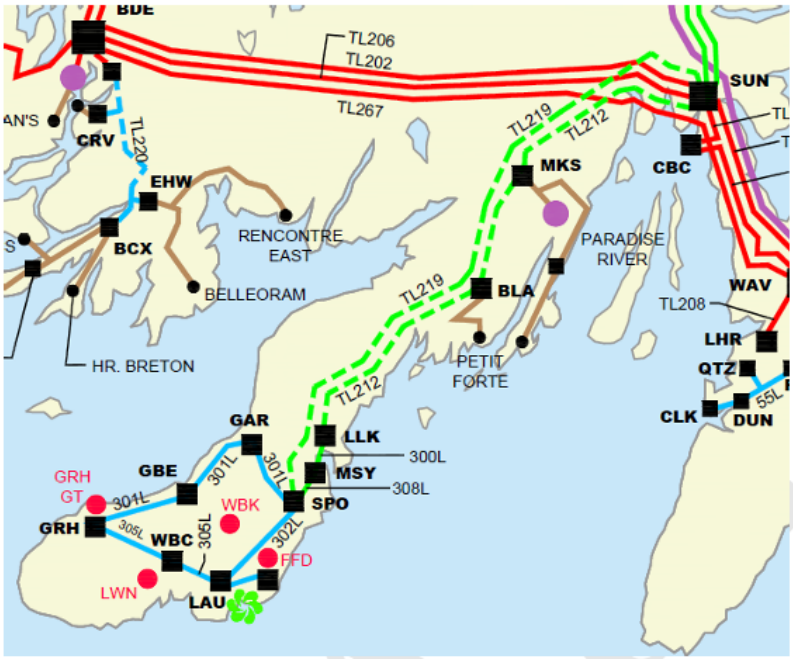


Figure 4 - Map of Burin Peninsula 138/66 kV Transmission System

[60] As of December 2025, there were 7,326 customers supplied by the Burin Peninsula 138 kV loop consisting of the following substations: MKS, BLA, LLK, MSY, SPO. The 2030 forecasted non-coincident peak load for this system is 46.2 MVA.

Customer counts for substations supplied by the Burin Peninsula 66 kV Transmission System, along with their 5-year forecasts, are provided in Table 17.

Table 17
Burin Peninsula 66 kV System
Customer Counts & Load Forecast

Substation	Customer Count (December 2025)	Forecasted Demand (2030) [MVA]
GAR	474	2.5
GBE	105	0.3
GRH	2,291	16.0
WBC	820	4.3
LAU	702	7.1
Total:	4,392	30.2

Because the system is looped, not every transmission-line outage interrupts customers. Customer impacts depend on the location and duration of the outage, available switching arrangements, and the availability of local generation. Forced-outage performance was therefore reviewed for the transmission lines serving the Burin Peninsula, including Hydro-owned TL-212 and TL-219 and Newfoundland Power-owned 300L, 301L, 302L, 305L and 308L. To facilitate comparison between transmission lines with different available data periods, outage statistics were normalized on an annual basis.[61]

[61] Newfoundland Power's current Outage Management System ("OMS") was first implemented in 2019, with complete year-end data first available in 2020. Since the OMS is primarily triggered by outage results to distribution customers and considering that looped transmission line outages may not necessarily trigger incident events in the Company's OMS, further data sources were considered to develop comprehensive forced outage statistics for transmission lines. This includes: (i) reliability data for TL-212 and TL-219 obtained from Hydro, (ii) historical switching orders undertaken on Newfoundland Power's transmission lines, and (iii) historical outage data compiled prior to 2019. As a result, some transmission lines have data available for different periods.

Table 18 summarizes annualized forced outage performance for individual Burin Peninsula transmission lines and provides grouped summaries for the 138 kV loop, 66 kV loop, combined Burin Peninsula transmission system, and corporate average forced outages.

Table 18
Annual Forced Outage Performance of
Burin Peninsula Transmission Line System

Transmission Line System	Avg. Annual Forced Outages	Avg. Annual Forced Outage Hours	Forced Outage Rate [%]
138 kV Loop (2016–2025)[62]	1.63	12.01	0.137
TL-212	0.9	16.32	0.186
TL-219	1.7	25.07	0.286
300L	3.9	6.64	0.076
308L	0.0	0.00	0.000
66 kV Loop (2006–2025)	0.28	0.50	0.006
301L	0.25	0.50	0.006
302L	0.40	0.72	0.008
305L	0.20	0.28	0.003
Corporate Average (2006–2025)	0.50	0.31	0.004

Table 18 shows that the principal exposure to transmission-supply outages is on the upstream 138 kV system. Over the 2016–2025 period, TL-212 and TL-219 contributed the greatest annual forced-outage hours among the lines reviewed. While the 66 kV loop has experienced comparatively few forced outages, it remains dependent on these upstream supply lines.

A replacement GRH facility with approximately 30 MW of generation would be capable of supplying the forecast peak requirement of the Burin Peninsula 66 kV loop. During an outage that interrupts or restricts the upstream supply, generation at GRH could be used to maintain or restore service to customers on the local 66 kV system, subject to the location of the outage and available switching arrangements.

The GRH facilities also provides local reliability support during planned transmission outages. During the 2006–2025 period, the GRH CTG was operated on 34 occasions to provide local support during planned outages. Maintaining generation at GRH would therefore preserve an established source of local reliability support for the 4,392 rural customers served by the GRH, GAR, LAU, GBE and WBC substations during planned and unplanned transmission outages.

6.0 ASSESSMENT OF ALTERNATIVES

Building on the capacity, transmission-system support, and local reliability requirements identified in Sections 3 through 5, this section develops and evaluates two long-term alternatives for meeting those requirements. The alternatives consider whether the required

[62] Hydro outage data for its 138 kV transmission lines TL-212 and TL-219 is not available prior to 2016.

functions should be maintained through refurbishment of the WES and GRH facilities or provided through other generation, transmission, and local reliability investments.
As established in Sections 3 through 5, retirement of the WES and GRH facilities without replacement generation at the existing sites would result in the following system requirements that would have to be addressed through other investments:

1. Replacement of the firm, dispatchable capacity currently provided by WES and GRH.
2. Loss of transmission voltage support in Central Newfoundland and on the Burin Peninsula.
3. Transformer-loading violations at Hydro's STB and SSD terminal stations under contingency conditions.
4. Loss of local reliability support for customers supplied by the Gambo–Wesleyville 66 kV transmission system.
5. Loss of local reliability support and operational flexibility on the Burin Peninsula transmission system.

As discussed in Section 4.5, the Study also considers potential large industrial load additions as a planning sensitivity. The alternatives are therefore developed to address the identified base-system requirements and are further assessed under the higher-load conditions associated with the potential industrial load additions currently under review by Hydro. This approach evaluates whether each alternative addresses the identified base-system requirements and remains technically suitable if the potential large industrial load additions materialize.

6.1 Development of Alternatives

The alternatives were developed to satisfy the following planning requirements identified in Sections 3 through 5:

1. Maintain firm, dispatchable capacity on the IIS.
2. Maintain transmission-system performance within the applicable planning criteria under normal and contingency conditions.
3. Maintain loading on Hydro's system power transformers at the SSD and STB terminal stations within their applicable planning ratings under contingency conditions.
4. Maintain local reliability support for the Gambo–Wesleyville 66 kV transmission system.
5. Maintain local reliability support and operational flexibility on the Burin Peninsula transmission system.

Alternative 1

Alternative 1 would refurbish the WES and GRH facilities by retiring and removing the existing generating equipment and installing one nominal 15 MW CTG at WES and two nominal 15 MW CTGs at GRH, together with the associated fuel, auxiliary power, electrical, protection and control, building, civil, and substation work required to integrate the new units at the existing sites.

The proposed WES facility refurbishment would provide approximately 15 MW of firm, dispatchable capacity. Based on the forecast loads assessed in Section 5.1, this capacity would be sufficient to supply the forecast peak requirements of the TRN, GPD, and WES substations following loss of their transmission supply and approximately 99% of the forecast peak requirements of the broader HBS, TRN, GPD, and WES system. The proposed GRH facility refurbishment would provide approximately 30 MW of firm, dispatchable capacity, sufficient to supply the forecast peak requirement of the Burin Peninsula 66 kV transmission system. Together, the proposed WES and GRH facility refurbishments would provide approximately 45 MW of firm, dispatchable capacity on the IIS, approximately 17 MW more than the existing derated capability of the facilities.

Hydro's analysis in Attachment C, *Technical Note TP-TN-307*, identifies up to 105 MVAR of additional reactive power support in the Study Area if the WES and GRH CTGs are retired. With the proposed WES and GRH facility refurbishments in service, the modeled additional reactive-power requirement is reduced from 105 MVAR to 45 MVAR.[63] Alternative 1 therefore includes 45 MVAR of additional aggregate reactive power support at BWT and GLN.

As further outlined in Attachment C, *Technical Note TP-TN-307*, due to low fault levels in the Study Area, the 45 MVAR of aggregate reactive power support would require 10 discrete stages if a capacitor bank solution was procured.[64] Alternatively, continuous reactive-power devices, such as Static Synchronous Compensators ("STATCOMs"), could be used.[65]

In summary, Alternative 1 would involve:

1. Refurbishing the WES facility by replacing the existing CTG with one nominal 15 MW CTG capable of providing firm, dispatchable capacity and synchronous system support, including operation in synchronous condenser mode. This would provide firm, dispatchable capacity on the IIS, local reliability support for the Gambo–Wesleyville 66 kV transmission system, voltage support in Central Newfoundland, and generation support required to facilitate opening Transmission Line 124L to offload Hydro's SSD transformer during the applicable contingency conditions.

2. Refurbishing the GRH facility by replacing the existing CTG with two nominal 15 MW CTGs capable of providing approximately 30 MW of firm, dispatchable capacity and synchronous system support, including operation in synchronous condenser mode. This would provide firm, dispatchable capacity on the IIS, local reliability and voltage support on the Burin Peninsula, and generation support required to offload Hydro's SSD transformer during the applicable contingency conditions.

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63 The requirement for additional reactive power, up to 45 MVAR, in the Study Area is largely dependent on the extent to which the potential large load customers require electrical service within the study period.

64 A capacitor bank is a group of electrical capacitors connected to the electrical system to supply reactive power, measured in MVAR, and voltage support. At BWT Terminal Station, 20 MVAR is required with a maximum switchable capacitor bank amount of 3 MVAR; therefore 7 stages are required. At GLN Terminal Station, 25 MVAR is required with a maximum switchable capacitor bank amount of 10 MVAR; therefore, 3 stages are required. See page 13 of *Attachment C: Technical Note TP-TN-307.*

65 A STATCOM is a fast, electronically controlled device that supplies reactive power to support transmission-system voltage.

3. Installing a new 230/138 kV, 125 MVA transformer at Hydro's STB Terminal Station. This would resolve Hydro's STB transformer loading violations identified under contingency conditions.

4. A provision to install up to 45 MVAR of new reactive power support at BWT Terminal Station and GLN Substation. This would support the ability of the proposed refurbished generators at WES and GRH substations to resolve Study Area voltage violations should additional large load industrial customers materialize.

Together, these investments satisfy the planning requirements established for the alternatives by providing firm, dispatchable capacity on the IIS, resolving the identified transmission-voltage and transformer-loading violations, and maintaining local reliability support for the Gambo–Wesleyville and Burin Peninsula transmission systems.

Newfoundland Power engaged Sargent & Lundy ("S&L") to assess technically feasible replacement technologies for the WES and GRH CTGs, including new CTGs, reciprocating internal combustion engines, and battery energy storage systems. S&L recommended CTG technology because it can provide firm, dispatchable capacity and synchronous system support, with lower estimated lifecycle costs and less implementation complexity than the other technologies evaluated. Stantec Consulting Ltd subsequently developed site-specific CTG cost estimates for the WES and GRH facilities, which form the basis for the Alternative 1 capital costs as part of the economic analysis presented in this Study.[66]

[66] S&L's analysis is based on individual CTGs having ratings of 15.2 MW, with one CTG installed at WES, and two CTGs installed at GRH.

Capital costs associated with this alternative are provided in Table 19.

Table 19
Alternative 1
2027–2031 Capital Costs ($ Millions)

Activity	2027	2028	2029	2030	2031	Total
WES Refurbishment (15 MW)	24.8	2.1	2.8	25.1	31.6	86.4
GRH Refurbishment (30 MW)	46.4	3.5	6.1	46.7	53.0	155.7
STB Transformer Upgrades (Hydro)[67]	-	0.2	2.3	12.8	-	15.3
Install 20 MVAR, 7-stage Capacitor Bank at BWT (Hydro)[68]	-	-	-	0.8	12.2	13.0
Install 25 MVAR, 3-stage Capacitor Bank at GLN (Hydro)[69]	-	-	-	0.8	12.2	13.0
NP Project Total	71.2	5.6	8.9	71.8	84.6	242.1
Hydro Project Total	-	0.2	2.3	14.4	24.4	41.3
Project Total:	71.2	5.8	11.2	86.2	109.0	283.4

Alternative 2

Alternative 2 would retire the WES and GRH CTGs, addressing the resulting system impacts through the installation of additional firm, dispatchable generation capacity, transmission upgrades, reactive power support, and local reliability improvements. Alternative 2 includes approximately 45 MW of additional firm, dispatchable generation capacity to replace the IIS firm capacity contribution that would otherwise be provided by the replacement generation proposed under Alternative 1.

In the absence of replacement generation at WES and GRH, the transmission analysis identifies a requirement for up to approximately 105 MVAR of additional reactive-power support if reactive power alone is used to address the resulting voltage requirements in the Study Area. As outlined in Attachment C: *Technical Note TP-TN-307*, a reactive power-only solution comprised of capacitor banks may require up to 20 discrete 138 kV capacitor bank stages to avoid voltage flicker.[70] Alternative 2 instead combines 80 MVAR of additional reactive-power support in Central Newfoundland with a transmission reconfiguration on the Burin Peninsula to avoid the 25 MVAR of reactive power that would otherwise be required at SPO.

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67 Hydro's STB transformer costs are based on aggregate SSD and STB upgrade costs, as provided in Hydro's *2027 Capital Budget Application, Five-Year Capital Plan including Major Projects (2027-2031),* Appendix A, page A-12. Correspondence to Newfoundland Power by Hydro included an estimated allocation between the two sites, which was used to approximate the STB transformer cost shown in Table 19.

68 GLN Terminal Station upgrade costs were estimated by Newfoundland Power and used as a proxy for the BWT Terminal Station upgrade costs.

69 GLN Terminal Station upgrade costs were estimated by Newfoundland Power.

70 See page 13 of *Attachment C: Technical Note TP-TN-307.* In addition to the 10 stages required as described in footnote 59, at SPO substation, 25 MVAR is required with a maximum switchable capacitor bank amount of 6 MVAR; therefore 5 stages are required. At GAN substation, 10 MVAR is required with a maximum switchable capacitor bank amount of 10 MVAR; therefore, 1 stage is required.

In 2021, Newfoundland Power engaged Hatch Ltd. to conduct a detailed voltage analysis study of the Burin Peninsula to consider the impacts of retiring the GRH CTG. The Hatch assessment concluded that switched capacitor banks alone would not provide an adequate solution and identified continuous reactive-power support, such as a synchronous condenser or STATCOM at SPO Substation, as the appropriate form of voltage support.[71] However, in Attachment C, *Technical Note TP-TN-307*, Hydro identifies an alternative form of transmission voltage support under contingency scenarios for the Burin Peninsula that was not considered in Hatch's analysis: splitting TL-219 at both MKS and BLA terminal stations. This would require a total of four new 138 kV breakers, or two for each terminal station, as an alternative to procuring 25 MVAR of reactive power support at SPO. Based on the alternatives and cost information considered in the Study, splitting TL-219 at MKS and BLA represents the least-cost technically viable approach evaluated for addressing the Burin Peninsula voltage-support requirement if generation at the GRH facility was not replaced.[72]

Section 5 demonstrates that customers supplied by the Gambo–Wesleyville 66 kV transmission system experience substantially greater exposure to transmission-supply interruptions than the Company average and that operation of the WES CTG has historically reduced customer interruption impacts. Alternative 2 therefore includes a second 66 kV transmission line between GAM and WES substations to maintain local reliability support following retirement of the WES CTG.

Alternative 2 would include:

1. Installing approximately 45 MW of additional firm, dispatchable generation capacity elsewhere on the IIS. This would replace the firm-capacity contribution that would otherwise be provided by the WES and GRH replacement generation included in Alternative 1.

2. Installing a new 230/138 kV, 125 MVA transformer at Hydro's Sunnyside Terminal Station. This would address the SSD transformer-loading violations that would remain following retirement of the WES and GRH CTGs.

3. Installing a new 230/138 kV, 125 MVA transformer at Hydro's Stony Brook Terminal Station. This would address the STB transformer-loading violations identified under contingency conditions.

4. A provision to install up to 80 MVAR of reactive power support at BWT, GLN, GAN, and GAM terminal stations. This would replace and enhance the Central Newfoundland voltage-support function currently provided by the WES CTG and provide the necessary reactive power support should additional large load industrial customers materialize.

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71 See *Attachment D: Hatch Report – Burin Peninsula Voltage Regulation*, page 14.

72 Aggregate costs for modifying BLA and MKS substations were estimated to be approximately $15.3 million. This is largely driven by substantial civil work that would be required at both sites to facilitate the upgrades. Conversely, installing a suitable 25 MVAR STATCOM at SPO substation was estimated to be more than $20 million.

5. Installing two new 138 kV breakers at Monkstown and two new 138 kV breakers at Bay L'Argent, together with the associated TL-219 transmission line tie-ins. This would permit TL-219 to be split and would provide the required Burin Peninsula transmission-voltage support following retirement of the GRH CTG.

6. Constructing a new 66 kV transmission line, approximately 70 km in length, between Gambo and Wesleyville, including new breakers at both substations. This would maintain local reliability support for customers supplied by the Gambo–Wesleyville 66 kV transmission system following retirement of the WES CTG.

Together, these investments would satisfy the planning requirements established for the alternatives by replacing the firm, dispatchable capacity otherwise provided by WES and GRH, resolving the identified transmission-voltage and transformer-loading violations, and maintaining local reliability support for the Gambo–Wesleyville 66 kV transmission system.

Under Alternative 2, the IIS capacity requirement would be addressed through the installation of 45 MW of additional dispatchable capacity, while the remaining transmission and local reliability requirements would be addressed through transformer upgrades, reactive power support, transmission reconfiguration, and a second transmission path supplied by a new transmission line between GAM and WES.

Costs associated with this alternative are provided in Table 20.

Table 20
Alternative 2
2027–2031 Costs ($ Millions)

Activity	2027	2028	2029	2030	2031	Total
New 66 kV Transmission Line from GAM to WES	-	2.0	9.8	9.3	9.4	30.5
New 230/138 kV, 125 MVA Transformer at SSD (Hydro)[73]	-	0.2	2.9	15.7	-	18.8
New 230/138 kV, 125 MVA Transformer at STB (Hydro)[74]	-	0.2	2.3	12.9	-	15.4
BLA Terminal Station Upgrades (Hydro)[75]	-	0.7	6.3	-	-	7.0
MKS Terminal Station Upgrades (Hydro)[76]	-	0.7	7.6	-	-	8.3
Install 25 MVAR, 4-stage Capacitor Bank at GAM	-	-	1.5	7.3	-	8.8
Install 10 MVAR, 1-stage Capacitor Bank at GAN	-	-	0.6	2.9	-	3.5
Install 20 MVAR, 7-stage Capacitor Bank at BWT (Hydro)[77]	-	-	-	0.8	12.2	13.0
Install 25 MVAR, 3-stage Capacitor Bank at GLN (Hydro)[78]	-	-	-	0.8	12.2	13.0
New 66 kV Breakers at GAM and WES	-	-	-	0.6	4.4	5.0
Replacement 45.6 MW Capacity (Hydro's Overnight Cost)[79]	-	-	-	-	261.8	261.8
NP Project Total	-	2.0	11.9	20.1	13.8	47.8
Hydro Project Total	-	1.8	19.1	30.2	286.2	337.3
Project Total:	-	3.8	31.0	50.3	300.0	385.1

[73] Hydro's STB and SSD transformer costs are based on aggregate SSD and STB upgrade costs, as provided in Hydro's *2027 Capital Budget Application, Five-Year Capital Plan including Major Projects (2027-2031),* Appendix A, page A-12. Correspondence to Newfoundland Power by Hydro included an estimated allocation between the two sites, which was used to approximate the individual transformer costs shown in Table 20.

[74] *Ibid.*

[75] Estimated by Newfoundland Power.

[76] *Ibid.*

[77] GLN Terminal Station upgrade costs were estimated by Newfoundland Power and used as a proxy for the BWT Terminal Station upgrade costs.

[78] GLN Terminal Station upgrade costs were estimated by Newfoundland Power.

[79] The estimated cost of the additional 45 MW of capacity on the IIS is $5,126/kW in 2025 dollars and is based on Hydro's report *Hardwoods and Stephenville Life Extension Condition Assessment*, June 15, 2026. See *Section 4.4 Class 5 Cost Estimates*, pages 11–12. The corresponding capital cost provided in Table 20 has been escalated to 2031 dollars, which is $5,741, based on the Signal49 Research GDP deflator, medium term forecast dated February 6, 2026, and long term forecast dated March 27, 2026.

6.2 Evaluation of Alternatives

This section compares the viable alternatives from an economic perspective and confirms through load flow analysis that the least-cost alternative satisfies the identified technical requirements. The evaluation first compares the alternatives using an NPV analysis, including sensitivities related to fuel consumption and other cost considerations, such as the potential for the proposed replacement CTGs at WES and GRH to operate as synchronous condensers for the purpose of providing transmission-level voltage support. The least-cost alternative is then evaluated through load flow analysis to confirm that it addresses the identified transmission-system constraints.

Evaluation of Synchronous Condenser Potential and IIS Fuel Considerations

Synchronous Condenser Potential

For Alternative 1, Newfoundland Power recognizes that fuel consumption could be material if the proposed replacement capacity is operated in advance of winter peak periods to address potential voltage concerns. To better understand these requirements, the analysis also considered whether the proposed CTGs could operate in synchronous condenser mode.[80]

The voltage collapse scenarios identified in Section 4 require the applicable WES and/or GRH facilities to be providing voltage support before the contingency occurs, because starting the CTGs after the contingency would not prevent the initial voltage collapse. CYME was therefore used to determine the minimum Study Area load level at which the Central 138 kV Transmission System becomes exposed to undervoltage violations under relevant contingency conditions. This analysis provides insight into both the value of synchronous condensing capability at the existing WES and GRH sites and the potential fuel requirements to be reflected in the economic evaluation.

[80] Modern combustion turbines equipped with synchronous condenser capability can perform two distinct functions. In generation mode, the turbine combusts fuel to produce real power for the electrical system. In synchronous condenser mode, the generator can provide reactive power and voltage regulation to support the transmission system without combustion-related fuel consumption.

Table 21 shows the results of the voltage analysis with the WES and GRH CTGs operating as synchronous condensers.

Table 21
Synchronous Condenser Analysis
Assumes Additional 45 MVAR of Combined Reactive Power Support at BWT and GLN and 3rd Transformer at STB
and 89 MW of Industrial Load Additions

TL Contingency	Min. Sys. Load with low voltage post-contingency	Percent of P90 2036 Load That Can be Supported	Maximum Reactive Power Output By Unit	Lowest Voltage Observed
121L	92%	100%	9 MVAR at WES	0.99 pu at GAM
124L	85%	100%	9 MVAR at WES	0.96 pu at PBD
136L	90%	100%	9 MVAR at WES	0.92 pu at LEW
137L	84%	94%	8 MVAR at WES 10 MVAR at GRH	0.91 pu at BOY[81]
144L	79%	100%	9 MVAR at WES	0.96 pu at GAN
146L	83%	100%	8 MVAR at WES	0.99 pu at GAN
147L	93%	100%	7 MVAR at WES	0.99 pu at COB
TL-210	84%	100%	8 MVAR at WES	0.94 pu at COB
TL-212	94%	100%	13 MVAR at GRH	0.96 pu at SPO
TL-219	85%	100%	14 MVAR at GRH	0.92 pu at SPO[82]

The analysis demonstrates that synchronous condenser operation of the proposed WES and GRH CTGs is sufficient to maintain acceptable post-contingency voltages at 100% of the forecast 2036 P90 load for nine of the ten transmission-line contingencies evaluated. For the 137L contingency, synchronous condenser operation is sufficient up to 94% of the forecast 2036 P90 load. At higher load levels, real-power output from the proposed WES and GRH CTGs is required. As noted later in this section, the 137L contingency can be fully mitigated at 100% of the P90 2036 load if both WES and GRH are outputting real power.

Accordingly, the replacement CTGs could provide reactive power and voltage regulation in synchronous condenser mode during most relevant high-load conditions. Real-power operation would be required for the 137L contingency when Study Area load exceeds approximately 94% of the forecast 2036 P90 peak. This distinction is reflected in the fuel assumptions used in the economic analysis.

81 Requires STB 138 kV bus at 1.05 pu.
82 Requires SSD 138 kV bus at 1.05 pu.

The load-duration analysis indicates that synchronous condenser availability would principally be required during higher-load periods. Based on the historical load-duration curves assessed by Newfoundland Power, Study Area load exceeds 79% of peak for approximately 218 hours per year and exceeds 94% of peak for approximately 8 hours per year, or on the actual peak day of the year. Newfoundland Power has historically dispatched available generation on system peak days when requested by Hydro. As a result, having all thermal facilities available for the peak day would mitigate a voltage collapse associated with a loss of 137L during a peak scenario. Accordingly, the proposed CTGs could provide the required voltage support in synchronous condenser mode for most high-load conditions, with real-power operation required only for the limited conditions identified by the load flow analysis.

IIS Fuel Considerations

Because Alternative 1 includes CTGs that would operate for local reliability, transmission-system support, and IIS capacity requirements, the economic evaluation includes the associated fuel and operating costs. These costs are not applicable to Alternative 2, which instead relies on transmission system investments to maintain reliability. Based on local reliability considerations provided in Section 5, annual operating-hour assumptions for unplanned transmission outages were developed using historical T-SAIDI data for transmission lines 115L and 116L and forced-outage data for the Burin Peninsula 66 kV transmission system.

Historical operating data indicates that the WES and GRH facilities have been used to support planned transmission outages at Wesleyville and Greenhill. For the revised NPV analysis, fuel requirements were estimated based on expected operation for local reliability support, including planned and unplanned transmission outage conditions, as well as broader system support during peak periods and potential IIS capacity shortfall events.[83]

Newfoundland Power maintains fuel supply arrangements to support the delivery of diesel fuel to its generating facilities as required. In the event operation is expected to exceed the on-site storage capacity, fuel deliveries would be arranged to replenish inventory and support continued operation. Where necessary, additional suppliers could be engaged to help ensure fuel availability during extended operating events or emergency conditions.

The available on-site fuel storage is considered sufficient to support normal operation of the facilities with planned fuel deliveries. Newfoundland Power does not anticipate issues related to fuel supply if the facilities are operating as local reliability support or for regional transmission-system support. Local contingencies such as transmission line outages or transformer failures in the Central Newfoundland and Burin Peninsula areas are likely to occur independently from major or prolonged system contingencies, such as a LIL Shortfall event. Provided the IIS is not responding to major or prolonged system contingency, fuel consumption on the IIS is likely to be low. Accordingly, the Study does not identify local fuel supply as a constraint on the expected operation of the proposed WES and GRH CTGs for local reliability and transmission-system support under normal contingency conditions.

Extended operation during major or prolonged system contingencies may require additional fuel supply measures. Newfoundland Power will continue to coordinate with Hydro and fuel suppliers

[83] Based on these assumptions, WES is forecast to consume fuel for approximately 105 hours per year, and GRH is forecast to consume fuel for approximately 74 hours per year, on average over the life of the assets.

regarding fuel supply requirements and overall contingency planning for such events. Newfoundland Power will support Hydro's fuel supply adequacy analysis to ensure that the fuel requirements of the proposed WES and GRH facilities are considered as part of broader contingency planning for the IIS. Hydro has confirmed that its assessment will consider fuel requirements for all thermal generating sources on the Island, including the proposed facilities.

Economic Evaluation

An NPV analysis of the alternatives presented in Section 6.1 was completed to compare the costs of each alternative over the life of the required capital assets. The analysis considered the expected operational costs of each alternative.[84] The NPV comparison excludes expenditures common to both alternatives because those expenditures do not affect the relative ranking of the alternatives.[85] An overview of additional parameters and assumptions utilized in the NPV calculation is found in Attachment E.

Table 22 provides the results of the NPV analysis.

Table 22
NPV Analysis of Viable Alternatives
Excludes Expenditures Common to Both Alternatives
($ Millions)

Alternative #	NPV
1	292.6
2	368.9

As shown in Table 22, Alternative 1 has the lower NPV and is therefore the least-cost of the viable alternatives evaluated.

NPV Sensitivity Analysis

Additional economic analyses were conducted to consider the impact of additional sensitivities. For example, while the load flow results indicate that the SSD transformer overload contingency is effectively resolved through to 2036, mitigation still requires transmission line switching facilitated by opening Transmission Line 124L. If more operational flexibility is required,

[84] Operating costs reflect fixed and variable operating costs based on consultant estimates, together with estimated fuel costs for expected unit operation. For Hydro's equivalent capacity replacement option, it is assumed this unit would not be operated for any local support purposes, such as for unplanned radial transmission-level outages. As a result, operating hours for Hydro's replacement capacity option in Alternative 2 are assumed to average approximately 46 hours per year. This reflects system peak and capacity shortfall events only. For synchronous condenser operation of Hydro's replacement option, the analysis assumes 476 hours per year, based on the five-year average synchronous condenser operation of Hydro's Holyrood Thermal Generating Station Unit 3. Further NPV assumptions are provided in Attachment E.

[85] Expenditures common to both Alternatives 1 and 2 are: (i) Hydro upgrading transformer capacity at STB terminal station; (ii) Hydro providing additional reactive power support at BWT terminal station; and (iii) Hydro providing additional reactive power support at GLN terminal Station. While projects (ii) and (iii) are expected to be least-cost relative to other transmission line build alternatives proposed in *Technical Note TP-TN-307* provided in Attachment C, uncertainty regarding their final costs does not influence the relative economics of the alternatives, as these costs are excluded from the NPV analysis because they are common to both alternatives.

additional transformation capacity could be added to Hydro's SSD Terminal Station in advance of 2036.[86] As a result, there would be a material increase in the capital costs of Alternative 1.[87]

Similarly, Alternative 2 includes a new 66 kV transmission line between the GAM and WES substations to avoid any further decrease in the reliability of customers served by the 115L-116L Transmission System. If local reliability support for rural customers served by the Wesleyville-Gambo 66 kV system was permitted to decline, there would be a material decrease in the capital costs associated with Alternative 2 since the additional transmission line would not be constructed.

An NPV sensitivity analysis was completed based on adjusted capital and operating costs associated with both alternatives. The results of the revised NPV sensitivity analysis that considers: (i) SSD transformer upgrades included in Alternative 1; and (ii) the GAM-WES transmission line excluded from Alternative 2, are provided in Table 23.

Table 23
Revised NPV Analyses
SSD Upgrades Included in Alternative 1
GAM-WES TL Excluded from Alternative 2
($ Millions)

Alternative #	NPV
1	310.8
2	334.6

As shown in Table 23, Alternative 1 remains the least-cost alternative after simultaneously including additional SSD transformation costs in Alternative 1 and excluding the costs related to the additional transmission line from GAM to WES from Alternative 2.

[86] Under Alternative 1, the SSD transformer contingency can be mitigated through 2036 by dispatching the proposed WES and GRH CTGs and opening Transmission Line 124L at Clarenville to reduce loading on the remaining SSD transformer. This mitigation therefore relies on the availability of the proposed generation and a specific transmission switching configuration. Additional transformation capacity at SSD would reduce reliance on these operating measures and provide greater flexibility in managing the contingency.

[87] Hydro shows upgrades to both SSD and STB in their latest five-year capital plan. See Hydro's *2027 Capital Budget Application, Five-Year Capital Plan including Major Projects (2027-2031),* Appendix A, page A-12.

Technical Load Flow Results

Load flow results for Alternative 1 under the various transmission line contingency scenarios presented in previous sections are provided in Table 24.

Table 24
Alternative 1 – Effect of 138 kV Transmission Line Contingency Events
2032-2036 Winter Periods
Includes Large Load Proponents
Assumes Additional 45 MVAR of Combined Reactive Power Support at BWT and GLN

TL Contingency	System Impact	Mitigation Mechanism Applied	Lowest Voltage Following Mitigation
121L	LEW-CLV Voltage Collapse	New WES CTG (Sync. Cond. 9 MVAR)	0.99 pu at GAM
124L	LEW-CLV Voltage Collapse	New WES CTG (Sync. Cond. 9 MVAR)	0.96 pu at PBD
136L	LEW-CLV Voltage Collapse	New WES CTG (Sync. Cond. 9 MVAR)	0.92 pu at LEW
137L[88]	LEW-CLV Voltage Collapse	New WES CTG (15 MW) New GRH CTG (30 MW)	0.91 pu at BOY
144L	LEW-CLV Voltage Collapse	New WES CTG (Sync. Cond. 9 MVAR)	0.96 pu at GAN
146L	GAN-CLV Voltage Collapse	New WES CTG (Sync. Cond. 9 MVAR)	0.99 pu at GAN
147L	LEW-CLV Voltage Collapse	New WES CTG (Sync. Cond. 7 MVAR)	0.99 pu at COB
TL-210	LEW-CLV Voltage Collapse	New WES CTG (Sync. Cond. 8 MVAR)	0.94 pu at COB
TL-212	Burin Peninsula Voltage Collapse	New GRH CTG (Sync. Cond. 13 MVAR)	0.96 pu at SPO
TL-219[89]	Burin Peninsula Voltage Collapse	New GRH CTG (Sync. Cond. 14 MVAR)	0.92 pu at SPO

[88] STB 138 kV bus set to 1.04 pu.
[89] SSD 138 kV bus set to 1.05 pu.

Load flow results for Alternative 1 under the transformer contingency scenarios presented in previous sections are provided in Table 25.

Table 25
Alternative 1 - Effect of System Transformer Contingency Events
2032-2036 Winter Periods
Includes Large Load Proponents
And a New 125 MVA Transformer at STB
And an Additional 45 MVAR of Combined Reactive Power Support at BWT and GLN

Xfmr Contingency	Rating of Remaining Xfmr	Load on Remaining Xfmr Following Contingency	Mitigation Mechanism Applied	Load on Remaining Xfmr Following Mitigation
SSD-T1	125 MVA	197 MVA	Open 124L New WES CTG (15 MW) New GRH CTG (30 MW)	121 MVA
STB-T1[90]	125 MVA	123 MVA	New XFMR Installed	123 MVA

The load flow results confirm that Alternative 1 satisfies the transmission-system requirements identified in the Study under the 2032–2036 large-load sensitivity. The proposed WES and GRH CTGs, together with the additional 45 MVAR of reactive-power support and the new 230/138 kV, 125 MVA transformer at STB, maintain modeled transmission voltages and transformer loading within the applicable planning criteria for the contingency conditions evaluated. Together with the local reliability and IIS capacity benefits identified earlier in the Study, these results confirm that Alternative 1 satisfies the planning requirements established for the alternatives.

7.0 RECOMMENDATION

Based on the assessment completed in this Study, Alternative 1 is recommended as the least-cost long-term planning solution. The alternative would replace the existing WES and GRH CTGs with one nominal 15 MW CTG at WES and two nominal 15 MW CTGs at GRH, together with the supporting Hydro system upgrades identified in this Study. Alternative 1 has the lowest net present value of the viable alternatives evaluated and satisfies the identified requirements for firm, dispatchable IIS capacity, transmission-system support, transformer capacity under contingency conditions, and local reliability.

The analysis demonstrates that the refurbished WES and GRH facilities would provide both local and system-level reliability benefits. At WES, the refurbished facility would maintain local reliability support for customers supplied by the Gambo–Wesleyville 66 kV transmission system, where transmission-supply reliability has been materially worse than the Company average and operation of the WES CTG has historically reduced customer interruption impacts during transmission outages. At GRH, the refurbished facility would maintain local reliability support and provide transmission-system voltage support on the Burin Peninsula, including during

[90] STB 138 kV bus set to 1.00 pu. Further offload possible if new WES or GRH CTGs are dispatched.

contingencies involving TL-212 and TL-219, which represent key transmission supply paths to the peninsula.

In addition to these local reliability benefits, Alternative 1 would provide approximately 45 MW of firm, dispatchable capacity on the IIS, approximately 17 MW more than the existing derated capability of the WES and GRH facilities. This capacity contribution is relevant to Hydro's ongoing resource adequacy planning which has identified a significant need for new sources of capacity on the IIS. The proposed WES and GRH facility refurbishments would complement, rather than replace or defer, Hydro's proposed BDE Unit 8 and Avalon CT projects and provide an additional 45 MW of firm, dispatchable capacity at the existing WES and GRH sites.

Alternative 1 would also provide operational flexibility by enabling the proposed CTGs to provide real-power output when generation is required and to operate in synchronous condenser mode when reactive power and voltage regulation are required. The synchronous condenser analysis indicates that the proposed facility refurbishments can materially reduce the need to operate as combustion turbines outside of peak conditions, while still providing voltage support during relevant transmission contingency scenarios.

It is therefore recommended that Newfoundland Power proceed with development of Alternative 1, including refurbishment of the WES and GRH facilities with one nominal 15 MW CTG at WES and two nominal 15 MW CTGs at GRH. Newfoundland Power should continue to coordinate with Hydro regarding the supporting Hydro system requirements, including the new transformer at STB, reactive-power support requirements at BWT and GLN, the potential need for additional transformation at SSD, the treatment of potential large industrial load additions considered in the Study, and fuel supply requirements associated with extended IIS contingency events. This coordinated planning approach will help ensure that the preferred solution addresses both Newfoundland Power's local reliability obligations and Hydro's broader transmission and resource adequacy requirements. Until the permanent solution is placed in service, MG2 should be positioned at the Gander Area Office yard as an interim measure to support Central Newfoundland contingency requirements.

Table 26 summarizes Newfoundland Power's estimated capital expenditures for the proposed WES and GRH project scopes.

Table 26
Newfoundland Power's Recommended Capital Project Costs[91]
2027–2031 Capital Costs
($ Millions)

Activity	2027	2028	2029	2030	2031	Total
WES Facility Refurbishment (15 MW)	24.8	2.1	2.8	25.1	31.6	86.4
GRH Facility Refurbishment (30 MW)	46.4	3.5	6.1	46.7	53.0	155.7
Project Total	**71.2**	**5.6**	**8.9**	**71.8**	**84.6**	**242.1**

[91] The selected equipment has a nominal rating of approximately 15 MW. Detailed consultant estimates are based on an equipment rating of 15.2 MW.

Attachment A:

Station Acronyms and Map of Study Area

Table A-1 provides a list of substations and terminal substations in the Study Area.

Table A-1
Substations and Terminal Stations in the Study Area[1]

Acronym(s)	Station Name	Owner / Operator
BFS	Bishop Falls Substation	Newfoundland Power
BLA	Bay L'Argent Terminal Station & Substation	Hydro & Newfoundland Power
BOT	Botwood Substation	Newfoundland Power
BOY	Boyd's Cove Terminal Station & Substation	Hydro & Newfoundland Power
BVA	Bonavista Substation	Newfoundland Power
BWT[2]	Bottom Waters Terminal Station	Hydro
CAT	Catalina Substation	Newfoundland Power
CLV	Clarenville Substation	Newfoundland Power
COB	Cobb's Pond Terminal Station & Substation	Hydro & Newfoundland Power
FPD	Fall Pond Substation	Newfoundland Power
FHD	Farewell Head Terminal Station	Hydro
GAM	Gambo Substation	Newfoundland Power
GAN	Gander Substation	Newfoundland Power
GAR	Garnish Substation	Newfoundland Power
GBE	Grand Beach Substation	Newfoundland Power
GBY	Gander Bay Substation	Newfoundland Power
GFC	Grand Falls Frequency Converter	Hydro
GFS	Grand Falls Substation	Newfoundland Power
GFS25	Grand Falls 25 kV Substation	Newfoundland Power
GLN	Glenwood Terminal Station & Substation	Hydro & Newfoundland Power
GLV	Glovertown Substation	Newfoundland Power
GPD	Greenspond Substation	Newfoundland Power
GRH	Greenhill Substation	Newfoundland Power
HBS	Harebay Substation	Newfoundland Power

1 Newfoundland Power calls its high-voltage transmission facilities "substations", whereas Hydro calls them "terminal stations". Many substations and terminal stations across the IIS contain infrastructure owned by each of the utilities. For example, Hydro's transmission lines may terminate in a terminal station/substation facility that is also used by Newfoundland Power to distribute power to customers in the area.

2 BWT is situated west of the Study Area and is instead part of the adjacent and electrically coupled Deer Lake – STB 138 kV loop. However, due to the magnitude of its corresponding large load proponent, as well as the potential for reactive power support at BWT to influence voltages in the Study Area, it is included in Table A-1.

Acronym(s)	Station Name	Owner / Operator
JON	Jonathan's Pond Substation	Newfoundland Power
LAU	Laurentien Substation	Newfoundland Power
LET	Lethbridge Substation	Newfoundland Power
LEW	Lewisporte Substation	Newfoundland Power
LLK	Linton Lake	Hydro & Newfoundland Power
LOK	Lockston Substation	Newfoundland Power
LWN	Lawn Substation	Newfoundland Power
MIL	Milton Substation	Newfoundland Power
MKS	Monkstown Terminal Station & Substation	Hydro & Newfoundland Power
MSY	Marystown Substation	Newfoundland Power
NWB	Northwest Brook Substation	Newfoundland Power
PBD	Port Blandford Substation	Newfoundland Power
PRC	Princeton Pond Substation	Newfoundland Power
PUN	Port Union Substation	Newfoundland Power
RBK	Rattling Brook Substation	Newfoundland Power
RFD	Roycefield Substation	Newfoundland Power
SBK	Sandy Brook Substation	Newfoundland Power
SMV	Summerville Substation	Newfoundland Power
SPO	Salt Pond Substation	Hydro & Newfoundland Power
STB/STY[3]	Stony Brook Terminal Station & Substation	Hydro & Newfoundland Power
SUM	Summerford Substation	Newfoundland Power
SSD/SUN[4]	Sunnyside Terminal Station & Substation	Hydro & Newfoundland Power
TNS	Terra Nova Substation	Newfoundland Power
TRN	Trinity Substation	Newfoundland Power
TWG	Twillingate Substation	Newfoundland Power
WBC	Webber's Cove	Newfoundland Power
WBK	West Brook Substation	Newfoundland Power
WES	Wesleyville Substation	Newfoundland Power

[3] Hydro uses "STB" for its acronym for Stony Brook, whereas Newfoundland Power uses "STY".
[4] Hydro uses "SSD" as its acronym for Sunnyside, whereas Newfoundland Power uses "SUN".

Figure A-1 depicts a section of the IIS Transmission Map that includes the Study Area.

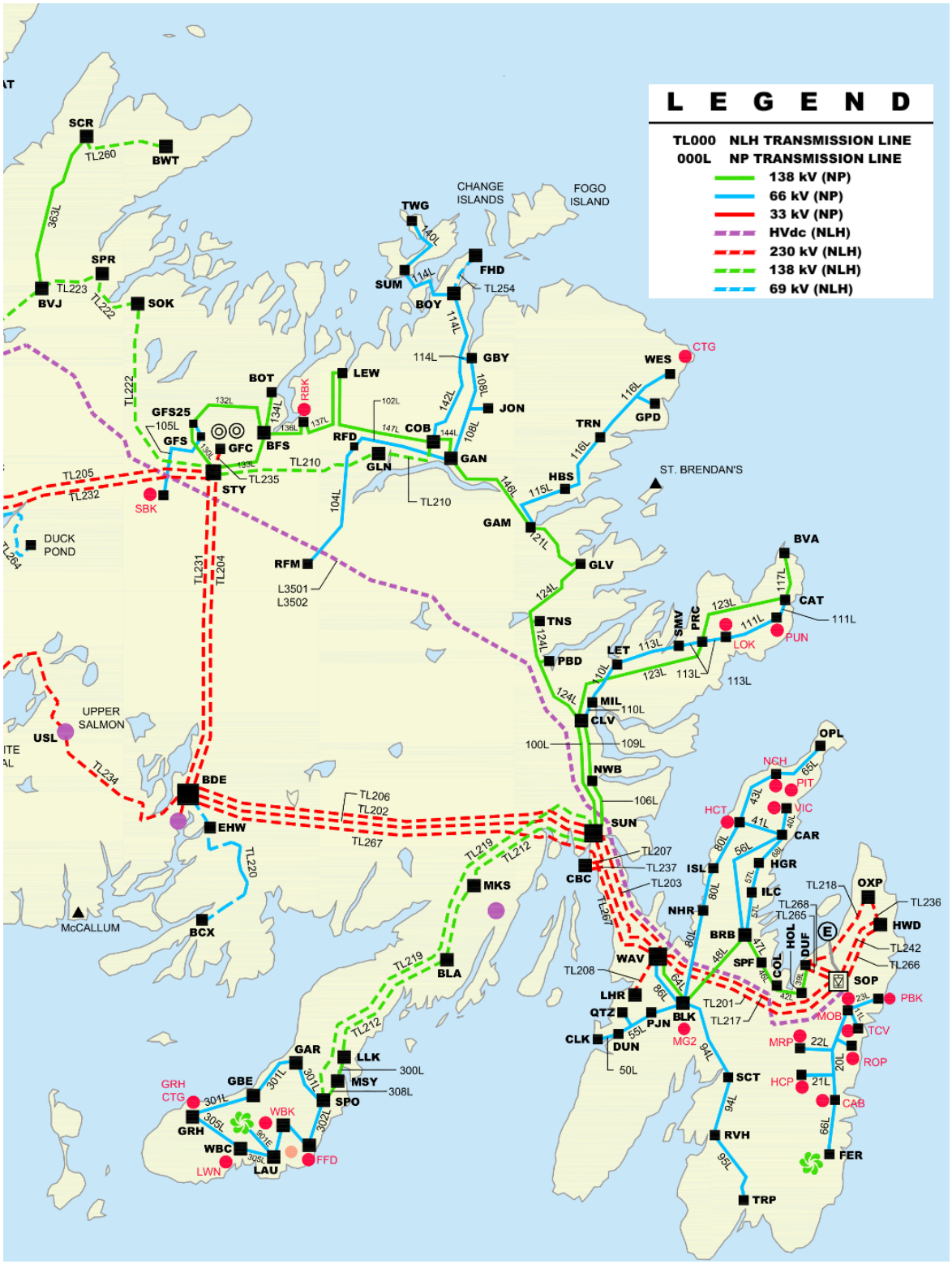


Figure A-1: Section of IIS Transmission Map that Includes the Study Area

Attachment B:

2027-2036 Loop Assessment

138kV & 66kV Loop Assessments

2027-2036

Rev. 4

Prepared by: Tony Jones, P. Eng.

May 25, 2026

Revision History

Rev. #	Comments	Date
4	Minor edits.	May 25, 2026
3	Revised based on Hydro's 2036 P90 Loads	May 20, 2026
2	-Added demand forecast table. -Revised SSD/STB section to include impact of a loss of HND-G1. -Revised tables to show de-rated transformer ratings based on tap positions. -Added results of HWD-G1 during contingencies. -Merged HWD-HRD and HWD-OPD sections.	May 4, 2026
1	Incorporated Hydro's preliminary comments.	April 13, 2026
0	Initial draft for comments.	March 23, 2026

NEWFOUNDLAND POWER
A FORTIS COMPANY

138kV & 66kV Loop Assessments: 2027-2036
Rev. 4
May 25, 2026

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Appendix A – Relevant Local Generation Assumptions for N-0 Pre-Contingency Cases

1.0 Introduction

The purpose of this report is to assess 138kV and 66kV transmission loop systems based on forecast data for 2027 – 2036. This report aims to summarize the findings of simulating various equipment outage scenarios during peak conditions and to provide recommendations to minimize customer impacts and equipment overloads for each transmission loop. The results of this report will be shared with both Newfoundland Power Inc. ("NP") and Newfoundland & Labrador Hydro ("Hydro") power system operators to inform any potential operating procedures or capital upgrades that may be required to minimize outages under the contingency scenarios herein.

2.0 Overview of Methodology

Eaton's CYME Power Engineering Software ("CYME") was used to simulate load flows under peak conditions projected for the 2027–2036 period. The area modelling was based on Hydro's 2036 P90 Forecast, which served as a scaling factor for NP's standard 2030 P90 Infeed Forecast typically applied within CYME. The corresponding 2036 P90 forecast data is provided in Table 1.

Table 1
P90 Load Forecast Data for 2036

Infeed Area	Corresponding Loops	MVA
St. John's	Holyrood - Hardwoods – Oxen Pond 66kV	901
Central + Burin[1]	Sunnyside – Stony Brook 138kV	400
Avalon	Holyrood – Western Avalon 138kV	191
Stephenville	Stephenville – Bottom Brook 66kV	60

When applicable, additional sensitivity analyses were completed for transmission loop systems with known potential large loads not yet captured in NP's Infeed Forecast to assess a high-growth scenario.

Potential equipment overloading, as well as any observed voltages outside of either NP's or Hydro's planning criteria limits based on Hydro's P90 load scenarios for each loop are presented in the following sections.[2] De-ratings of transformer capacities due to tap changer positions were also considered when appropriate. All NP hydraulic generation units in the loops were also modeled as 'on' unless otherwise stated. NP generator outputs for the pre-contingency scenarios were consistent with Hydro's own modeling assumptions which are provided in Appendix A. For post-contingency scenarios that require increased generation output up to a unit's full rating, the specified dispatched amount is provided when applicable. Load flows were analyzed for various single outages to transmission lines and system transformers to provide an assessment of potential N-1 contingency scenarios for each 138kV or 66kV loop.

[1] Includes Monkstown ("MKS") and Bay L'Argent ("BLA") infeed locations on the Burin Peninsula in addition to the Burin area.

[2] Pre-contingency voltage limits for Hydro and NP transmission lines are 0.95-1.05pu; post-contingency limits on transmission lines are 0.90-1.10pu for Hydro and 0.90-1.06pu for NP. Loading limits for transformers were based on nameplate ratings and deratings based on tap changer positions when applicable. It is understood that exceeding these ratings will not necessarily trip the transformers. Hydro is currently assessing the degree to which temporary overloads to nameplate ratings are permitted.

It should be noted that analyzing the effect of multiple outages occurring simultaneously resulting in contingency scenarios beyond N-1 is beyond the scope of this report. Curtailable loads were connected in all load flows unless otherwise specified.

3.0 Holyrood - Hardwoods – Oxen Pond 66kV Loop

The Holyrood – Hardwoods – Oxen Pond Loop ("HRD-HWD-OPD") is comprised of numerous 66kV transmission lines that supply the St. John's area from Hydro's Holyrood ("HRD"), Hardwoods ("HWD") and Oxen Pond ("OPD") terminal stations. The following sections outline load flow results for the pre-contingency scenario, as well as for various N-1 contingency scenarios due to single outages to transmission lines and system transformers within the loop. It should be noted that pre-contingency load flows were completed with the HRD diesels modeled off and the HWD combustion turbine ("HWD-G1") modeled at 25MW.[3]

3.1 Pre-Contingency

Load flow results for 2036 for the current pre-contingency system configuration are shown in Table 2.[4]

Table 2
HRD-HWD-OPD 66kV Loop
System Transformer Loading for 2036

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	P90	
				MVA	%
Holyrood	T5	25	24.7	22.5	91.1
	T10	25	24.7	21.4	86.7
Hardwoods	T1	125	122	109.1	89.4
	T2	66.6	64.9	55.7	85.8
	T3	66.6	64.9	60.3	92.9
	T4	125	122	108.3	88.8
Oxen Pond	T1	250	250	195.2	78.1
	T2	125	125	94.2	75.3
	T3	250	250	195.3	78.1

All voltages in this loop were observed to be within acceptable planning limits and as shown in Table 2, no transformer overloads were observed.

3.2 Single Line Outages (N-1)

Each 66kV transmission line within the HWD-OPD loop was individually disconnected in CYME to observe effects during peak. The results are provided in Table 3 on the following page.

[3] Hydro is currently performing a study to assess the life expectancy of the HWD combustion turbine. Depending on the conclusion of the study, the unit may be available until 2040.

[4] The results in this section include loads associated with the electrification of Memorial University of Newfoundland's ("MUN") boiler system.

Table 3 HRD-HWD-OPD 66kV Loop Effect of Transmission Line Contingency Events	
Transmission Line(s)	**Planning Criteria Violations?**
	P90
4L / 18L / 25L	No
12L / 14L	No
13L / 52L	Yes
15L / 19L /54L / 69L	No
16L / 74L	No
17L	No
18L / 72L / 73L	No
30L / 32L / 67L	Yes
31L / 70L	Yes
34L / 58L	No
33L / 35L	No
38L / 51L	No
49L / 79L	No

3.2.1 Loss of 13L / 52L

A loss of either 13L or 52L during the P90 peak resulted in marginal overloads to HWD-T3. These can be resolved by curtailing 22MW of load at MUN. See Table 4.

Table 4 HRD-HWD-OPD 66kV Loop System Transformer Loading for 2036 Loss of 13L or 52L Contingency											
Station	**Unit**	**Max Rating (MVA)**	**Unit Derating (MVA)[5]**	**13L Out**		**52L Out**		**13L Out 22MW MUN Curt.**		**52L Out 22MW MUN Curt.**	
				MVA	**%**	**MVA**	**%**	**MVA**	**%**	**MVA**	**%**
Hardwoods	T3	66.6	64.9	65.2	100.4	66.6	102.6	64.7	**99.7**	64.7	**99.7**

While curtailing 22MW of load at MUN was sufficient to marginally resolve the contingency, dispatching further NP generation in the area would result in additional load reductions to HWD-T3.[6]

[5] For the mitigation scenarios with secondary voltages at or below unity, unit deratings no longer apply. For such scenarios, the percent loading is based on the unit's maximum rating.

[6] Load flows were modeled with approximately 34MW of NP's St. John's-area generation on, out of a total of approximately 52MW available.

3.2.2 Loss of 30L

A loss of 30L during the P90 peak resulted in an overload to 14L. Up to and including 2030, disconnecting 14L results in additional power flow over adjacent lines all within winter ampacity limits and therefore resolves the loss of 30L contingency. However, commencing in 2031, this configuration results in an overload to 58L. As a result, capital upgrades may be required in 2031 to resolve the loss of 30L contingency.

3.2.3 Loss of 31L / 70L

A loss of either 31L or 70L during the P90 peak resulted in an overload to the other transmission line. Up until 2031, disconnecting 14L results in additional power flow over adjacent lines all within winter ampacity limits and therefore resolves the loss of 30L contingency. However, commencing in 2032, this configuration results in overloads to 30L and 32L. As a result, capital upgrades may be required in 2032 to resolve the loss of 31L or 70L contingencies.

3.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2036. In substations with multiple system transformers and bus voltages, the largest transformer per bus was removed. In cases where there were multiple transformers of the same size at a particular substation bus, the transformer with the smallest impedance was removed. Load flow results for the simulated outages during the 2036 case are found in Table 5.

Table 5
HRD-HWD-OPD 66kV Loop
System Transformer Loading Following XFMR Loss
2036 P90 Scenario

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	No HRD-T5		No HWD-T1		No OPD-T1	
				MVA	%	MVA	%	MVA	%
Holyrood	T5	25	24.7	*Out of service*		25.0	101.3	23.5	**95.0**
	T10	25	24.7	28.2	24.3	24.3	**98.4**	22.8	92.3
Hardwoods	T1	125	122	114.3	93.7	*Out of service*		127.9	104.8
	T2	66.6	64.9	58.4	89.9	72.5	111.8	65.3	100.6
	T3	66.6	64.9	63.2	**97.4**	78.5	120.9	70.7	108.9
	T4	125	122	113.5	93.0	140.9	115.5	126.9	104.0
Oxen Pond	T1	250	250	194.8	77.9	210.6	84.2	*Out of service*	
	T2	125	125	94.0	75.2	101.6	81.3	141.3	113.0
	T3	250	250	195.0	78.0	210.7	84.3	292.9	117.2

As shown in Table 5, transformer overloads were observed with either HRD-T5, HWD-T1 or OPD-T1 out of service. To mitigate the HRD-T5 and HWD-T1 overloads, the system was re-modeled through various combinations of operational procedures such as opening transmission line breakers; dispatching HWD-G1, HRD diesels, and NP hydraulic generation; implementing voltage reduction schemes; as well as curtailing 22MW of load at MUN. The OPD-T1 contingency, however, was unable to be mitigated.

The results of the various mitigation scenarios are presented in Table 6.

Table 6
HWD-OPD 66kV Loop:
System Transformer Loading Following XFMR Loss
2036 P90 Loading
(MITIGATION SCENARIOS)

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)[7]	(No HRD-T5) 38L Open HWD-G1 at 50MW		(No HWD-T1) 22MW MUN Curt. HWD-G1 at 50MW HRD Diesels at 8.5MW HWD 66kV at 0.99pu Max NP Generation		(No OPD-T1) 22MW MUN Curt. HWD-G1 at 50MW HRD Diesels at 8.5MW HRD 66kV at 1.00pu HWD 66kV at 0.98pu OPD 66kV at 0.96pu Max NP Generation	
				MVA	%	MVA	%	MVA	%
Holyrood	T5	25	24.7	*Out of service*		23.6	**95.6**	21.7	86.8
	T10	25	24.7	0.0	0.0	22.9	92.8	21.1	84.4
Hardwoods	T1	125	122	114.9	94.1	*Out of service*		123.1	**98.5**
	T2	66.6	64.9	58.6	90.4	60.7	91.1	62.8	94.3
	T3	66.6	64.9	63.5	**97.9**	65.6	**98.6**	68.0	102.1
	T4	125	122	114.0	93.5	117.9	94.3	122.2	**97.8**
Oxen Pond	T1	250	250	195.7	78.3	215.7	86.3	*Out of service*	
	T2	125	125	94.4	75.5	104.0	83.2	128.6	102.9
	T3	250	250	195.8	78.3	215.8	86.3	266.7	106.7

As shown in Table 6, the observed transformer overloads resulting from a loss of HRD-T5 or HWD-T1 may be mitigated through various operational procedures. The OPD-T1 contingency was unable to be successfully mitigated for the 2036 P90 case.

For the HRD contingency, opening 38L and dispatching HWD-G1 at 50MW successfully resolved the contingency.

For the HWD contingency, curtailing 22MW of load at MUN, dispatching HWD-G1 at 50MW and HRD diesels at 8.5MW, maximizing NP area generation, and reducing HWD 66kV voltage to 0.99pu successfully resolved the contingency. These mitigation strategies can successfully resolve the overload conditions until 2030.

For the OPD contingency, dispatching all area generation, lowering bus voltages, and curtailing MUN's load still resulted in overloads to HWD-T3, OPD-T2 and OPD-T3. This mitigation strategy can resolve the overload conditions until 2030. However, commencing in 2031, the overloads can no longer be mitigated. As a result, capital upgrades may be required in 2031 to resolve the loss of OPD-T1 contingency.

[7] For the mitigation scenarios with secondary voltages at or below unity, unit deratings no longer apply. For such scenarios, the percent loading is based on the unit's maximum rating.

4.0 Holyrood – Western Avalon 138kV/66kV Loop

The Holyrood – Western Avalon Loop ("HRD-WAV") is comprised of 138kV and 66kV transmission lines that run through the Avalon Peninsula between Hydro's Holyrood Terminal Station ("HRD") and the Western Avalon Terminal Station ("WAV"). The following sections outline load flow results for the pre-contingency scenario, as well as for various N-1 contingency scenarios due to single outages to transmission lines and system transformers within the loop.

4.1 Pre-Contingency

Load flow results for the 2036 P90 pre-contingency system configuration are shown in Table 7. It was found that no transformer overloads nor system voltage criteria violations were observed in the pre-contingency configuration.

Table 7
HRD-WAV 138kV/66kV Loop
System Transformer Loading for 2036

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	P90	
				MVA	%
Blaketown	T3	41.6	41.6	24.9	59.8
Bay Roberts	T2	41.6	41.6	25.8	62.1
	T3	41.6	41.6	25.4	61.0
Western Avalon	T1	25	23.8	17.0	71.3
	T2	25	23.8	17.3	72.6
	T3	41.7	40.6	14.5	35.6
	T4	41.7	40.6	14.4	35.4
	T5	125	125	42.1	33.7
Holyrood	T6	41.7	39.6	13.2	33.2
	T7	125	125	37.3	29.8
	T8	125	125	38.2	30.5

4.2 Single Line Outages (N-1)

Each 66kV and 138kV transmission line within the HRD-WAV loop were individually disconnected in CYME to observe effects during peak. The results are provided in Table 8.

Table 8
HRD-WAV 138kV/66kV Loop
Effect of Transmission Line
Contingency Events

TL	Planning Criteria Violations?
	P90
39L / 42L / 46L / 47L	No
48L	No
64L	Yes
56L / 57L / 68L	No
41L	No
80L	No
86L	No

4.2.1 Loss of 64L

A loss of 64L during the P90 peak resulted in overloads to WAV-T1 and WAV-T2. Reducing the WAV 66kV bus to 1.0pu successfully resolved the contingency. See Table 9.

Table 9
HRD-WAV 138kV/66kV Loop
System Transformer Loading for 2036

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)[8]	64L Out		64L Out WAV 66kv at 0.99pu	
				MVA	%	MVA	%
Western Avalon	T1	25	23.8	26.1	109.7	23.8	**95.2**
	T2	25	23.8	26.6	111.8	24.2	**96.8**

While reducing the WAV 66kV voltage to 0.99pu was sufficient to marginally resolve the contingency, dispatching further NP generation in the area would result in additional load reductions to WAV-T1 and WAV-T2.[9]

It should be noted that based on today's protection settings and a 2036 P90 load scenario, a loss of 64L would also result in an overload to 39L, which is currently de-rated to 560A. However, NP is currently conducting a review of the protection settings for the area and expects the de-rating condition to be

[8] For the mitigation scenarios with secondary voltages at or below unity, unit deratings no longer apply. For such scenarios, the percent loading is based on the unit's maximum rating.

[9] Load flows were modeled with 5.1MW of NP's Avalon-area generation on, out of a total of 13.2MW available.

removed later in 2026. As a result, a loss of 64L is not expected to result in an overload to 39L in future years, and 2026 loads are insufficient to result in an overload.

4.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2036. In substations with multiple system transformers and bus voltages, the largest transformer per bus was removed. In cases where there were multiple transformers of the same size at a particular substation bus, the transformer with the smallest impedance was removed. The transformers analyzed in this section are BLK-T3, BRB-T2, WAV-T2, WAV-T5, and HRD-T8. Loading results for the simulated outages during 2036 P90 peak are found in Tables 10a and 10b.

Table 10a
HRD-WAV 138kV/66kV Loop
System Transformer Loading Following XFMR Loss (HRD-T8, WAV-T2, WAV-T5)
2036 P90 Scenario

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	(No HRD-T8)		(No WAV-T5)		(No WAV-T2)	
				MVA	%	MVA	%	MVA	%
Blaketown	T3	41.6	41.6	24.6	59.1	23.3	56.0	31.3	75.2
Bay Roberts	T2	41.6	41.6	25.6	61.5	25.6	61.5	26.9	64.6
	T3	41.6	41.6	25.1	60.4	25.1	60.4	26.4	63.4
Western Avalon	T1	25	23.8	17.4	73.1	18.6	78.1	25.2	106.1
	T2	25	23.8	17.7	74.4	18.9	79.6	*Out of Service*	
	T3	41.7	40.6	15.6	38.5	30.2	74.5	15.8	38.8
	T4	41.7	40.6	15.5	38.3	30.1	74.1	15.7	38.6
	T5	125	125	45.5	36.4	*Out of service*		37.5	45.9
Holyrood	T6	41.7	39.6	21.5	54.4	14.5	36.6	13.6	34.3
	T7	125	125	61.0	48.8	41.2	32.9	38.5	30.8
	T8	125	125	*Out of service*		42.1	33.7	39.5	31.5

Table 10b HRD-WAV 138kV/66kV Loop System Transformer Loading Following XFMR Loss (BRB-T2, BLK-T3) 2036 P90 Scenario							
Station	**Unit**	**Max Rating (MVA)**	**Unit Derating (MVA)**	**(No BRB-T2)**		**(No BLK-T3)**	
				MVA	**%**	**MVA**	**%**
Blaketown	T3	41.6	41.6	29.1	70.0	*Out of service*	
Bay Roberts	T2	41.6	41.6	*Out of service*		29.2	70.1
	T3	41.6	41.6	46.6	112.1	28.6	68.8
Western Avalon	T1	25	23.8	18.4	77.3	26.7	112.1
	T2	25	23.8	18.7	78.8	27.2	114.2
	T3	41.7	40.6	14.5	35.7	11.0	27.2
	T4	41.7	40.6	14.4	35.5	11.0	27.0
	T5	125	125	42.2	33.8	32.1	25.7
Holyrood	T6	41.7	39.6	13.0	32.9	13.1	33.0
	T7	125	125	36.9	29.5	37.0	29.6
	T8	125	125	37.8	30.2	37.9	30.3

As shown in Tables 10a and 10b, transformer overloads exist with either WAV-T2, BRB-T2 or BLK-T3 out of service.

With WAV-T2 out of service, WAV-T1 is overloaded. With BLK-T3 out of service, both WAV-T1 and WAV-T2 are overloaded. Each of these contingencies can be resolved by opening 80L at BLK. With BRB-T2 out of service, BRB-T3 is overloaded. This can be mitigated by opening 48L at BRB.[10]

[10] With BRB-T2 and 48L out of service, further contingency scenarios could result in loss of supply to the entire loop system.

Load flow results for the mitigated scenarios are presented in Table 11.

Table 11
HRD-WAV 138kV/66kV Loop
MITIGATED Scenarios Following XFMR Loss

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	2036 P90 No BRB-T2 48L Open		2036 P90 No WAV-T2 80L Open		2036 P90 No BLK-T3 80L Open	
				MVA	%	MVA	%	MVA	%
Blaketown	T3	41.6	41.6	32.0	76.8	18.6	44.7	*Out of Service*	
Bay Roberts	T2	41.6	41.6	*Out of Service*		37.6	90.4	37.7	90.5
	T3	41.6	41.6	41.2	**99.1**	36.9	88.8	37.0	88.9
Western Avalon	T1	25	23.8	18.3	77.0	18.6	78.1	18.7	78.4
	T2	25	23.8	18.7	78.4	*Out of service*		19.0	79.9
	T3	41.7	40.6	10.0	24.7	16.3	40.1	12.9	31.9
	T4	41.7	40.6	10.0	24.6	16.2	39.9	12.9	31.7
	T5	125	125	29.2	23.4	47.4	37.9	37.7	30.1
Holyrood	T6	41.7	39.6	16.7	42.1	14.7	37.1	14.4	36.3
	T7	125	125	47.2	37.8	41.6	33.3	40.7	32.6
	T8	125	125	48.4	38.7	42.6	34.1	41.7	33.4

5.0 Sunnyside – Stony Brook 138kV Loop

The Sunnyside-Stony Brook loop ("SSD-STB") is comprised of numerous 138kV transmission lines that run through Central Newfoundland between Hydro's Sunnyside Terminal Station ("SSD") and Stony Brook Terminal Station ("STB"). All modeling for the SSD-STB Loop was completed with NP's new 138kV transmission line 148L in service, as well as transmission line 100L rebuilt.[11] The SSD-STB Loop also supplies the 138kV Burin Peninsula Loop system through the 138kV supply at SSD, and also impacts the 138kV transmission system west of STB, including the Deer Lake and Great Northern Peninsula systems. A transmission contingency analysis of the Burin Peninsula System is also included in this section.

[11] Transmission Line 148L is a new 138kV line between NP's Lewisporte ("LEW") and Boyd's Cove ("BOY") substations, which was filed and approved as part of *NP's 2025 Capital Budget Application*. The line is expected to be in service in 2027. Transmission Line 100L was approved to be rebuilt as part of *NP's 2026 Capital Budget Application* and is expected to be completed later in 2027.

5.1 Pre-Contingency

Load flow results for the 2036 pre-contingency configurations are shown in Table 12. The results indicate no transformer overloads or planning criteria violations.[12]

Table 12
SSD-STB 138kV Loop
System Transformer Loading for 2036

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	2036 P90	
				MVA	%
Sunnyside	T1	125	125	94.6	75.7
	T4	125	123.5	95.0	76.9
Stony Brook	T1	125	122	99.6	81.6
	T2	125	122	98.6	80.5

5.2 Single Line Outages (N-1)

The following 138kV transmission lines within the SSD-STB loop were disconnected in CYME to observe effects during peak: 100L/109L, 121L, 124L, 144L, 146L, 130L/132L/133L, 136L/137L/147L, and TL-210. The following 138kV transmission lines within the Burin Peninsula loop were also assessed: TL-212, TL-219, 300L and 308L.

[12] Presently, a transmission voltage violation affects the 66kV supply to the following substations: BOY, Summerside ("SUM"), and Twillingate ("TWG"). The construction of Transmission Line 148L in 2027 will resolve these voltage violations and they are therefore omitted from the 2036 pre-contingency results. As 148L will normally be operated as a radial supply line for BOY, SUM, TWG due to a normally open point at Gander Bay Substation ("GBY"), 148L is therefore excluded from the looped transmission line contingency analysis presented in Table 13.

The results are provided in Table 13.

Table 13
SSD-STB 138kV Loop
Effect of Transmission Line Contingency Events

Transmission Line(s)	Planning Criteria Violations?
	2036 P90
100L / 109L	No
121L	Yes
124L	Yes
130L / 132L / 133L	No
136L	Yes
137L	Yes
144L	Yes
146L	Yes
147L	Yes
TL-210	Yes
TL-212 (Burin System)	Yes
TL-219 (Burin System)	Yes
300L (Burin System)	No
308L (Burin System)	No

As shown in Table 13, multiple undervoltage conditions are linked to various transmission line contingencies. The following sections examine how the existing thermal units at WES and GRH could mitigate these issues. However, NP and Hydro are currently evaluating options to address the eventual retirement of the WES and GRH units, which are not expected to remain in service through 2036.

While the analysis considers voltage impacts with these units both in and out of service, it is important to note that, in order to provide adequate voltage support, any thermal unit would need to be dispatched during the P90 peak prior to a contingency event. NP continues to assess the cost implications associated with operating these units during these periods, in addition to their potential capabilities as synchronous condensers.

5.2.1 Loss of 121L

Transmission line 121L is a 138kV transmission line that runs between NP's Gambo Substation ("GAM") and Glovertown Substation ("GLV"). CYME analysis shows that disconnecting 121L during the 2036 P90 load scenario results in undervoltage conditions as low as 0.82pu along the 138kV network near NP's Gander ("GAN"), GAM and GLV substations, with a full voltage collapse approaching 0.40pu on NP's 66kV 115L/116L system serving Hare bay ("HBS"), Greenspond ("GPD"), Trinity ("TRN"), and Wesleyville ("WES") substations ("the 115L/116L System").

To mitigate this effect, 8MW of generation capacity at WES results in acceptable post-contingency transmission voltages of 0.95pu at the lowest levels along GAN-GAM. Alternatively, approximately 10MVAR of reactive power support at GAM could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

5.2.2 Loss of 124L

Transmission line 124L is a 138kV transmission line that runs between NP's Clarenville Substation ("CLV") and GLV. CYME analysis shows that disconnecting 124L at CLV during the 2036 P90 load scenario results in undervoltage conditions as low as 0.81pu along the 138kV network near NP's GAN, GAM and GLV substations, with a full voltage collapse approaching 0.40pu on NP's 66kV 115L/116L System.

To mitigate this effect, 8MW of generation capacity at WES results in acceptable post-contingency transmission voltages of 0.93pu at the lowest levels along GAN-GAM. Alternatively, approximately 10MVAR of reactive power support at GAM could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

5.2.3 Loss of 136L

Transmission line 136L is a 138kV transmission line that runs between NP's Bishop's Falls Substation ("BFS") and Rattling Brook Substation ("RBK"). CYME analysis shows that disconnecting 136L during the 2036 P90 load scenario results in undervoltage conditions as low as 0.86pu along the 138kV network near NP's GAN, GAM and GLV substations, with a full voltage collapse approaching 0.40pu on NP's 66kV 115L/116L System.

To mitigate this effect, 8MW of generation capacity at WES results in acceptable post-contingency transmission voltages of 0.92pu at the lowest levels near GAN-GAM. Alternatively, approximately 20MVAR of reactive power support at GAM could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

5.2.4 Loss of 137L

Transmission line 137L is a 138kV transmission line that runs between NP's RBK and LEW substations. CYME analysis shows that disconnecting 137L during the 2036 P90 load scenario results in widespread undervoltage brown-out conditions in the area.[13]

To mitigate this effect, 8MW of generation capacity at WES and 20MW of generation capacity at GRH, in conjunction with increasing STB 138kV voltage to 1.04pu results in acceptable post-contingency transmission voltages of 0.91pu at the lowest levels near LEW. Alternatively, approximately 20MVAR of reactive power support at GAM could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

[13] CYME was unable to determine load flow solutions for this contingency due to inadequate levels of available reactive power support.

5.2.5 Loss of 144L

Transmission line 144L is a 138kV transmission line that runs between NP's Cobb's Pond Substation ("COB") and GAN. CYME analysis shows that disconnecting 144L during the 2036 P90 load scenario results in severe voltage collapse as low as 0.77pu along the 138kV network near NP's GAN, GAM and GLV substations, and approaching 0.40pu on NP's 66kV 115L/116L System.

To mitigate this effect, 8MW of generation capacity at WES results in acceptable post-contingency transmission voltages of 0.94pu at the lowest levels near GAN-GAM. Alternatively, approximately 10MVAR of reactive power support at GAM could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

5.2.6 Loss of 146L

Transmission line 146L is a 138kV transmission line that runs between NP's GAN and GAM substations. CYME analysis shows that disconnecting 146L during the 2036 P90 load scenario results in undervoltage conditions as low as 0.83pu along the 138kV network near NP's GAN, GAM and GLV substations, with a full voltage collapse approaching 0.40pu on NP's 66kV 115L/116L System.

To mitigate this effect, 8MW of generation capacity at WES results in acceptable post-contingency transmission voltages of 0.97pu at the lowest levels near GAN-GAM. Alternatively, approximately 10MVAR of reactive power support at GAM could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

5.2.7 Loss of 147L

Transmission line 147L is a 138kV transmission line that runs between NP's Cobb's Pond ("COB") and LEW substations. CYME analysis shows that disconnecting 147L during the 2036 P90 load scenario results in widespread undervoltage brown-out conditions in the area.[14]

To mitigate this effect, 8MW of generation capacity at WES results in acceptable post-contingency transmission voltages of 0.96pu at the lowest levels near LEW. Alternatively, approximately 10MVAR of reactive power support at GAM could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

5.2.8 Loss of TL-210

Transmission line TL-210 is a 138kV transmission line operated by Hydro that runs between STB Terminal Station and NP's Glenwood ("GLN") and COB substations. CYME analysis shows that disconnecting TL-210 during the 2036 P90 load scenario results in widespread undervoltage brown-out conditions in the area.[15]

To mitigate this effect, 8MW of generation capacity at WES results in acceptable post-contingency transmission voltages of 0.92pu at the lowest levels near LEW. Alternatively, approximately 20MVAR of reactive power support at GAM could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

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[14] *Ibid.*
[15] *Ibid.*

5.2.9 Loss of TL-212

Hydro's 138 kV transmission line TL-212 runs between SSD, and NP's Monkstown ("MKS"), Bay L'Argent ("BLA") and Linton Lake ("LLK") substations on the Burin Peninsula. CYME analysis shows that disconnecting TL-212 during the 2036 P90 scenario results in undervoltage conditions as low as 0.86pu near SPO.

To mitigate this effect, 20MW of generation capacity at GRH results in acceptable post-contingency transmission voltages of 0.95pu at the lowest levels near SPO. Alternatively, approximately 20MVAR of reactive power support at SPO could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

5.2.10 Loss of TL-219

Hydro's 138 kV transmission line TL-219 runs between SSD and NP's SPO substation on the Burin Peninsula. CYME analysis shows that disconnecting TL-219 during the 2036 P90 scenario results in widespread undervoltage brown-out conditions in the area.[16]

To mitigate this effect, 20MW of generation capacity at GRH results in acceptable post-contingency transmission voltages of 0.93pu at the lowest levels near SPO. Alternatively, approximately 20MVAR of reactive power support at SPO could result in comparable voltages. No transformer overloads were observed during the contingency scenario.

5.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2036. In substations with multiple system transformers and bus voltages, the largest transformer per bus was removed. In cases where there were multiple transformers of the same size at a particular substation bus, the transformer with the smallest impedance was removed. The transformers analyzed in this section are SSD-T4 and STB-T2; loading results for the simulated outages for the 2036 P90 case are found in Table 14.

Table 14
SSD-STB 138kV Loop
System Transformer Loading Following XFMR Loss
2036 P90 Scenario

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	(No SSD-T4)		(No STB-T1)	
				MVA	%	MVA	%
Sunnyside	T1	125	125	197.8	158.2	98.9	79.1
	T4	125	123.5	*Out of Service*		99.3	80.4
Stony Brook	T1	125	122	111.3	91.2	*Out of Service*	
	T2	125	122	110.1	90.2	187.1	153.4

To mitigate the STB transformer overload presented in Table 14, 8MW of generation was dispatched at WES and 20MW of generation was dispatched at GRH. In addition, transmission line TL-245 was opened at Howley Terminal Station, and all local area generation was dispatched at their maximum ratings,

[16] *Ibid.*

including dispatching 5MW from MG2 stationed at COB. Furthermore, STB 138kV was set to 0.97pu, and SSD 138kV was set to 1.06pu.

To mitigate the SSD transformer overload condition, WES-GT was dispatched at 8MW and 20MW of generation was dispatched at GRH. In addition, transmission line 124L was opened at CLV to limit SSD power flow toward Central Newfoundland.

The results of the various mitigation scenarios are presented in Table 15.

Table 15
SSD-STB 138kV Loop
System Transformer Loading Following XFMR
2036 P90 Scenario (MITIGATION)

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)[17]	(No SSD-T4) 8MW at WES 20MW at GRH 124L Open at CLV		(No STB-T1) 8MW at WES, 20MWW at GRH, MG2 at 5MW at COB, TL245 Open at HOW, All area gen. at max., STB 138kV at 0.97pu SSD 138kv at 1.06pu	
				MVA	%	MVA	%
Sunnyside	T1	125	125	124.9	**99.9**	87.9	70.3
	T4	125	123.5	*Out of Service*		81.9	66.3
Stony Brook	T1	125	122	111.9	91.7	*Out of Service*	
	T2	125	122	110.8	90.8	123.5	**98.8**

As shown in Table 15, the STB/SSD Loop can support forecasted load growth through to 2036, excluding any new industrial load, provided generation capacity is maintained at WES and GRH, and all area generation, including MG2, are available. In consideration of NP's proposed WES and GRH thermal unit replacement sizes of 15MW and 30MW, respectively, these would facilitate further offloading of the SSD and STB transformers while minimizing the degree of voltage management, portable generation, and area hydraulic generation availability requirements. Otherwise, 138kV transformer upgrades at STB and/or SSD, or other transmission reconfigurations, including the installation of additional reactive power support and/or new transmission lines, would be required. NP and Hydro are currently assessing these options.

5.4 Sensitivity Analysis: New Large Loads & Thermal Generation Replacements

Hydro is currently conducting system impact studies associated with four large industrial load proponents that could potentially add up to 93MW of load within the SSD-STB Loop. Hydro's latest P90 Infeed Forecast excludes load associated from these customers. It must also be emphasized that the mitigation scenarios herein require dispatching NP's existing thermal generation at WES and GRH substations. These units are nearing the end of their service life, and it is unlikely they will be in service through 2036. NP intends to file an application for their replacement in 2026. As a result of uncertainties surrounding the

[17] For the mitigation scenarios with voltages at or below unity, unit deratings no longer apply. For such scenarios, the percent loading is based on the unit's maximum rating.

potential for 93MW of additional load, in conjunction with NP seeking approval to replace its thermal units in the near term, this section contains an additional sensitivity analysis that considers the impact of both generation replacements and new large loads.[18]

5.4.1 Pre-Contingency

In terms of transmission system planning criteria, it has been assumed that Hydro would be required to install adequate reactive power support to accommodate the 43MW load addition at BWT Terminal Station, which would avoid pre-contingency voltage violations.[19] Moreover, the existing tap settings on the STB and SSD transformers were found to be insufficient to maintain pre-contingency voltages of 0.95pu at COB substation 138kV bus. As a result, the following load flows for both the pre-contingency and post-contingency scenarios utilize a target setpoint of 1.04pu for the STB transformers unless otherwise specified.[20]

Load flow results for the pre-contingency sensitivity configuration are shown in Table 16, which shows transformer overloads in the 2036 P90 case.

Table 16
SSD-STB 138kV Loop
System Transformer Loading for 2036
93MW of Aggregate Large Loads Included

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	2036 P90	
				MVA	%
Sunnyside	T1	125	125	102.0	81.6
	T4	125	120.4	102.5	85.1
Stony Brook	T1	125	120.4	128.2	**106.5**
	T2	125	120.4	126.9	**105.4**

[18] The additional large loads modeled reflect five customers with the following capacity additions: 43MW at Bottom Waters ("BWT") Terminal Station, 25MW at GLN substation, 7MW at SSD Terminal Station, 15MW at BOT substation, and 2MW at Springdale ("SPR") substation.

[19] The addition of 43MW at BWT Terminal Station resulted in an undervoltage condition on transmission line 363L, as well at the BWT Terminal Station 138kV bus. As a result, load flow results in this section assume 25MVAR of reactive power support at BWT. It is expected that Hydro will determine actual reactive power requirements as part of its ongoing system impact study.

[20] The revised setpoint resulted in a further derating of the STB transformers, as reflected in Table 15.

To mitigate these overloads, NP's RBK and SBK generating stations can be dispatched at their full ratings. See Table 17.[21]

Table 17
SSD-STB 138kV Loop
System Transformer Loading for 2036
93MW of Aggregate Large Loads Included
NP Generation Dispatched

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	RBK and SBK at Max	
				MVA	%
Sunnyside	T1	125	125	103.3	82.6
	T4	125	120.4	103.8	86.2
Stony Brook	T1	125	122	120.7	**96.6**
	T2	125	122	119.5	**98.0**

5.4.2 Single Hydraulic Generator Outage (N-1)

Due to the potential impact of Hydro's Hinds Lake generating plant ("HLK-G1") on supply to the SSD-STB Loop, this section includes an additional contingency analysis of this plant being out of service. See Table 18.

Table 18
SSD-STB 138kV Loop
System Transformer Loading for 2036
93MW of Aggregate Large Loads Included

HLK-G1 Out of Service

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	2036 P90	
				MVA	%
Sunnyside	T1	125	125	110.7	88.6
	T4	125	120.4	111.3	92.4
Stony Brook	T1	125	120.4	143.6	119.3
	T2	125	120.4	142.1	118.0

As shown in Table 18, for the scenario in which 93MW of aggregate industrial load is added to the system by 2036, overloads to STB transformers occur when HLK-G1 is out of service. To mitigate this, load flows were re-run with 15MW of capacity modeled at WES, in conjunction with SBK and RBK outputting at their maximum rating. STB transformers were also modeled at 1.0pu to avoid unit derating. See Table 19.

[21] Increased generation from HND, RBK and SBK result in adequate voltage support along the loop for the pre-contingency scenario, so the unit derating is lower in Table 18 than it is in Table 17.

Table 19
SSD-STB 138kV Loop
System Transformer Loading for 2036
93MW of Aggregate Large Loads Included

HLK-G1 Out of Service
MITIGATION: 15MW at WES
RBK and SBK at Max
STB 138kV at 1.0pu

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	2036 P90	
				MVA	%
Sunnyside	T1	125	125	101.6	81.3
	T4	125	120.4	102.1	84.8
Stony Brook	T1	125	125	124.8	**99.8**
	T2	125	125	123.5	**98.8**

5.4.3 Single Line Outages (N-1)

Planning violations associated with single transmission line contingencies for the 2036 sensitivity configuration, along with their corresponding mitigation mechanisms, are summarized in Table 20.

Table 20[22] Effect of 138kV Transmission Line Contingency Events 2036 Winter Period Sensitivity: Includes 93MW of Potential Industrial Load			
TL Contingency	**System Impact**	**Mitigation Mechanism Applied[23]**	**Lowest Voltage Following Mitigation**
121L	GAN-GAM Area Voltage Collapse	15MW at WES or 10MVAR at GAM	>0.95pu
124L	GAN-GLV Area Voltage Collapse	15MW at WES or 20MVAR at GAM	>0.93pu
144L	GAN-GLV Area Voltage Collapse	15MW at WES or 10MVAR at GAM	>0.97pu
137L	LEW-GAN Voltage Collapse	15MW at WES and MG2 at COB or 35MVAR at GLN	>0.90pu[24]
TL-210	LEW-GAN Voltage Collapse	15MW at WES or 40MVAR at GLN	>0.90pu[25]
147L	115L/116L Voltage Collapse[26]	15MW at WES or 5MVAR at GAM	>0.99pu
TL-212	Burin Peninsula Voltage Collapse	15MW at GRH or 20MVAR at SPO	>0.97pu
TL-219	Burin Peninsula Voltage Collapse	15MW at GRH or 20MVAR at SPO	>0.93pu

The results in Table 20 illustrate several 'voltage collapse' scenarios where CYME was unable to calculate a solution. These reflect brown-out scenarios associated with inadequate reactive power to maintain system voltages. It is assumed that for such load flows, voltages would be less than 0.80pu. NP's planned generation replacements, in conjunction with having MG2 available in Central Newfoundland, mitigate all transmission line contingency violations under the large load sensitivity, assuming they were dispatched during the P90 peak prior to any contingency event.[27] Alternatively, up to 80MVAR of additional reactive power support for the combined Central and Burin systems may be required, excluding the 25MVAR that may be required to support the potential customer at BWS. The exact reactive power requirements are currently being assessed by Hydro as part of a customer interconnection study.

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22 Despite larger loading for the sensitivity scenario, all load flows in Section 5.4 assume 25MVAR of reactive power support at Bottom Waters Terminal Station ("BWS"). As a result of this additional reactive power support, there are fewer transmission line planning violations in Table 20 than there are in Section 5.2.

23 Reactive power support applied as mitigation mechanisms have been approximated in increments of 5MVAR.

24 NP is currently undertaking a capacitor bank study that aims to improve power factor in the area of Twillingate and Summerford, which is expected to improve the transmission voltages observed under a 137L contingency. Similarly, Hydro is currently assessing capacitor banks at GLN to support the potential 25MW load addition, which is also expected to improve voltages in the area. Dispatching MG2 at COB was also found to improve voltages in the area following either a 137L or TL-210 contingency.

25 *Ibid.*

26 During a loss of 147L, voltages along the SSD-STB Loop remain above 0.90pu; however, a voltage collapse would still occur on the 66kV radial network consisting of transmission lines 115L and 116L.

27 NP is currently assessing 15MW combustion turbines to replace existing facilities at WES and GRH substations. One unit at WES substation could support peak demand on the 115L/116L transmission network, and two units at GRH could support peak demand on the 301L/302L/305L network. The new replacement generation units would also mitigate all transmission line and transformer contingency violations observed in Sections 5.2 and 5.3.

5.4.4 Single Transformer Outages (N-1)

Planning violations associated with single transformer contingencies for the 2036 sensitivity configuration are provided in Table 21. Substantial overloads were observed.

Table 21
Effect of 138kV Transformer Line Contingency Events
2036 Winter Period
Sensitivity: Includes 93MW of Potential Industrial Load

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)[28]	(No SSD-T4)		(No STB-T1)	
				MVA	%	MVA	%
Sunnyside	T1	125	125	202.3	161.8	108.6	86.9
	T4	125	120.4	*Out of Service*		109.1	90.6
Stony Brook	T1	125	120.4	136.1	113.0	*Out of Service*	
	T2	125	120.4	134.7	111.9	254.0	211.0

To mitigate the overload conditions, in addition to dispatching NP's proposed thermal units in conjunction with voltage management strategies, a third transformer at STB was considered. The results are provided in Table 22.

Table 22
Effect of 138kV Transformer Line Contingency Events
2036 Winter Period
Sensitivity: Includes 93MW of Potential Industrial Load

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)[29]	(No SSD-T4) 15MW at WES 30MW at GRH 124L Open STB-T3 Added		(No STB-T1) 15MW at WES STB 138kV at 1.0pu STB-T3 Added	
				MVA	%	MVA	%
Sunnyside	T1	125	125	124.0	**99.2**	101.2	81.0
	T4	125	120.4	*Out of Service*		101.7	84.5
Stony Brook	T1	125	120.4 or 125[30]	100.0	83.1	*Out of Service*	
	T2	125	120.4 or 125[31]	99.0	82.2	121.8	**97.4**
	T3-New	125	120.4 or 125[32]	99.0	82.2	121.8	**97.4**

As shown in Table 22, NP's proposed thermal replacement plants at WES and GRH substations, in addition to a third 125MVA transformer at STB, facilitate the mitigation of the STB and SSD transformer contingencies.

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28 For the mitigation scenarios with voltages at or below unity, unit deratings no longer apply. For such scenarios, the percent loading is based on the unit's maximum rating.

29 *Ibid.*

30 Unit deratings are 120.4 for the SSD contingency and 125 for the STB contingency based on specified voltage setpoints.

31 *Ibid.*

32 *Ibid.*

In summary, the STB/SSD loop, in its current configuration, is unable to support the additional potential for 93 MW. It was also determined that if any one of the potential large load customers were to be interconnected, system upgrades would be required. Therefore, accommodating any single increase would require either replacing WES/GRH and increasing transformer capacity at STB, or increasing transformer capacity at both STB and SSD, in conjunction with additional reactive power support and other transmission reconfigurations which may include new 138kV lines.

Additional analysis completed by NP to date indicates that replacing firm capacity at WES and GRH, in conjunction with adding transformer capacity at STB, could represent a least-cost component of a broader solution to address identified system needs. While this Loop Assessment is limited to evaluating contingency violations, the proposed upgrades are consistent with broader reliability and capacity requirements and align with longer-term system planning considerations. NP and Hydro will continue joint planning efforts to further inform a more holistic approach to serving forecasted demand and any additional industrial load that may materialize in the near term.

6.0 Stephenville – Bottom Brook 66kV Loop

The Stephenville – Bottom Brook Loop ("SVL-BBK") is comprised of numerous 66kV transmission lines that run through Western Newfoundland between Hydro's Stephenville Terminal Station ("SVL") and the Bottom Brook Terminal Station ("BBK"). The following sections outline load flow results for a pre-contingency scenario, as well as for various N-1 contingency scenarios due to single outages to transmission lines and system transformers along the loop. It should be noted that the previously approved project to replace BBK-T2 with a 230/66kV 66.6MVA transformer as proposed in Hydro's 2021 Capital Budget Application has been canceled, and Hydro is currently conducting a condition assessment on the 50MW SVL combustion gas turbine ("SVL-GT") and is considering extending its service life to 2035.

6.1 Pre-Contingency

Load flow results for P90 2036 for the current pre-contingency system configuration are shown in Table 23. It should be noted that pre-contingency load flows were completed with the SVL combustion turbine ("SVL-G1") modeled at 25MW.[33,34] No overloads were observed.

Table 23
SVL-BBK 66kV Loop
System Transformer Loading for 2036

Station	Unit	Max Rating (MVA)	Unit Derating (MVA)	P90	
				MVA	%
Stephenville	T3	66.6	64.9	32.6	50.2
Bottom Brook	T2	25	25	0.4	1.6

[33] Hydro is currently performing a study to assess the life expectancy of the SVL combustion turbine. Depending on the conclusion of the study, the unit may be available until 2040.

[34] A normally-open ("N/O") point exists between transmission lines 400L and 404L at NP's Wheeler's Substation ("WHE"). As a result, under normal conditions, loading on BBK-T2 is limited to line charging current on Transmission Line 400L. The N/O point can be closed under certain conditions to provide an emergency backup supply to the SVL area from BBK.

6.2 Single Line Outages (N-1)

Each 66kV transmission line within the SVL-BBK loop was individually opened in CYME to observe effects during peak. The results are provided in Table 24.

Table 24
SVL-BBK 66kV Loop
Effect of Transmission Line
Contingency Events

Transmission Line	Planning Criteria Violations?
	P90
400L / 404L	No
401L / 405L / 406L	No
TL-209	Yes

It was found that the loss of any one 66kV transmission line within the SVL-BBK loop resulted in no transformer overloads or voltage criteria violations. However, a loss of 230kV transmission line TL-209 resulted in a loss of supply to SVL-T3, which is discussed in the following section.

6.3 Single Transformer Outages (N-1)

In addition to assessing various transmission line outages, the effect of single system transformer outages within the loop were also analyzed for 2036. The transformers analyzed in this section are SVL-T3 and BBK-T2; loading results for the simulated outages for the P90 case are found in Table 25.

Table 25
SVL-BBK 66kV Loop
System Transformer Loading Following XFMR Loss

Station	Unit	Max Rating (MVA)	2036 P90 (No SVL-T3) SVL-GT at 35MW N/O Pt. Closed	
			MVA	%
Stephenville	T3	66.6	*Out of service*	
Bottom Brook	T2	25	23.8	**95.2**

Under normal conditions, a loss of SVL-T3 without SVL-G1 available results in a loss of load to the entire SVL area. However, the N/O point between 400L and 404L can be closed to provide a limited degree of backup to the area, when required.[35] As shown in Table 25, with the N/O point closed, a loss of SVL-T3 during the 2036 P90 can be mitigated if SVL-GT is dispatched at a minimum of approximately 35MW.

It should also be noted that both NP and Hydro are aware of an additional large load proponent with future plans to connect to the 66 kV network at NP's St. George's ("STG") substation. This would result

[35] Presently, protection coordination schemes are based on this N/O point being open. As a result, further analysis would be required to implement a contingency protection scheme to avoid mis-coordination events if the N/O point were to be closed.

in up to 15MW of additional load by 2035. As a result, further upgrades to SVL-BBK Loop may be required to accommodate this additional load, depending on the long-term plan for SVL-G1.

7.0 Summary

A summary of CYME load flow results for each loop outlined in this report are as follows:

- HRD-HWD-OPD 66kV Loop
    - No overloads or planning criteria violations were observed during the pre-contingency 2036 P90 load scenario.
    - Disconnecting 30L during the 2036 P90 scenario resulted in an overload to 14L. Up to and including 2030, disconnecting 14L results in additional power flow over adjacent lines to all be within winter ampacity ratings. However, commencing in 2031, this would result in an overload to 58L. As a result, capital upgrades may be required by 2031 to resolve the loss of 30L contingency.
    - Disconnecting 31L or 70L during the 2036 P90 scenario resulted in an overload to the other transmission line. Up until 2031, disconnecting 14L results in additional power flow over adjacent lines to all be within winter ampacity ratings, for either contingency. However, commencing in 2032, this would result in overloads to 30L and 32L. As a result, capital upgrades may be required by 2032 to resolve the loss of 31L or 70L contingencies.
    - Disconnecting 52L during the 2036 P90 scenario resulted in an overload to HWD-T3. This could be mitigated by a 22MW load curtailment at MUN.
    - A loss of either HRD-T5, HWD-T1 or OPD-T1 during the 2036 P90 load scenario resulted in various transformer overloads in HRD, HWD and OPD at normal operating voltages. The HRD and HWD overloads could be mitigated in CYME by implementing some combination of: a voltage management scheme at OPD, HWD and HRD; a 22MW load curtailment at MUN; dispatching all local NP generation; dispatching the HRD diesel units; and/or dispatching HWD-G1 if it is still in-service by 2035. The OPD contingency can be mitigated by similar methods until 2030. However, commencing in 2031, the overload condition was unable to be mitigated. As a result, capital upgrades may be required by 2031 to resolve the OPD-T1 contingency.
    - Hydro and NP will continue coordinated planning efforts to assess holistic, least-cost transmission supply options for the St. John's area, including both 230kV and 66kV contingencies.
- HRD-WAV 66/138kV Loop
    - No overloads or planning criteria violations were observed during the pre-contingency 2036 P90 load scenario.
    - Disconnecting 64L during the 2036 P90 scenario resulted in overloads to WAV-T1 and WAV-T2. This can be mitigated in CYME by reducing WAV 66kV voltage to 1.0pu.

- An overload to BRB-T3 was observed following the loss of BRB-T2 during the 2036 P90 scenario. This overload was mitigated in CYME by opening 48L in BRB.

- A loss of either WAV-T1 or BLK-T3 during the 2036 P90 load scenario resulted in transformer overloads at WAV. These overloads were mitigated in CYME by opening 80L at BLK.

- SSD-STB 138kV Loop

  - No overloads or planning criteria violations were observed during the pre-contingency 2036 P90 load scenario.[36]

  - Various undervoltage conditions to transmission lines in the Central Newfoundland area were observed when 121L, 124L, 136L, 137L, 144L, 146L, 147L or TL-210 were disconnected during the 2036 P90 scenario. All observed undervoltages were able to be mitigated in CYME by dispatching either 8MW of generation at WES or installing up to 20MVAR of reactive power support at GAM.

  - Various undervoltage conditions to transmission lines in the Burin Peninsula area were observed when either TL-212 or TL-219 were disconnected during the 2036 P90 scenario. All observed undervoltages were able to be mitigated in CYME by dispatching either 20MW of generation at GRH or installing up to 20MVAR of reactive power support at SPO.

  - An overload to SSD-T1 was observed following a loss of SSD-T4 during the 2036 P90 scenario. The overload was able to be mitigated in CYME by dispatching 8MW of generation at WES along with 20MW of generation at GRH. In addition, 124L was opened at CLV to limit power flow from SSD toward Central Newfoundland, thereby further offloading SSD-T1.

  - An overload to STB-T1 was observed following a loss of STB-T2 during the 2036 P90 scenario. The overload was able to be mitigated by dispatching 8MW of generation at WES and 20MW of generation at GRH. In addition, TL-245 was opened at HOW, all local hydraulic generation was dispatched at their full ratings, and MG2 was dispatched at COB.

  - Under the status quo scenario, and without consideration of the proposed new industrial load, the SSD-STB Loop can support forecast load growth to 2036, provided WES and GRH can supply at least 8 MW and 20 MW, respectively, and MG2 is available at COB.

  - Further load flows were conducted assuming up to 93MW of large industrial load additions. NP's proposed replacement units at WES (15MW) and GRH (30MW) along with a third 125MVA transformer at STB were found to resolve all planning violations. Moreover, transformer upgrades at STB may be required if either one of the large load customers were to materialize.

[36] This assumes the construction of a new 138kV transmission line 148L between LEW and BOY in 2027 to mitigate existing 66kV voltage violations at BOY, SUM, and TWG.

- Hydro and NP will continue to work together evaluate the STB/SSD Loop system across a range of load and generation scenarios. The study will identify the least cost solution to accommodate the various scenarios. Additional analysis completed by NP to date indicates that replacing firm capacity at WES and GRH represents a least-cost component of a broader solution to address identified system needs, including providing system capacity as well as addressing local reliability requirements.

- STV-BBK 66kV Loop

  - No overloads or planning criteria violations were observed during the pre-contingency analysis of the 2036 P90 load scenario.

  - An overload to BBK-T2 was observed following the loss of either SVL-T3 or TL-209. This could be mitigated by dispatching SVL-GT at 35MW, which would also require closing a N/O point between transmission lines 400L and 404L. Hydro is currently performing a condition assessment of this unit to determine if its service life can be extended to 2035. Further analysis would also be required to implement a contingency protection scheme to avoid mis-coordination events if the N/O point were to be closed.

  - It should also be noted that both NP and Hydro are aware of an additional large load proponent with future plans to connect to the 66 kV network at NP's STG substation. As a result, further upgrades to the SVL-BBL Loop may be required to accommodate this additional load.

Appendix A – Relevant Local Generation Assumptions for N-0 Pre-Contingency Cases

Loop System Generator Loading for 2036 [MW]				
Generator	**Loop**	**Owner**	**Modeled Power for N-0 Cases**	**Full Capacity Rating**
St. Lawrence	SSD-STB	Elemental Energy	6.0	27.0[37]
Fermeuse	HRD-HWD-OPD	Elemental Energy	6.0	27.0[38]
Paradise River	SSD-STB	Hydro	8.0	8.0
Hind's Lake	SSD-STB	Hydro	67.0	75.0
Heart's Content	HRD-WAV	NP	1.7	2.7
New Chelsea	HRD-WAV	NP	2.7	4.3
Pittman's Pond	HRD-WAV	NP	0.4	0.6
Victoria	HRD-WAV	NP	0.3	0.6
MG2	SSD-STB	NP	0.0	5.5
Fall Pond	SSD-STB	NP	0.1	0.3
Greenhill	SSD-STB	NP	0.0	20.0
Lawn	SSD-STB	NP	0.3	0.6
West Brook	SSD-STB	NP	0.2	0.7
Lockston	SSD-STB	NP	1.6	3.0
Port Union	SSD-STB	NP	0.3	0.6
Rattling Brook	SSD-STB	NP	7.8	14.8
Sandy Brook	SSD-STB	NP	3.3	6.3
Wesleyville	SSD-STB	NP	0.0	8.0
Cape Broyle	HRD-HWD-OPD	NP	4.4	6.3
Horsechops	HRD-HWD-OPD	NP	5.9	8.1
Mobile	HRD-HWD-OPD	NP	6.6	10.5
Morris	HRD-HWD-OPD	NP	0.8	1.1
Petty Harbour	HRD-HWD-OPD	NP	3.4	5.4
Pierre's Brook	HRD-HWD-OPD	NP	3.1	4.1
Rocky Pond	HRD-HWD-OPD	NP	2.3	3.3
Seal Cove	HRD-HWD-OPD	NP	1.9	3.6
Topsail	HRD-HWD-OPD	NP	1.4	2.6
Tors Cove	HRD-HWD-OPD	NP	3.8	6.6
Lookout Brook	SVL-BBK	NP	2.8	5.8

[37] Although the windfarms in St. Lawrence and Fermeuse have maximum ratings of 27MW, these are not considered to be firm, dispatchable sources of supply. As a result, load flow results in this report assume 6MW output from these units for both pre- and post-contingency cases.

[38] *Ibid.*

Attachment C:

Hydro Technical Note TP-TN-307

TP-TN-307

Sunnyside/Stony Brook 138 kV Loop Analysis

1 Purpose

The purpose of this technical note is to investigate technical solutions for the Sunnyside/Stony Brook 138 kV loop in high load growth scenarios where Newfoundland Power's Wesleyville and Greenhill gas turbines are not in service. This analysis provides additional perspective in support of the Newfoundland Power 138 kV & 66 kV Loop Assessments, [1] which included a review of base case load forecast scenarios where the gas turbines were available for capacity support, as well as sensitivity analysis for new large loads and thermal generation replacement.[2] The Sunnyside/Stony Brook 138 kV loop analysis presented in this technical note provides a high-level assessment and screening of potential transmission solutions assuming the retirement of Newfoundland Power's Wesleyville and Greenhill gas turbines.

2 Introduction

The Sunnyside/Stony Brook loop is comprised of numerous 138 kV transmission lines that run through Central Newfoundland between Newfoundland and Labrador Hydro's ("Hydro's") Sunnyside Terminal Station ("SSD") and Stony Brook Terminal Station ("STB"). It also supplies the 138 kV Burin Peninsula Loop system through the 138 kV supply at SSD, and the 138 kV Deer Lake/Stony Brook Loop system through the 138 kV supply at STB. Newfoundland Power owns and operates two gas turbines that are located within the loop (one at Wesleyville ("WES GT"), and one at Greenhill ("GRH GT"), that are both nearing end of life.

The Sunnyside/Stony Brook loop could experience significant load growth in the next 10 years. This potential load growth, combined with Newfoundland Power's two gas turbines approaching end of life,[3] drives the need to study the loop to assess the system impacts without these gas turbines.[4] As such, Hydro's analysis did not include capacity supplied by WES GT or GRH GT.

Figure 1 shows the locations of the three regions that are connected to the Sunnyside/Stony Brook loop.

[1] 138 kV & 66 kV Loop Assessments 2027-2036 Rev. 4, dated May 25, 2026.

[2] New large loads of up to 93 MW of new industrial customers in the SSD/STB 138 kV loop, and the following thermal generation replacements: WES GT (15 MW) and GRH GT (30 MW).

[3] Newfoundland Power indicated in their Loop Assessment report that "These units are nearing the end of their service life, and it is unlikely they will be in service through 2036."

[4] WES GT is a 16 MW combustion turbine originally commissioned in 1969 and is currently de-rated to 8 MW. While the unit remains operational, it is nearing the end of its service life. GRH GT is a 25 MW combustion turbine originally commissioned in 1975 and is currently derated to 20 MW. While the unit remains operational, it is nearing the end of its service life.

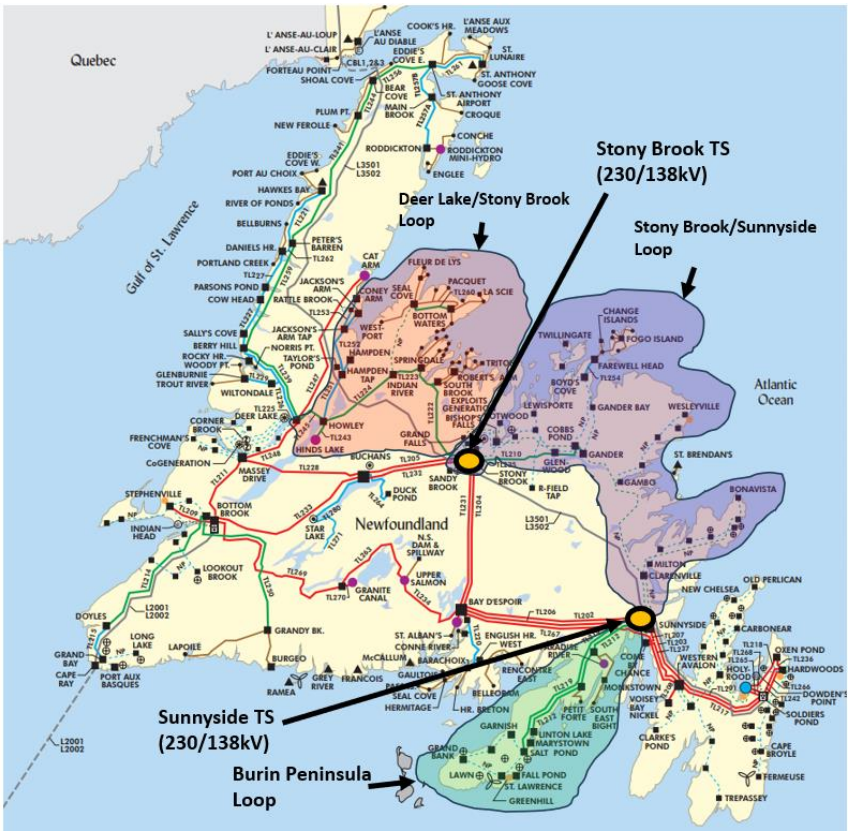


Figure 1: Locations of the three regions

3 Load Forecast utilized in Analysis

The load flow cases for the winter of 2035/2036 (P90) and the summer of 2035 (P50) were developed in accordance with the most recent Load Forecast for the Island Interconnected System.[5] The Transmission Planning analysis was assessed using the high growth forecast with all the potential industrial customer load added to the SSD/STB loop. There is uncertainty as to whether these loads will materialize. However, it is important to understand the system upgrades that would be required under such a scenario to ensure the robustness of proposed solutions.

[5] As per *Island Interconnected System Peak Demand Forecast - Spring 2025*, prepared by Market Analysis & Load Forecasting Section, Resource and Transmission Planning.

4 Analysis

Steady state load flow analysis was performed to assess the following three technical solutions within the STB/SSD loop:

1) Installation of parallel 138 kV transmission lines;
2) Installation of 138 kV capacitors banks; and
3) Installation of a combination of 138 kV capacitor banks and parallel 138 kV transmission lines.

The load flow study was completed using Version 33 of PSS®E.

4.1 Study Assumptions

The following assumptions were applied to this analysis:

- A third 138/230 kV, 125 MVA transformer is in service at both STB and SSD;
- Newfoundland Power's new 138 kV transmission line 148L between Lewisporte ("LEW") and Boyd's Cove ("BOY") Substations is in service;
- Newfoundland Power's 138 kV transmission line 100L between Clarenville ("CLV") and Sunnyside Substations has been upgraded and rebuilt;
- A tap has been added to Newfoundland Power's 138 kV transmission line 147L, to connect to the Glenwood ("GLN") Substation (assumed to be 1 km in length, with 559.5 kcmil Darien AAAC conductor);
- The following potential industrial customer loads are in service:
    - Customer 1:
        - 5 MW, 0.9 PF, connected to 25 kV bus at Botwood ("BOT") Substation;
        - 10 MW, 0.9 PF, connected to STB via a 230 kV transmission line (assumed to be 37.5 km in length, with 795 kcmil Drake ACSR conductor);
    - Customer 2: 25 MW, 0.9 PF, connected to 138 kV bus at GLN;
    - Customer 3: 7 MW, 0.95 PF, connected to 138 kV bus at SSD;
    - Customer 4:
        - 35 MW, 0.97 PF;
        - Point of Interconnection ("POI") - connected via a tap on 138 kV transmission line TL260 (tap located 23.04 km from Bottom Waters Terminal Station ("BWT"));
        - Capacitor bank - 25 MVAR at POI.
- There is assumed increased load growth at BWT – Peak load case set to 20.7 MW less 5.6 MW of Customer 4 load, for a total of 15.1 MW, 0.983 PF;
- The following Newfoundland Power generating units are out of service:
    - WES GT
    - GRH GT
    - MG2 Mobile GT
- All additional parallel 138 kV lines modelled were assumed to be 559.5 kcmil Darien AAAC conductor.

4.2 Analysis Criteria

The following steady state analysis criteria[6] were applied in completing this study:

- For normal operations, all voltages shall be maintained between 95% and 105%.
- For contingency or emergency situations, all voltages shall be maintained between 90% and 110%.

Note: This analysis did not include any dynamic analysis.

4.3 Operating Scenarios

The following operating scenarios were examined as part of the load flow analysis for each of the three alternatives under consideration:

1) 2035/2036 P90 peak load case and 2035 light load case:
    a. N-0 normal system operation; and
    b. N-1 contingency operation with 138 kV transmission lines out-of-service.

Table 1 shows the list of 138 kV transmission lines that were taken out of service, along with associated location.

Table 1: 138 kV Transmission Line Contingencies (N-1)

Impacted Loop	138 kV Line Contingencies
Sunnyside/Stony Brook	109L, 100L, 124L, 121L, 146L, 144L, TL210 (GLN to Cobb's Pond ("COB")), TL210 (STB to GLN), 147L, 148L, 133L, 132L, 130L, 137L, 136L
Burin Peninsula	TL219, TL212
Deer Lake/Stony Brook	TL224, TL223, TL222

4.4 Pre-Contingency Load Flow Analysis (N-0)

Steady-state analysis was performed to assess the SSD/STB loop under pre-contingency (N-0) conditions for both peak and light load cases.

For the peak load case, the analysis indicated voltage violations in the Sunnyside/Stony Brook loop, especially in the Gander ("GAN"), Gambo ("GAM") and Glovertown ("GLV") areas. Additionally, there were voltage violations observed at BWT (25 kV).

For the light load case, all bus voltages remained within planning criteria limits (0.95 – 1.05 pu), and no voltage violations were observed.

4.5 Contingency Load Flow Analysis (N-1)

For peak load conditions, the voltage violations identified under pre-contingency became more severe under N-1 contingencies across the SSD/STB loop, as well as in the Burin Peninsula and DLK/STB loop.

The performance of the system was assessed for three different solutions: addition of transmission lines, addition of capacitor banks, and a combination of both, to determine effective mitigation measures.

[6] As per *NLSO Standard TP-S-007 "Transmission Planning Criteria"*.

In the N-1 contingency light load case, there were two transmission line violations identified when 138 kV transmission line TL222 from STB to Springdale is out of service:

- 138 kV transmission line TL224 from Howley ("HLY") to Indian River ("IRV") becomes overloaded to 102% - resolved by the addition of a parallel line (assumed to be 57.5 km in length and 559.5 kcmil Darien AAAC conductor).
- 66 kV transmission line TL225 from Deer Lake ("DLK") to Deer Lake Power ("DLP") becomes overloaded to 122% - resolved by the addition of a parallel line (assumed to be 1.6 km in length and 559.5 kcmil Darien AAAC conductor).

4.5.1 Load Flow Analysis - Addition of 138 kV Transmission Lines

This alternative included adding parallel 138 kV transmission lines into the SSD/STB loop to address the voltage violations observed under both pre-contingency and N-1 contingency scenarios.[7] Several options were considered, however, only parallelling TL210 from Stony Brook to Glenwood and Glenwood to Gander resolved all the violations. Additionally, options were explored for the Burin Peninsula and DLK/STB loop systems. Table 2 provides a summary of the Transmission Line[8] options that were assessed.

Table 2: 138 kV Transmission Line Addition Options

Options	Distance (km)	Resolve all Violations (Y/N)
Add 138 kV line from STB to GLN (parallel to TL210)	61.4	N
Add 138 kV from GLN to GAN (parallel to TL210)	23.3	N
Add 138 kV from STB to GLN and GLN to GAN (parallel to TL210)	84.5	Y (for SSD/STB loop)
Add 138 kV from GAN to GAM (parallel to 146L)	40.7	N
Add 138 kV from COB to GAN (parallel to 144L)	6.0	N
Add 138 kV line from SSD to Monkstown ("MKS") (parallel to TL212)	57.7	N
Tap TL219 into substations on Burin Peninsula	Less than 1	Y (for Burin Pen.)
Add 138 kV line from HLY to IRV (parallel to TL224)	57.5	Y (for DLK/STB loop)

The 138 kV transmission line contingencies and recommendations for each contingency are shown in Tables 3 to 5.

Table 3: SSD/STB Loop - 138 kV Transmission Line N-1 Contingency Results

Contingency (N-1)	Results/Voltage impacts	Mitigation/Recommendation
124L	Model does not converge	Install a 138 kV line parallel to TL210 from STB to GLN and from GLN to GAN
144L	Widespread low voltages around loop (Undervoltage <0.90 pu)	Install a 138 kV line parallel to TL210 from STB to GLN and from GLN to GAN

[7] Each option considered included a 1 km long tap connecting Newfoundland Power's 138 kV transmission line 147L to the Glenwood Substation.

[8] A 559.5 kcmil Darien AAAC conductor was assumed for all parallel lines.

Contingency (N-1)	Results/Voltage impacts	Mitigation/Recommendation
137L	Widespread low voltages around loop and TL210 becomes overloaded (102%) (Undervoltage <0.90 pu)	Install a 138 kV line parallel to TL210 from STB to GLN
136L	Low voltages at COB, GAN, Twillingate ("TWG") (Undervoltage <0.90 pu)	Install a 138 kV line parallel to TL210 from STB to GLN
133L	No violations	N/A
132L	No violations	N/A
121L	Widespread low voltages around loop (Undervoltage <0.90 pu)	Install a 138 kV line parallel to TL210 from STB to GLN
147L	No violations	N/A
146L	No violations	N/A
148L	Low voltages on TWG NP (Undervoltage <0.90 pu)	Install a 138 kV line parallel to TL210 from STB to GLN and from GLN to GAN
130L	No violations	N/A
109L	No violations	N/A
100L	No violations	N/A
TL210 (STB to GLN)	Widespread low voltages around loop (Undervoltage <0.90 pu)	Install a 138 kV line parallel to TL210 from STB to GLN
TL210 (GLN to COB)	No violations	N/A

Table 4: Burin Peninsula Loop – 138 kV Transmission Line N-1 Contingency Results

Contingency (N-1)	Results/Voltage impacts	Mitigation/Recommendation
TL219 (From SSD to Salt Pond ("SPO"))	Low voltage at BLA, LLK, MSY and SPO (Undervoltage <0.90 pu)	Tap TL219 to MKS and BLA
TL212 (SSD to MKS)	No violations	N/A
TL212 (MKS to Bay L'Argent ("BLA"))	Low voltage at BLA, SPO (Undervoltage <0.90 pu)	Tap TL219 to MKS
TL212 (BLA to Linton Lake ("LLK")	No violations	N/A

Table 5: DLK/STB Loop – 138 kV Transmission Line N-1 Contingency Results

Contingency (N-1)	Results/Voltage impacts	Mitigation/Recommendation
TL245	No violations	N/A
TL224	Model does not convege	Install a 138 kV line parallel to TL224 from HLY to IRV[9][10]
TL223	No violations	N/A
TL222	Low voltages on BWT B1 (Undervoltage <0.90 pu)	Increase shunt capacitor bank at FireFly POI from 25 MVAR to 27 MVAR, as per SIS

The recommended transmission line additions required to mitigate the N-1 contingency violations are summarized as follows:

- **SSD/STB Loop:** For the SSD/STB Loop the recommended option to resolve all voltage violations is to install a 138 kV line parallel to TL210 from STB to GLN (61.4 km) and from GLN to GAN (23.3 km).
- **Burin Peninsula:** For the Burin Peninsula loop the recommended option to resolve all the voltage violations is to tap TL219 (minimal conductor length) into the Monkstown and Bay L'Argent substations.
- **DLK/STB Loop:** For the DLK/STB loop the recommended option to resolve all the voltage violations is to install a 138 kV line parallel to TL224 from HLY to IRV (57.5 km) or a Remedial Action Scheme which will be studied further.

4.5.2 Load Flow Analysis - Addition of 138 kV Capacitor Banks

This alternative considered the addition of shunt capacitor banks at selected 138 kV buses within the SSD/STB loop to address undervoltage conditions observed under both pre-contingency and N-1 contingency scenarios.[11]

Initial capacitor bank placements were evaluated to ensure all bus voltages were maintained within acceptable pre-contingency limits (0.95 to 1.05 pu). Additional reactive support was then incrementally applied to mitigate violations under transmission line outage scenarios.

Table 6 shows the capacitor bank additions required to achieve acceptable pre-contingency voltage levels.

[9] One of the recommendations for the connection of Customer 4 to the Bottom Waters system is to construct a second 138 kV transmission line, spanning 57.5 km, between Howley Terminal Station and Indian River Terminal Station.

[10] A Remedial Action Scheme is being considered as part of the Customer 4 System Impact Study.

[11] Each option considered included a 1 km long tap connecting Newfoundland Power's 138 kV transmission line 147L to the Glenwood Substation.

Table 6: N-0 Pre-Contingency Capacitor Bank Additions

Bus	Capacitor Size (MVAR)
Glenwood 138 kV	15
Gander 138 kV	10
Gambo 138 kV	15
Salt Pond 138 kV	5
Total Capacitor (MVAR)	**45**

Load flow analysis was then performed for N-1 138 kV transmission line contingencies. For contingencies resulting in undervoltage violations, additional capacitor support was applied at key locations to restore voltages within acceptable post-contingency limits (0.90 to 1.10 pu).

Tables 7 to 9 summarize the results of the contingency analysis and the corresponding capacitor bank mitigation measures.

Table 7: SSD/STB Loop - 138 kV Transmission Line N-1 Contingency Results

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
100L	No Violations	N/A
109L	No Violations	N/A
121L	No Violations	N/A
124L (GLV to Terra Nova Tap (“TNS”))	Undervoltage (<0.90 pu)	Increase GAM capacitor to 25 MVAR
124L (TNS to Port Blandford (“PBD”))	Undervoltage (<0.90 pu)	Increase GAM capacitor to 20 MVAR
124L (PBD to Clarenville (“CLV”))	Undervoltage (<0.90 pu)	Increase GAM capacitor to 25 MVAR
146L	No Violations	N/A
144L	No Violations	N/A
130L	No Violations	N/A
132L	No Violations	N/A
133L	No Violations	N/A
136L	No Violations	N/A
137L	No Violations	N/A
147L	No Violations	N/A
148L	No Violations	N/A
TL210 (STB to GLN)	Undervoltage (<0.90 pu)	Increase GAM capacitor to 25 MVAR and GLN capacitor to 25 MVAR
TL210 (GLN to COB)	No Violations	N/A

Table 8: Burin Peninsula Loop – 138 kV Transmission Line N-1 Contingency Results

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
TL212 (SSD to MKS)	No Violations	N/A
TL212 (MKS to BLA)	Undervoltage (<0.90 pu)	Increase SPO capacitor to 15 MVAR
TL212 (BLA to Linton Lake ("LLK"))	Undervoltage (<0.90 pu)	Increase SPO capacitor to 10 MVAR
TL219	Undervoltage (<0.90 pu)	Increase SPO capacitor to 25 MVAR

Table 9: DLK/STB Loop – 138 kV Transmission Line N-1 Contingency Results

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
TL222	Undervoltage (<0.90 pu)	Add 10 MVAR Cap Bank at BWT L60 138 kV bus
TL223	No Violations	N/A
TL224	Undervoltage (<0.90 pu)	Add 20 MVAR Cap Bank at BWT L60 138 kV bus
TL245	No Violations	N/A

The total installed capacitor capacity required to cover N-1 contingencies across the three loops is:

- SSD/STB loop:
  - GLN = 25 MVAR
  - GAN = 10 MVAR
  - GAM = 25 MVAR
- Burin Peninsula loop:
  - SPO = 25 MVAR
- DLK/STB loop:
  - BWT = 20 MVAR

This results in a total installed capacitor capacity of approximately 105 MVAR.

4.5.3 Combination of 138 kV Transmission Lines and 138 kV Capacitor Banks

This alternative evaluated a combination of 138 kV transmission lines and shunt capacitor banks within the SSD/STB loop to address undervoltage conditions observed under pre-contingency and N-1 contingency scenarios.[12] For this alternative, two configurations were assessed along 138 kV transmission line TL210.[13]

[12] Each option considered included a 1 km long tap connecting Newfoundland Power's 138 kV transmission line 147L to the Glenwood Substation.

[13] TL210 connects Stony Brook to Cobb's Pond and has a length of 85.39 km.

4.5.3.1 Parallel Line Addition Configuration #1: STB to GLN

A 138 kV transmission line with an approximate length of 61.4 km (Darien) was added between STB and GLN running in parallel with TL210. In addition, capacitor banks were added at the 138 kV buses in GAM (15 MVAR) and SPO (5 MVAR) to achieve acceptable pre-contingency voltage limits.

For N-1 transmission line contingencies, additional capacitor support was evaluated to restore voltages. Tables 10 to 12 show the results of the N-1 contingencies and the corresponding capacitor bank mitigation measures.

Table 10: SSD/STB Loop – 138 kV Transmission Line N-1 Contingency Results (STB to GLN)

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
100L	No Violations	N/A
109L	No Violations	N/A
121L	No Violations	N/A
124L (GLV to TNS)	Undervoltage (<0.90 pu)	Increase GAM capacitor to 20 MVAR
124L (TNS to CLV)	Undervoltage (<0.90 pu)	Increase GAM capacitor to 20 MVAR
124L (PBD to CLV)	Undervoltage (<0.90 pu)	Increase GAM capacitor to 20 MVAR
146L	No Violations	N/A
144L	No Violations	N/A
130L	No Violations	N/A
132L	No Violations	N/A
133L	No Violations	N/A
136L	No Violations	N/A
137L	No Violations	N/A
147L	No Violations	N/A
148L	Undervoltage (<0.90 pu)	Increase GAM capacitor to 20 MVAR
TL210 (STB to GLN)	No Violations	N/A
TL210 (GLN to COB)	No Violations	N/A

Table 11: Burin Peninsula Loop – 138 kV Transmission Line N-1 Contingency Results (STB to GLN)

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
TL212 (SSD to MKS)	No Violations	N/A
TL212 (MKS to BLA)	Undervoltage (<0.90 pu)	Increase SPO capacitor to 15 MVAR
TL212 (BLA to LLK)	Undervoltage (<0.90 pu)	Increase SPO capacitor to 15 MVAR
TL219	Undervoltage (<0.90 pu)	Increase SPO capacitor to 25 MVAR

Table 12: DLK/STB Loop – 138 kV Transmission Line N-1 Contingency Results (STB to GLN)

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
TL222	Undervoltage (<0.90 pu)	Add 10 MVAR Cap Bank at BWT L60 138 kV bus
TL223	No Violations	N/A
TL224	Undervoltage (<0.90 pu)	Add 20 MVAR Cap Bank at BWT L60 138 kV bus
TL245	No Violations	N/A

With the addition of a 61.4 km parallel 138 kV line between Stony Brook and Glenwood, the total installed capacitor capacity required to cover N-1 contingencies is reduced to the following:

- SSD/STB loop:
  - GAM = 20 MVAR
- Burin Peninsula loop:
  - SPO = 25 MVAR
- DLK/STB loop:
  - BWT = 20 MVAR

This results in a total installed capacitor capacity of approximately 65 MVAR.

4.5.3.2 Parallel Line Addition Configuration #2: GLN to GAN

A second configuration was evaluated by adding a parallel 138 kV transmission line (Darien) between GLN and GAN with an approximate length of 23.4 km. Capacitor bank additions were then assessed to achieve acceptable pre-contingency and N-1 contingency voltage performance.

Table 13 shows the capacitor bank additions required to achieve acceptable pre-contingency levels in this configuration.

Table 13: Pre-contingency Capacitor Bank Additions

Bus	Capacitor Size (MVAR)
Glenwood 138 kV	10
Gander 138 kV	15
Gambo 138 kV	15
Total Capacitor (MVAR)	**40**

For N-1 contingencies, additional capacitor support was considered for post contingency planning criteria. Tables 14 to 16 show the results of the N-1 contingencies and the corresponding capacitor bank mitigation measures.

Table 14: SSD/STB Loop – 138 kV Transmission Line N-1 Contingency Results (GLN to GAN)

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
100L	No Violations	N/A
109L	No Violations	N/A
121L	No Violations	N/A
124L (GLV to TNS)	Undervoltage (<0.90 pu)	Increase GAM capacitor to 20 MVAR
124 (TNS to CLV)	Undervoltage (<0.90 pu)	Increase GAM capacitor to 20 MVAR
124L (PBD to CLV)	Undervoltage (<0.90 pu)	Increase GAM capacitor to 20 MVAR
146L	No Violations	N/A
144L	No Violations	N/A
130L	No Violations	N/A
132L	No Violations	N/A
133L	No Violations	N/A
136L	No Violations	N/A
137L	No Violations	N/A
147L	No Violations	N/A
148L	No Violations	N/A
TL210 (STB to GLN)	Undervoltage (<0.90 pu)	GLN 20 MVAR GAN 20 MVAR GAM 20 MVAR
TL210 (GLN to COB)	No Violations	N/A

Table 15: Burin Peninsula Loop – 138 kV Transmission Line N-1 Contingency Results (GLN to GAN)

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
TL212 (SSD to MKS)	No Violations	N/A
TL212 (MKS to BLA)	Undervoltage (<0.90 pu)	Add 10 MVAR Cap Bank at SPO 138 kV bus
TL212 (BLA to LLK)	No Violations	N/A
TL219	Undervoltage (<0.90 pu)	Add 20 MVAR Cap Bank at SPO 138 kV bus

Table 16: DLK/STB Loop – 138 kV Transmission N-1 Line Contingency Results (GLN to GAN)

Outage (N-1)	Voltage Performance	Mitigation (Cap Banks)
TL222	Undervoltage (<0.90 pu)	Add 10 MVAR Cap Bank at BWT L60 138 kV bus
TL223	No Violations	N/A
TL224	Undervoltage (<0.90 pu)	Add 20 MVAR Cap Bank at BWT L60 138 kV bus
TL245	No Violations	N/A

With the addition of 23.4 km parallel 138 kV line between Glenwood and Gander, the total installed capacitor capacity required to cover N-1 contingencies is:

- SSD/ STB loop:
  - GLN = 20 MVAR
  - GAN = 20 MVAR
  - GAM = 20 MVAR
- Burin Peninsula loop:
  - SPO = 20 MVAR
- DLK/STB loop:
  - BWT = 20 MVAR

This results in a total installed capacitor capacity of approximately 100 MVAR.

5 Capacitor Bank Switching Analysis

Hydro's Transmission Planning Criteria[14] states that transmission lines and shunt reactive devices (shunt reactor, capacitor or filter bank) shall be specified such that voltage changes due to switching shall not exceed 2.5%.[15] If capacitor banks are added to the system, the size of the capacitor bank must be limited so that the change in voltage during switching does not exceed 2.5%. Table 17 shows the maximum amount of capacitor banks that can be switched at a time while not exceeding this planning criteria.

Table 17: Capacitor Bank Switching Amounts (Cap. Bank only option)

Location	Maximum Switched Amount (MVAR)	Total Required for Mitigation (MVAR)	% Delta V (Maximum Switched amount)
BWT	3	20	2.00%
SPO	6	25	2.36%
GLN	10	25	2.15%
GAN	10	10	2.20%
GAM	8	25	2.05%

Note: Based on this analysis, the capacitor bank options provide the amount of reactive support required to maintain system voltages during pre-contingency and N-1 contingencies. Further study is required to determine the need for a static var compensator (SVC).

[14] As per *NLSO Standard TP-S-007 "Transmission Planning Criteria"*.

[15] Delta %V = (Cap. Bank Switched (MVAR)/ Three Phase Short Circuit Level (MVA)) x System Voltage.

6 Sensitivity Analysis

6.1 147L not tapped into GLN substation

This study assumed that each option considered included a 1 km long tap connecting Newfoundland Power's 138 kV transmission line 147L to the Glenwood Substation. A load flow analysis was conducted to determine the transmission line additions and capacitor bank requirements if this tap was not installed. The load flow analysis showed that tapping 147L into the Glenwood station has little impact on system voltages and is not required to maintain voltage levels. However, there may be other reasons to tap this line, such as improving system reliability.

7 Results and Recommendations

The Sunnyside/Stony Brook 138 kV loop analysis documented herein provides a preliminary technical assessment of potential alternatives for high load growth scenarios where Newfoundland Power's WES GT and GRH GT are not in service.[16]

The analysis was limited to steady state, and did not include any dynamic analysis, or detailed short circuit analysis. Additional analysis is required to determine technical solutions for the Sunnyside/Stony Brook 138 kV loop in base case load forecast scenarios where WES GT and GRH GT are not in service in the 10 year planning horizon.

Further study is required to determine the need for a static var compensator (SVC).

It is noted that Hydro has not prepared any cost estimates associated with the results of this study.

7.1 Transmission Line Solutions

Under peak load conditions, adding parallel[17] lines along TL210 from STB to GLN (61.4 km) and GLN to GAN (23.3 km) is required to eliminate voltage violations within the SSD/STB loop. Similarly, tapping TL219 into MKS and BLA resolves violations in the Burin Peninsula loop and paralleling TL224 addresses issues in the DLK/STB loop.

Under light load conditions, no voltage violations were observed; however, one contingency (loss of TL222) resulted in thermal overloads in TL224 and TL225.[18] This can be mitigated through adding a 66 kV parallel line (1.6 km) along TL225 from DLP to DLK NP.

7.2 Capacitor Bank Solutions

Under peak load conditions, voltage violations observed across the SSD/STB, Burin Peninsula, and DLK/STB loops under pre-contingency and N-1 contingency scenarios can be resolved through the installation of capacitor banks at key locations. This solution requires reactive power support distributed across multiple locations, including GLN (25 MVAR), GAN (10 MVAR), GAM (25 MVAR), SPO (25 MVAR), and BWT (20 MVAR), with a total installed capacity of approximately 105 MVAR.[19]

Under light load conditions, no additional reactive power support is required, as voltage levels remain within acceptable limits for all contingencies.

[16] For comparison, Newfoundland Power's Loop Assessment included a review of base case load forecast scenarios where both WES GT (8 MW) and GRH GT (20 MW) were available for capacity support over the 10 year planning horizon, as well as sensitivity analysis for 93 MW of new large loads and WES GT (15 MW) and GRH GT (30 MW) replacements.

[17] A 559.5 kcmil Darien AAAC conductor was assumed for all parallel lines.

[18] Adding a parallel line to TL224 and/or a Remedial Action Scheme are being considered as part of the Customer 4 System Impact Study.

[19] This alternative required 45 MVAR for pre-contingency (GLN – 15 MVAR, GAN – 10 MVAR, GAM – 15 MVAR, SPO – 5 MVAR).

7.3 Combined Transmission Line and Capacitor Bank Solutions

Under peak load conditions, a combination of transmission line additions and capacitor banks effectively resolves all identified voltage violations across the SSD/STB, Burin Peninsula, and DLK/STB loops.

Multiple configurations of combined solutions were assessed which includes parallel 138 kV lines from STB to GLN and GLN to GAN. However, the addition of a parallel line from STB to GLN (61.4 km) significantly reduces the overall reactive power requirements compared to the capacitor bank only solution. This approach requires total capacitor capacity of approximately 65 MVAR, with approximately 25 MVAR at GAM, 20 MVAR at SPO and 20 MVAR at BWT. [20]

If 138 kV transmission line TL210 is parallelled from GLN to GAN (23.3 km) the total capacitor capacity is approximately 100 MVAR, with approximately 20 MVAR at GLN, 20 MVAR at GAM, 20 MVAR at GAN, 20 MVAR at SPO and 20 MVAR at BWT.

Under light load conditions, no additional reactive power support is required, as system performance remains within acceptable limits.

[20] This alternative required 20 MVAR for pre-contingency (GAM – 15 MVAR, SPO – 5 MVAR).

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Attachment D:

Hatch Report – Burin Peninsula Voltage Regulation

Newfoundland Power

Final Report

For

Burin Peninsula Reactive Power Support Analysis

H364382-00000-200-230-0001
Rev. 0
January 11, 2021

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Newfoundland Power

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Newfoundland Power
Burin Peninsula

Burin Peninsula Reactive Power Support Analysis

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List of Appendices

Appendix A : Burin Peninsula System Single Line Diagram

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1. Background

Newfoundland Power (NL Power) is considering retiring an existing gas turbine in the Burin Peninsula, which provides voltage support to the peninsula 66 kV loop in the event of a loss of one of the supplying 138 kV transmission lines (i.e.,TL212 and TL219). Presently, all of the capacitor banks are on the distribution side (<25 kV), and no capacitor banks are installed at transmission voltages (>66 kV).

The peak load on the 66 kV loop is close to 40 MVA. After modeling the system, NL Power found that upon disconnecting the GT and disconnecting one of the 138 kV transmission lines, it will require reactive power support for the 66 kV loop.

NL Power is investigating the best option for reactive compensation to maintain the voltage on its system within an acceptable range in the event of a loss of one of the 138 kV lines (or a section of the 66 kV loop), considering the retirement of the gas turbine.

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2. Local Reactive Power – Bus Voltage Stability Assessment

To assess the local reactive power – bus voltage stability, the following approach is adopted:

a) **Generation – Load Portfolio Assessment in the Burin Peninsula**: The analysis would consider different loading levels (peak and off-peak) conditions. Special considerations would be given for intermittent interconnected energy resources at the 66 kV loop.

b) **Transmission and Sub-Transmission System Topology and Strength**: N-1 conditions on the 138 kV were considered as well as the impact of the outage events of the upstream 230 kV system supporting Sunnyside 230/138 kV (i.e., TL203 and TL237) and the outage of one of the Sunnyside 230/138 kV transformers.

c) **Post-Transient Analysis PV/QV:** The post-transient analysis would evaluate the impact of the BPS total load increase on the 66 kV system post a single element outage (e.g. an overhead line or a 138/66 kV transformer) while all discrete voltage control devices are locked.

d) **Bus Voltage Criteria**: The bus voltage criteria are as follows:

- Pre-Contingency bus voltage range 0.95 -1.05 pu.
- Post-Contingency bus voltage range: 0.9 -1.1 pu for voltage levels greater than 100 kV and 0.933 -1.075 pu for the distribution voltage levels (e.g., 66 kV).
- Switching step-change voltage: The range of 2% to 3% step-change would be considered when discrete bus voltage control devices are sized (e.g., mechanically switched shunt capacitors' steps).

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3. System Configuration and Methodology

Burin Peninsula System (BPS) is a 66 kV loop originating from the Salt Pond Substation (SPS) 138/66 kV substation (two 138/66 kV transformers). The SPS is supported from Sunnyside 230/138 kV substation by two 138 kV circuits, TL219 and TL212. The BPS total load is forecasted to reach 40 MVA. The following generation resources are currently connected to the loop:

a) Wind turbines with a total generation capacity of 28.418 MW.

b) Gas-fired turbine (GT) unit with a generation capacity of 21.25 MW (planned for retirement).

The voltage stability analysis considered the retirement of the GT unit as well as the intermittency of the interconnected wind turbines' generation. A single line diagram of the system is illustrated in Appendix A.

Table 3-1 lists the outages considered for the post-transient stability analysis. The post transient stability analysis would lock transformers' on-load tap changers (OLTC) and discrete reactive power devices at pre-outages settings. Therefore, the maximum possible reactive power support would be estimated based on system intact (N-0) conditions and considered locked for the post-event conditions.

Table 3-1: List of Contingencies / Outages

Outage / Contingency		
Type	**EQT ID**	**kV**
Line	TL219_TL219	138
BRK	SUN_B3RB1_MD_SUN_B3RB1	138
Load	SUN_T5_MD_SUN_T5	138/25
BRK	SUN_B2B3_MD_SUN_B2B3	138
Line	TL212(A)_TL212(A)	138
Load/Gen	MKS_T1_MD_MKS_T1	138/25
Load only	MKS_25_SL_MKS_25	25
Gen only	PAR_G1_MD_PAR_G1	4.16
Line	TL212(B)_TL212(B)	138
Load	BLA_T1_MD_BLA_T1	138/25
Line	TL212(C)_TL212(C)	138
Load	LLK_T1_MD_LLK_T1	138/12.47
Line	300L_300L (a segment of TL212)	138
Load	MSY_T1_MD_MSY_T1	138/12.47
Line	308L_308L(a segment of TL212)	138
Bus Tie	SPO-138-BT_MD_SPO-138-BTS	138
XFR	SPO_T5_MD_SPO_T5	138/66
BRK	SPO_66_B2B_MD_SPO_66_B2B3	66
Bus Tie	29_MD_29	66
Load	SPO_T1_MD_SPO_T1	66/12.47

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Outage / Contingency		
Type	**EQT ID**	**kV**
Line	302L_302L	66
Line to NEwind	901L_901L	66
XFR to FPD load/gen	LAU_T1_MD_LAU_T1	66/12.47
Line to FPD gen	LAU-01(A)_LAU-01(A)	12.47
Line	305L(B)_305L(B)	66
Load/Gen	WBC_T1_MD_WBC_T1	25/66
Gen only	WBC_01_WBC_01	25
Line	305L(A)_305L(A)	66
Gen	GRT_T1_MD_GRT_T1	66/13.8
Bus Tie	GRH_66-BTS_MD_GRH_66-BTS-	66
Load	GRH_T2_MD_GRH_T2	66/13.04
Line	301L(C)_301L(C)	66
Load	GBE-T1_MD_GBE-T1	66/7.2
Line	301L(B)_301L(B)	66
Load	GAR_T1_MD_GAR_T1	66/13.2
Line	301L(A)_301L(A)	66
Bus Tie	28_MD_28	66
BRK	SPO_T4_D_MD_SPO_T4_D	66
XFR	SPO_T4_MD_SPO_T4	138/66

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4. Analysis Results

4.1 Without Wind Turbines' Generation

To consider the intermittency of the interconnected wind turbines' generation, no generation support was considered from the interconnected wind units to the BPS.

A high-level analysis was conducted for the optimal "single" location of the proposed reactive power support. The analysis started at the 66 kV bus of the SPS because this location would provide reactive power support to the entire 66 kV loop. A shunt capacitor (discrete reactive power support device) was placed at the substation 66 kV bus and sized at 39 Mvar such that the highest bus voltage does not exceed 105% (system intact limit).

Table 4-1 lists under-voltage violations observed following several contingencies. This concludes that a discrete reactive power support device at this location cannot successfully mitigate post-transient under-voltage violations throughout the BPS 66 kV loop.

Table 4-1: Undervoltage Violations – No Wind Generation - 39 Mvar at the SPS 66 kV Bus

Outage		Bus Name	Base kV	V [%]
TL219_TL219	138	N_BLA_25	25	87.67
		N_BLA_138	138	89.09
		N_GAR_12	13.2	80.29
		N_GAR_TAP	66	87.16
		N_GBE_07	7.2	83.86
		N_GBE_66	66	85.59
		N_GRH_12	13.04	78.01
		N_GRH_66(B1	66	83.71
		N_GRH_66(B2)	66	83.71
		N_LAU_12	12.47	82.84
		N_LAU_66	66	85.49
		N_LLK_12	12.47	85.44
		N_LLK_138	138	86.87
		N_MSY_12	12.47	83.43
		N_MSY_138	138	86.75
		N_SPO_12	12.47	86.15
		N_SPO_66(T4)	66	88.95
		N_SPO_66(T5)	66	88.95
		N_SPO_66_(B1)	66	88.95
		N_SPO_66_(B2)	66	88.95
		N_SPO_66_(B3)	66	88.95
		N_SPO_138(B1)	138	86.9
		N_SPO_138(B3)	138	86.9
		N_WBC_25	24.94	82.99
		N_WBC_66	66	84.67
		N_WBC_VR	24.94	82.99
SUN_B3RB1_MD_SUN_B3RB1	138	N_GAR_12	13.2	91.06

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Outage		Bus Name	Base kV	V [%]
		N_GRH_12	13.04	89.92
TL212(B)_TL212(B)	138	N_GRH_12	13.04	92.92
308L_308L	138	N_MSY_12	12.47	89.32
302L_302L	66	N_GAR_12	13.2	88.37
		N_GBE_07	7.2	88.36
		N_GBE_66	66	90
		N_GRH_12	13.04	78.02
		N_GRH_66(B1	66	83.72
		N_GRH_66(B2)	66	83.72
		N_LAU_12	12.47	77.2
		N_LAU_66	66	80.09
		N_WBC_25	24.94	79.24
		N_WBC_66	66	81.01
		N_WBC_VR	24.94	79.24
305L(B)_305L(B)	66	N_GRH_12	13.04	90.12
305L(A)_305L(A)	66	N_GRH_12	13.04	92.82
GRH_66-BTS_MD_GRH_66-BTS-	66	N_GRH_12	13.04	93
301L(C)_301L(C)	66	N_GRH_12	13.04	91.24
301L(B)_301L(B)	66	N_GRH_12	13.04	91.35
301L(A)_301L(A)	66	N_GAR_12	13.2	87.55
		N_GBE_07	7.2	93.28
		N_GRH_12	13.04	89.77

It can be seen from Table 4-1 above that most voltage issues were around the N_GRH, N_GAR, and N_GBE bus vicinity. Therefore, the capacitor was moved to N_GAR_TAP and re-sized accordingly.

The shunt capacitor, placed at N_GAR_TAP, was sized at 31 Mvar, the maximum possible capacity such that the highest bus voltage does not exceed 105% (system intact limit).

Table 4-2 lists under-voltage violations observed following several contingencies.

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Table 4-2: Undervoltage Violations – No Wind Generation – 31 Mvar at N_GAR_TAP

Outage		Bus Name	Base kV	V [%]
TL219_TL219	138	-	-	-
SUN_B3RB1_MD_SUN_B3RB1	138	N_BLA_25	25	89.09
		N_GAR_12	13.2	85.74
		N_GAR_TAP	66	92.66
		N_GBE_07	7.2	88.96
		N_GBE_66	66	90.58
		N_GRH_12	13.04	82.47
		N_GRH_66(B1	66	88.04
		N_GRH_66(B2)	66	88.04
		N_LAU_12	12.47	85.5
		N_LAU_66	66	88.05
		N_LLK_12	12.47	87.22
		N_LLK_138	138	88.62
		N_MSY_12	12.47	85.34
		N_MSY_138	138	88.56
		N_SPO_12	12.47	87.6
		N_SPO_66(T4)	66	90.34
		N_SPO_66(T5)	66	90.34
		N_SPO_66_(B1)	66	90.34
		N_SPO_66_(B2)	66	90.34
		N_SPO_66_(B3)	66	90.34
		N_SPO_138(B1)	138	88.85
		N_SPO_138(B3)	138	88.85
		N_WBC_25	24.94	86.21
		N_WBC_66	66	87.82
		N_WBC_VR	24.94	86.21
308L_308L	138	N_MSY_12	12.47	89.32
302L_302L	66	N_GAR_12	13.2	90.11
		N_GBE_07	7.2	90.4
		N_GBE_66	66	92
		N_GRH_12	13.04	80.36
		N_GRH_66(B1	66	85.99
		N_GRH_66(B2)	66	85.99
		N_LAU_12	12.47	79.74
		N_LAU_66	66	82.51

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Outage		Bus Name	Base kV	V [%]
		N_WBC_25	24.94	81.69
		N_WBC_66	66	83.4
		N_WBC_VR	24.94	81.69
301L(A)_301L(A)	66	N_GAR_12	13.2	90.11
		N_GBE_07	7.2	90.4
		N_GBE_66	66	92
		N_GRH_12	13.04	80.36
		N_GRH_66(B1	66	85.99
		N_GRH_66(B2)	66	85.99
		N_LAU_12	12.47	79.74
		N_LAU_66	66	82.51
		N_WBC_25	24.94	81.69
		N_WBC_66	66	83.4
		N_WBC_VR	24.94	81.69

It can be seen from Table 4-2 above that a discrete reactive power support device at this location cannot mitigate under-voltage violations.

To determine the BPS loading level at which reactive power support is needed considering the intermittency of the interconnected wind turbines' generation, the BPS load was scaled down to 70%. The 70% load case was created by scaling all load MW and Mvar values to 70% of their peak values.

A shunt capacitor was placed at the SPS 66 kV bus and sized at 26 Mvar, the maximum possible capacity such that the highest bus voltage does not exceed 105% (system intact limit).

Table 4-3 lists under-voltage violations observed following several contingencies imposed on the 70% load case.

Table 4-3: Undervoltage Violations – No Wind Generation – 26 Mvar at the SPS 66 kV Bus – 70% Load

Outage		Bus Name	Base kV	V [%]
308L_308L	138	N_GRH_12	13.04	90.61
		N_LAU_12	12.47	91.55
		N_LAU_66	66	93.15
		N_WBC_25	24.94	92.63
		N_WBC_VR	24.94	92.63

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It can be seen from Table 4-3 above that a 26 Mvar discrete reactive power device at this location may be able to mitigate the 66 kV under-voltage violations at 70% of the BP peak loading conditions. Besides, the lowest 66 kV bus voltage was reported at N_LAU_66- 66 kV bus. Therefore, the discrete reactive power support device was moved to N_LAU_A shunt capacitor was placed at N_LAU_66 and sized at 19 Mvar, the maximum possible capacity such that the highest bus voltage does not exceed 105% (system intact limit).

Table 4-4 lists under-voltage violations observed following several contingencies imposed on the 70% load case.

Table 4-4: Undervoltage Violations – No Wind Generation – 19 Mvar at N_LAU_66 – 70% Load

Outage		Bus Name	Base kV	V [%]
TL219_TL219	138	N_GAR_12	13.2	89.39
		N_GRH_12	13.04	91.08
SUN_B2B3_MD_SUN_B2B3	138	N_GRH_12	13.04	90.61
		N_LAU_12	12.47	91.55
		N_LAU_66	66	93.15
		N_WBC_25	24.94	92.63
		N_WBC_VR	24.94	92.63

It can be seen from Table 4-4 above that a 19 Mvar discrete reactive power support at this location may be able to mitigate the under-voltage violations at 70% of the BP peak loading conditions.

4.2 With Wind Turbines' Generation

To evaluate the impact of the wind turbine generation levels on the required reactive power support/bus voltage stability of the BPS, interconnected wind turbines' generation was assumed at their full capacity (28.418 MW).

A shunt capacitor was placed at the SPS 66 kV bus and sized at 35 Mvar. This is the maximum possible capacity such that the highest bus voltage does not exceed 105% (system intact limit). Table 4-5 lists under-voltage violations observed following several contingencies.

Table 4-5: Undervoltage Violations – With Wind Generation – 35 Mvar at the SPS 66 kV Bus

Outage		Bus Name	Base kV	V [%]
308L_308L	138	N_MSY_12	12.47	89.32
302L_302L	66	N_GRH_12	13.04	91.82
301L(A)_301L(A)	66	N_GAR_12	13.2	90.2
		N_GRH_12	13.04	92.47

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Table 4-5 shows that a discrete reactive power support device at this location may be able to support the BPS 66 kV system considering the maximum generation capacity of the interconnected wind turbine generation resources. The reported 12 kV under-voltage bus violations may be mitigated by proper 66/12 kV transformers OLTC settings.

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5. Conclusion and Recommendations

NL Power is considering retiring an existing gas turbine in the Burin Peninsula, which provides voltage support to the peninsula 66 kV loop in the event of a loss of one of the supplying 138 kV transmission lines (or a section of the 66 kV loop). The peak load on the 66 kV loop is close to 40 MVA. After modeling the system, the analysis depicted in this review study supported the findings of the NL Power that upon disconnecting the GT and disconnecting one of the 138 kV transmission lines, it will require approximately 35 Mvar of reactive power support at the SPS 66 kV bus. While this sizing of the reactive power support considered full generation output of the 28.418 MW interconnected generation units to the BPS, a discrete reactive power support device may be able to mitigate under-voltage bus voltage violations post the studied N-1 system events.

However, and considering the intermittent nature of the wind turbine generation resources, the required reactive power support is estimated to be greater than 40 Mvar when there is no support from the interconnected wind turbine units to the BPS 66 kV loop. Also, this reactive power support must be continuous (e.g. STATCOM) to mitigate post-transient under-voltage bus violations in the BP 66 kV loop. Otherwise, near voltage collapse conditions are predicted without the proper sizing and type selection of the reactive power support while considering the BPS peak loading conditions.

The analysis in this study also concluded that a 26 Mvar discrete reactive power support device (at the SPS 66 kV bus) will be able to mitigate the BPS 66 kV under-voltage bus violations post N-1 system events when the BPS loading conditions are at 70% of the forecasted peak loading levels. This was estimated with no generation support from the interconnected wind turbine generators to the BPS.

In summary, a continuous reactive power support device (sized greater than 40 Mvar) must be considered post the retirement of the GT unit to address predicted voltage instability concerns.

Furthermore, considering the impact of the GT retirement on the fault current levels/system strength of the BPS, the following studies are recommended:

a) Harmonic distortion levels' analysis: The retirement of the GT unit has significantly reduced the fault current levels, and may trigger lower-order harmonic resonances. An assessment for the harmonic emissions from the interconnected wind turbines and total harmonic distortion levels needs to be conducted in compliance with the IEEE 519-2014 guidelines. It should be noted that the addition of an SVC would contribute to the harmonic emission levels as well as increasing the risk of lower-order harmonic resonance.

b) Flicker analysis: Detailed flicker analysis and emissions should be conducted in compliance with the IEC 61000-3-7 emission limits. The addition of a continuous reactive

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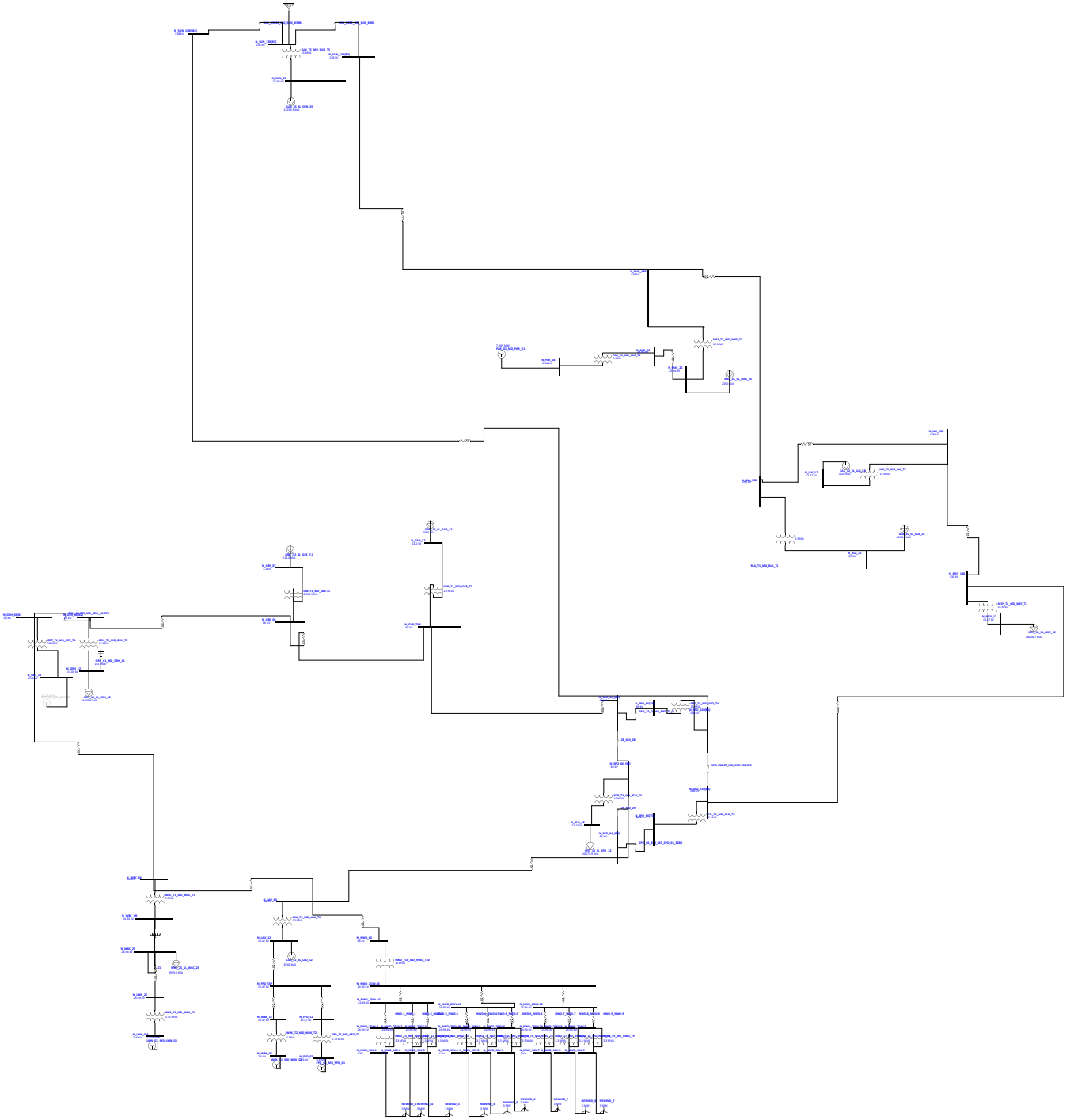
power support device such as a STATCOM will provide proper mitigation for possible flicker issues arising from the retirement of the GT turbine unit.

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Appendix A:
Burin Peninsula System Single Line Diagram

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One-Line Diagram - OLV1 (Edit Mode)



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Attachment E:

Summary of Net Present Value Parameters

Economic Evaluation
Major Inputs and Assumptions

Income Tax

Income tax expense reflects a statutory income tax rate of 30%.

Capital Cost Allowance ("CCA") rates are provided in Table E-1.

Table E-1
CCA Rates by Class

Class	Rate	Details
47	8.00%	All transmission and substation equipment not otherwise noted.
48	15.00%	Expenditures related to new generation equipment at existing generating facilities.

Operating and Capital Lifecycle Costs

Operating and maintenance ("O&M") costs, as well as sustaining capital costs, were estimated in 2026 dollars and are escalated yearly using the GDP Deflator for Canada.[1]

Non-fuel related O&M costs, as well as sustaining capital costs, are provided in Table E-2.

Table E-2
Annual O&M and Sustaining Capital Cost Estimates
($000s)

Facility	Fixed O&M	Variable O&M	Average Sustaining Capital Cost
Wesleyville	225	89	377
Greenhill	364	113	703

The price of diesel fuel assumed for the Net Present Value ("NPV") analysis is $2.50/L in 2026 dollars and is escalated yearly using the GDP Deflator for Canada. This estimate considers the existing price of diesel fuel in the Study Area and a forecast decline in the price of oil in 2027.[2] For the purposes of the NPV analysis, a conservatively high diesel fuel price assumption was adopted to reduce the risk of understating the costs associated with fuel consumption.

[1] Based on the Signal49 Research GDP deflator, medium term forecast dated February 6, 2026, and long term forecast dated March 27, 2026.

[2] The price of diesel fuel in Central Newfoundland and the Burin Peninsula on September 30, 2026 was approximately $2.71/L. See the Board's *Petroleum Pricing Order Effective September 30, 2026*. The price of brent crude oil is forecast to decrease from $91 in 2026 to $74 in 2027, or approximately 19%. See *U.S. Energy Information Administration Short-Term Energy Outlook – September 2026,* page 2.

Expected average annual fuel-consumption hours for the facilitates are provided in Table E-3.

Table E-3 [3]
Expected Average Annual Fuel-Consumption Hours for the CTG Facilities (2032-2066)

Operation Function	Wesleyville (Alt. 1)	Greenhill (Alt. 1)	Hydro's Equivalent Replacement (Alt. 2)
Unplanned Transmission Support	37	36	34
Planned Transmission Support	44	14	-
System Peak Support	12	12	12
Monthly Test Runs	12	12	-
Total	105	74	46

Average Incremental Cost of Capital

The NPV analysis utilizes Newfoundland Power's weighted average incremental cost of capital ("WAICC") of 6.57% as the discount rate.

The derivation of the Company's WAICC is provided in Table E-4.

Table E-4
Newfoundland Power's Average Incremental Cost of Capital ($000s)

	Capital Structure	Return	Weighted Cost
Debt	55.00%	4.913%	2.70%
Common Equity	45.00%	8.600%	3.87%
Total	100.00%		6.57%

[3] Based on the historical T-SAIDI data of transmission supply availability to the Gambo – Wesleyville 66 kV transmission system; Hydro's historical worst-case annual forced outage duration for the SSD transformers; a LIL forced outage coinciding with a winter IIS peak greater than 1,200 MW, assuming a 5% LIL forced outage rate; and historical annual worst-case planned local support requirements. It is assumed that Hydro's replacement generation capacity would not operate for local support requirements, and Hydro monthly test runs were excluded from the analysis to conservatively assess fuel requirements under Alternative 2.

Present Worth Analysis

Table E-5 provides the Present Worth Analysis of Alternative 1 from 2027 to 2066.

Table E-5
Present Worth Analysis of Alternative 1

Year	Generation (Thermal)	Transmission	Substation	Capital Revenue Requirement	Operating Costs	Net Benefit	Present Worth Benefit	Total Present Worth Benefit
2027	71,195,000	0	0	6,763,009	0	-6,763,009	-6,763,009	-77,786,560
2028	5,565,000	0	0	8,023,447	0	-8,023,447	-7,528,804	-83,491,949
2029	8,886,000	0	0	8,594,496	0	-8,594,496	-7,567,466	-92,040,479
2030	71,126,000	0	659,000	15,244,951	0	-15,244,951	-12,595,666	-157,399,259
2031	76,933,000	0	7,725,000	23,805,027	0	-23,805,027	-18,455,627	-230,040,462
2032	110,945	0	0	24,083,865	3,773,542	-27,857,406	-20,265,898	-232,874,563
2033	112,814	0	0	23,092,960	3,837,107	-26,930,067	-18,383,477	-235,578,740
2034	114,711	0	0	22,188,738	3,901,640	-26,090,378	-16,712,276	-238,158,881
2035	116,628	0	0	21,358,274	3,966,837	-25,325,111	-15,221,997	-240,620,413
2036	118,561	0	0	20,590,578	4,032,581	-24,623,159	-13,887,660	-242,968,474
2037	120,525	0	0	19,876,302	4,099,404	-23,975,706	-12,688,835	-245,208,289
2038	122,532	0	0	19,207,494	4,167,641	-23,375,134	-11,608,323	-247,345,004
2039	124,574	0	0	18,577,390	4,237,101	-22,814,492	-10,631,418	-249,383,408
2040	926,462	0	0	18,056,954	4,308,155	-22,365,109	-9,779,496	-251,713,425
2041	521,559	0	0	17,534,383	4,380,169	-21,914,552	-8,991,726	-253,746,356
2042	130,928	0	0	16,989,606	4,453,233	-21,442,839	-8,255,774	-255,516,432
2043	133,118	0	0	16,459,285	4,527,725	-20,987,010	-7,582,128	-257,205,167
2044	135,353	0	0	15,946,803	4,603,722	-20,550,525	-6,966,722	-258,816,390
2045	4,266,490	0	0	15,845,551	4,681,138	-20,526,689	-6,529,644	-261,800,362
2046	2,238,933	0	0	15,608,229	4,759,524	-20,367,753	-6,079,653	-263,957,158
2047	142,276	0	0	15,137,929	4,839,222	-19,977,151	-5,595,440	-265,356,479
2048	144,659	0	0	14,645,486	4,920,255	-19,565,740	-5,142,354	-266,691,519
2049	147,081	0	0	14,163,717	5,002,644	-19,166,361	-4,726,835	-267,965,231
2050	23,553,196	0	0	15,935,880	5,086,414	-21,022,294	-4,864,922	-275,145,891
2051	11,973,797	0	0	16,863,847	5,171,586	-22,035,433	-4,785,005	-279,132,798
2052	154,594	0	0	16,421,753	5,258,184	-21,679,937	-4,417,574	-280,238,919
2053	157,183	0	0	15,807,712	5,346,232	-21,153,944	-4,044,662	-281,294,228
2054	159,815	0	0	15,213,532	5,435,755	-20,649,286	-3,704,768	-282,301,060
2055	162,491	0	0	14,636,243	5,526,776	-20,163,019	-3,394,506	-283,261,640
2056	165,212	0	0	14,073,321	5,619,322	-19,692,643	-3,110,928	-284,178,095
2057	167,978	0	0	13,522,618	5,713,418	-19,236,036	-2,851,456	-285,052,450
2058	170,791	0	0	12,982,308	5,809,089	-18,791,397	-2,613,817	-285,886,641
2059	173,651	0	0	12,450,837	5,906,362	-18,357,199	-2,396,004	-286,682,511
2060	6,550,337	0	0	12,538,246	6,005,264	-18,543,510	-2,271,109	-288,301,641
2061	3,419,769	0	0	13,918,185	6,105,822	-20,024,008	-2,301,241	-289,436,232
2062	182,521	0	0	10,076,634	6,208,064	-16,284,698	-1,756,127	-290,127,383
2063	185,578	0	0	9,568,288	6,312,018	-15,880,307	-1,606,942	-290,786,786
2064	188,685	0	0	10,244,205	6,417,713	-16,661,918	-1,582,090	-291,415,897
2065	191,845	0	0	8,045,096	6,525,178	-14,570,273	-1,298,192	-292,016,109
2066	195,057	0	0	4,055,202	6,634,443	-10,689,645	-893,716	-292,588,749

Table E-6 provides the Present Worth Analysis of Alternative 2 from 2027 to 2066.[4]

Table E-6
Present Worth Analysis of Alternative 2

Year	Generation (Thermal)	Transmission	Substation	Capital Revenue Requirement	Operating Costs	Net Benefit	Present Worth Benefit	Total Present Worth Benefit
2027	77,517,961	0	0	7,363,645	0	-7,363,645	-7,363,645	-84,694,930
2028	6,059,238	2,011,000	1,654,419	9,079,654	0	-9,079,654	-8,519,897	-94,886,885
2029	9,674,093	9,772,000	18,918,792	12,422,228	0	-12,422,228	-10,937,789	-133,382,705
2030	77,443,922	9,281,000	27,223,285	23,231,387	0	-23,231,387	-19,194,210	-238,267,018
2031	83,765,564	9,441,000	4,458,000	33,324,449	0	-33,324,449	-25,835,871	-322,352,839
2032	110,945	0	0	33,474,866	2,518,907	-35,993,773	-26,184,998	-324,274,210
2033	112,814	0	0	32,171,838	2,561,339	-34,733,176	-23,710,172	-326,107,499
2034	114,711	0	0	30,972,511	2,604,415	-33,576,926	-21,507,809	-327,856,699
2035	116,628	0	0	29,862,067	2,647,936	-32,510,003	-19,540,572	-329,525,488
2036	118,561	0	0	28,827,852	2,691,821	-31,519,672	-17,777,349	-331,117,350
2037	120,525	0	0	27,859,053	2,736,427	-30,595,480	-16,192,265	-332,635,826
2038	122,532	0	0	26,946,435	2,781,976	-29,728,411	-14,763,423	-334,084,406
2039	124,574	0	0	26,082,096	2,828,342	-28,910,438	-13,472,093	-335,466,337
2040	926,462	0	0	25,335,998	2,875,772	-28,211,770	-12,336,040	-337,170,021
2041	521,559	0	0	24,595,450	2,923,842	-27,519,293	-11,291,399	-338,605,408
2042	130,928	0	0	23,839,597	2,972,614	-26,812,211	-10,323,052	-339,805,427
2043	133,118	0	0	23,104,402	3,022,338	-26,126,740	-9,438,995	-340,950,300
2044	135,353	0	0	22,392,629	3,073,068	-25,465,696	-8,632,988	-342,042,624
2045	4,266,490	0	0	22,097,115	3,124,744	-25,221,860	-8,023,202	-344,531,499
2046	2,238,933	0	0	21,670,073	3,177,068	-24,847,141	-7,416,723	-346,215,942
2047	142,276	0	0	21,014,152	3,230,268	-24,244,420	-6,790,668	-347,164,608
2048	144,659	0	0	20,339,796	3,284,359	-23,624,155	-6,209,005	-348,069,695
2049	147,081	0	0	19,679,471	3,339,356	-23,018,826	-5,676,935	-348,933,205
2050	23,553,196	0	0	21,276,119	3,395,273	-24,671,392	-5,709,386	-355,722,505
2051	11,973,797	0	0	22,031,329	3,452,127	-25,483,456	-5,533,745	-359,336,031
2052	154,594	0	0	21,418,982	3,509,933	-24,928,915	-5,079,597	-360,085,923
2053	157,183	0	0	20,636,963	3,568,707	-24,205,670	-4,628,156	-360,801,367
2054	159,815	0	0	19,876,873	3,628,465	-23,505,338	-4,217,183	-361,483,945
2055	162,491	0	0	19,135,558	3,689,223	-22,824,781	-3,842,621	-362,135,168
2056	165,212	0	0	18,410,323	3,750,999	-22,161,323	-3,500,916	-362,756,476
2057	167,978	0	0	17,698,871	3,813,810	-21,512,681	-3,188,934	-363,349,243
2058	170,791	0	0	16,999,235	3,877,672	-20,876,907	-2,903,904	-363,914,780
2059	173,651	0	0	16,309,738	3,942,604	-20,252,342	-2,643,360	-364,454,338
2060	6,550,337	0	0	16,240,308	4,008,623	-20,248,931	-2,479,980	-365,828,930
2061	3,419,769	0	0	17,599,147	4,075,747	-21,674,894	-2,490,968	-366,730,216
2062	182,521	0	0	13,306,725	4,143,995	-17,450,721	-1,881,870	-367,198,781
2063	185,578	0	0	12,648,334	4,213,387	-16,861,721	-1,706,252	-367,645,821
2064	188,685	0	0	13,279,595	4,283,940	-17,563,535	-1,667,701	-368,072,325
2065	191,845	0	0	10,780,514	4,355,674	-15,136,188	-1,348,614	-368,479,237
2066	195,057	0	0	6,331,627	4,428,610	-10,760,237	-899,618	-368,867,457

[4] For the NPV analysis for Alternative 2, Hydro's 2025 overnight capital cost for their replacement capacity unit was broken out over five years and escalated accordingly based on the same percent split utilized by Newfoundland Power in Alternative 1 for the WES and GRH generation equipment.

APPENDIX D:

Generation Technology Assessment

Generation Technology Assessment

Prepared for

Newfoundland Power, Inc.

Greenhill and Wesleyville Sites

Prepared by Sargent & Lundy

Report SL-022730

Final – Revision 2

September 10, 2026

Project 14934.002

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ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this document has been prepared, reviewed, and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASQC Q9001 Quality Management Systems.

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ACRONYMS AND ABBREVIATIONS

Acronym/Abbreviation	Definition/Clarification
AACE	Association for the Advancement of Cost Engineering
AC	Alternating Current
AEI	Associated Electrical Industries
AQS	Air Quality Standards
AVR	Automatic Voltage Regulator
BACT	Best Available Control Technology
BESS	Battery Energy Storage System
BMS	Battery Management System
CAD	Canadian Dollar
CER	Clean Electricity Regulations
CO2	Carbon Dioxide
CT(G)	Combustion Turbine (Generator)
DC	Direct Current
DLE	Dry Low Emissions
EOH	Equivalent Operating Hours
EPC	Engineering, Procurement and Construction
FID	Final Investment Decision
FOM	Fixed Operations and Maintenance
FOR	Forced Outage Rate
G&A	General and Administrative
GE	General Electric
GRH	Greenhill Generation Site
HVAC	Heating, ventilation, air conditioning
HVDC	High Voltage Direct Current
IIS	Island Interconnected System
kV	Kilovolt
LIL	Labrador Island Link

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Acronym/Abbreviation	Definition/Clarification
LOLE	Loss of Load Expectation
LTSA	Long Term Service Agreement
MCC	Motor Control Center
MW	Megawatt
NLIS	Newfoundland Labrador Interconnected System
NOx	Nitrogen Oxide Gas
NP	Newfoundland Power
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
ONC	Overnight Capital Cost
PCS	Power Conversion System
PT	Power Turbine
QC	Quality Control
RICE	Reciprocating Internal Combustion Engine
RR	Rolls Royce
RRAS	Reliability and Resource Adequacy Study
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SoC	State of Charge
VOM	Variable Operations and Maintenance
WES	Wesleyville Generation Site

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1. INTRODUCTION

1.1. BACKGROUND AND SCOPE

Newfoundland Power engaged Sargent & Lundy (S&L) to perform a generation technology and cost assessment that considers various replacement generation options for Newfoundland Power's Greenhill (GRH) and Wesleyville (WES) generation sites. This report provides a technology, cost, and economic assessment comparing various thermal generation / energy storage technologies that could replace the existing generators at the two sites. The locations of the two sites are shown in Figure 1-1 below.

Figure 1-1 — Greenhill and Wesleyville Locations



Newfoundland Power has undertaken a system planning study and a condition assessment of the existing generation assets at the GRH and WES sites. The system planning study identified transmission undervoltage and transformer loading constraints under certain contingency events following the retirement of the existing units. The condition assessment was completed by Stantec Consulting Ltd. and determined that the existing generation units are at end-of-life. These assessments provide the context for the replacement generation options evaluated in this report.

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S&L has reviewed current industry offerings for thermal generation (capable of diesel firing) and energy storage within the approximately 15- to 30-MW size range and provides an overview of the available options, with a focus on the following resource categories:

- Combustion turbine (CT) generator solution utilizing modular (i.e., skid-mounted) units
- Combustion turbine solution utilizing traditional units
- Reciprocating internal combustion engine (RICE) solution
- Battery energy storage system (BESS) solution

The results of the cost estimations and the recommended resource can be found in Sections 6 and 8, respectively.

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2. ELECTRICAL SYSTEM OVERVIEW

Newfoundland Power and Newfoundland and Labrador Hydro (NL Hydro) are the two electric utilities serving the island of Newfoundland and together operate the Newfoundland Island Interconnected System (IIS). The electrical systems owned and operated by the two utilities on the IIS are fully interconnected. As part of their coordinated planning approach, Newfoundland Power and NL Hydro complete annual joint studies to identify system constraints and evaluate options to maintain reliable service to customers.

Figure 2-1 — Newfoundland Transmission System[1]



The island of Newfoundland is geographically isolated from the rest of the North American power grid. Electricity supply on the IIS is provided by a mixture of on-island and off-island sources of generation. On-island sources of generation include NL Hydro's 600-MW Bay d'Espoir generating station in central Newfoundland and other NL Hydro and Newfoundland Power generation sources located throughout the

[1] System Information — Newfoundland & Labrador Hydro (nlhydro.com)

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IIS. Off-island sources of generation primarily include the 824 MW Muskrat Falls Project, which is connected to the IIS via the Labrador-Island Link (LIL) high-voltage direct current (HVDC) transmission line. The IIS is also connected to the Nova Scotia grid via the Maritime Link (ML) HVDC transmission line. Even with the off-island Muskrat Falls project, local generation on the island continues to play an important role in providing reliable electricity supply, particularly under peak demand and contingency conditions.

Within this context, recent Newfoundland Power system planning work identified transmission undervoltage conditions and transformer loading constraints under certain contingency events following the retirement of aging thermal generation assets at the GRH and WES sites. In response, Newfoundland Power is proposing replacement generation at these locations as an alternative solution to address the identified system constraints. In addition to mitigating the observed violations, replacement generation at GRH and WES would also provide additional operational flexibility to support peak demand periods and system reliability during emergency conditions.

Accordingly, the generation options evaluated in this report are considered within the broader context of the IIS. NL Hydro's Muskrat Falls Generating Station, together with the LIL and ML HVDC interconnections, represents a significant component of the province's generation and transmission system and enables energy transfers across the Newfoundland and Labrador Interconnected System. Local generation on the island complements these large-scale resources by providing voltage support, contingency response, and operational resilience at specific locations within the transmission system.

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3. EXISTING SITE OVERVIEWS AND CURRENT INFRASTRUCTURE

3.1. SITE OVERVIEWS

Newfoundland Power operates four liquid fueled combustion turbine generators located on the Island of Newfoundland, including the units located at the Greenhill site and at the Wesleyville site. The CTs are utilized as emergency back-up power generators and for electrical power system support. Both units at Greenhill and Wesleyville were originally purchased in the 1969 to 1975 timeframe and have undergone a number of equipment upgrades and modernization over the years.

Greenhill is a 25-MW unit located in the community of Grand Bank, off Route 210 on the Burin Peninsula, on an approximately two-acre site. There are two older fuel storage tanks, installed in 2002, and a third tank installed in 2014—each with a capacity of 100,000 litres. The power plant is connected to the island grid via transmission lines 301L and 305L, which operate at 66 kV.

Figure 3-1 — Aerial View of Greenhill



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Similarly, Wesleyville is a 14.7-MW CT located in the community of New-Wes-Valley, off Route 320 on a 0.6-acre site. A new building was constructed in 2003 when the unit was relocated from Salt Pond, Burin. It is connected to the island grid via transmission line 116L, which operates at 66 kV.

Figure 3-2 — Aerial View of Wesleyville



3.1.1. Geographic & Meteorological Characteristics

Both the Greenhill and Wesleyville generation sites are located in rural coastal areas of Newfoundland, within established communities that are accessible via provincial highways. While the sites are not located near major urban centers, the facilities have well-established infrastructure and access to necessary services. Nevertheless, their coastal location introduces a range of physical, climatic, and logistical considerations that can affect field work, construction, operations, and travel.

The generation sites have cool, maritime-influenced climates typical of coastal Newfoundland, with a relatively short summer season and long, cold, snowy winters, which contributes to a shortened construction window. Storms, high winds, and rapid weather changes can periodically disrupt outdoor work, equipment mobilization, and travel. Winter conditions require additional planning measures to ensure safe access and proper construction sequencing.

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The northern terrain is dominated by boreal forests, scrub, and wetlands; bogs and peatlands are numerous, which can lead to poor bearing capacity. However, the existing generation facilities are situated on developed sites with previously constructed foundations, access roads, and work areas. Civil works associated with new construction are expected to be focused within, or immediately adjacent to, the existing plant footprints and are not anticipated to require extensive overland access or development of uncultivated terrain. Access to water supply at both sites is limited to domestic use

Transporting large or oversized equipment to the sites may require additional coordination, route planning, and schedule flexibility, consistent with past construction and maintenance activities undertaken by Newfoundland Power at these facilities.

Communications and emergency response capabilities are comparable to those serving other rural communities in Newfoundland, though cellular coverage can be inconsistent and response times can be longer than in urban centers. Major roadways are paved, but many secondary and tertiary roads are dirt or gravel.

3.2. GREENHILL PLANT

S&L visited the Greenhill power plant the week of March 9, 2026, to gain familiarity with the existing site conditions, facilities, and unit configurations relevant to the technology assessment. The 25-MW Greenhill CT Power Plant consists of a Rolls Royce (RR) Industrial Olympus “C” gas generator coupled with a Curtis-Wright power turbine (PT), and a Brush AC generator. The plant was originally commissioned in 1975 and has been in standby mode for most of its operating life, with limited service as a synchronous condenser. The Olympus combustion turbine generator is fired with liquid fuel (diesel) only and does not utilize any form of emission controls or nitrogen oxide gas (NO_X) abatement. The electrical generator power output is stepped up from 13.8 kV to 66 kV through a single step-up transformer in the substation for transmission to the local Newfoundland Power grid.

The condition assessment completed by Stantec concluded that the Greenhill CT has reached the end of its service life and is recommended for retirement.

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Figure 3-3 — Greenhill Turbine and Generator



Left: Curtis-Wright Power Turbine; Right: Brush Generator & Coupling (Photos – S&L 2026)

Figure 3-4 — Greenhill Exhaust Stack and Breaker Building



Left: Exhaust Stack; Right: Separate Breaker Building (Photos Newfoundland Power – 2015)

3.3. WESLEYVILLE PLANT

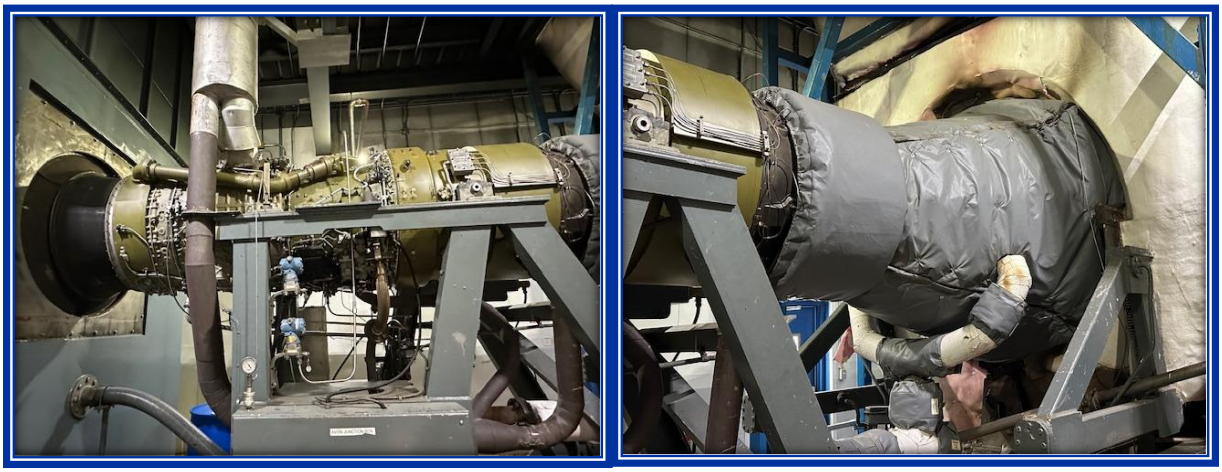
S&L also visited the Wesleyville power plant the week of March 9, 2026, to gain familiarity with the existing site conditions, facilities, and unit configuration relevant to the technology alternatives assessment. The Wesleyville power plant was originally installed in Salt Pond, Burin, in 1969. It was relocated to its current site in the 2003 / 2004 timeframe. The relocation project included significant upgrades to balance of plant systems, including a new building to accommodate the equipment. The plant consists of a single Rolls Royce AVON Mark 1533-52L gas turbine generator, an AEI (Associated Electrical Industries) size B AP1

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power turbine, and an AEI speed reduction (4:1) gearbox, driving a 1,200 rpm AEI type AG 80/100 14.7 MW generator, which was manufactured in 1966. This unit cannot operate as a synchronous condenser.

The condition assessment completed by Stantec concluded that the Wesleyville CTG has reached the end of its service life and is recommended for retirement.

Figure 3-5 — Wesleyville Avon CTG



Left: Turbine section; Right: Close-up of exhaust flange (Photos - S&L 2026)

Figure 3-6 — Wesleyville Generator & Gearbox



Left: AEI generator (Photo - S&L 2026); Right: Speed reduction gearbox (Photo – Newfoundland Power 2015)

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4. REPLACEMENT TECHNOLOGY ASSESSMENT

Newfoundland Power is seeking to replace its current over 50-year-old combustion turbines at GRH and WES with comparably-sized generation resources that can meet the following key requirements:

- Units are reliable in the harsh weather conditions that can define the winter season along the Newfoundland coasts
- Units are capable of quickly starting and ramping
- The units are well-suited to providing needed grid support and peaking services
    - Related to grid support, the unit needs to be able to provide synchronous condensing capability or equivalent electrically
- Unit can support the system in an emergency, such as extended transmission outages and supply shortfall scenarios, and is capable of sustained operation over prolonged periods
- For thermal technologies considered, the units need to be able to operate on diesel fuel with minimal process water consumption

The following types of resources are considered as replacement options for GRH and WES. Characteristics and pros / cons of each are described in the following subsections.

- Combustion Turbines
    - Modular Units
    - Traditional
- Reciprocating Internal Combustion Engines
- Battery Energy Storage Systems

4.1. COMBUSTION TURBINES

Combustion turbines are a very common generating resource type in the power industry. Both of the existing units at GRH and WES are combustion turbines. A combustion turbine (or gas turbine) operates using a Brayton thermodynamic cycle, converting the chemical energy from fuel into mechanical energy. The technology has three primary sections: a compressor, a combustion chamber, and a turbine. Ambient air is drawn into the unit and compressed in the compressor section. From there it is mixed with fuel – which would be diesel fuel at the GRH and WES sites. Combustion of the fuel increases the pressure of the air inside the unit, which drives the turbine blades, spinning them at high speeds. This rotation drives the

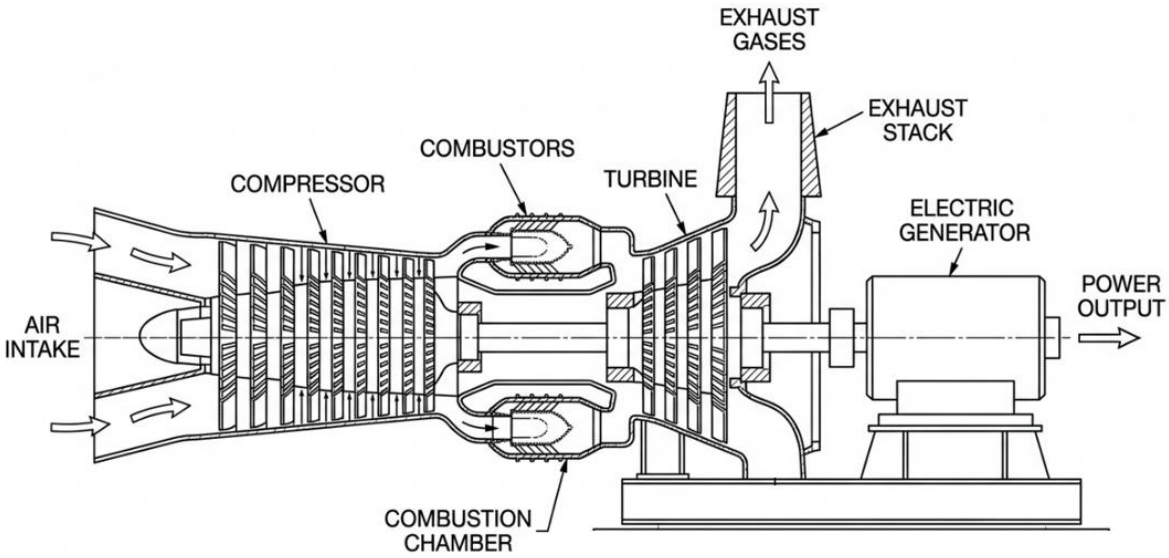
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compressor at the front of the unit and also spins the electric generator connected to the unit, producing power.

Combustion turbines come in various sizes – larger units (100 MW or more in size) frequently are used to provide baseload generation for electrical systems, while smaller units – like those that would be installed in GRH and WES – are used to provide peaking generation, system backup, and grid support services. Combustion turbines are compact, power-dense, and can start up quickly.

Figure 4-1 shows the key sections of a combustion turbine.

Figure 4-1 — Gas Combustion Turbine Schematic



Some characteristics of smaller combustion turbines, similar to those that would be installed at GRH and WES are listed below:

- CTs have high power density, with a small land footprint they can produce a higher number of MWs.
- Units are well suited to providing peaking generation, backup support, and ancillary services support, including increasing local fault levels, and supporting voltage stability when operating.
- Heat rates (efficiencies) are typically in the range of 9,500–10,000 Btu/kWh (ISO, HHV).
- Units typically experience some output / heat rate degradation with use.
- When equipped with a clutch, CTs can be used as synchronous condensers, which allows for short-circuit current, improved fault levels, and system support when spinning.
- Lead times for CTs are currently high—many OEMs are quoting three- to four-year lead times for CT delivery.

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4.1.1. Modular Units

Modular CTs are pre-assembled offsite and shipped directly to the location, minimizing the civil work and on-site labor requirements. Units are mounted and transported on skids, simplifying installation and reducing construction complexity. The smaller footprint makes them well-suited for tightly constrained sites. By shifting a portion of fabrication and assembly offsite, modular CTs can also reduce installation duration and overall construction schedules. This type of CT can be an effective choice for applications like Newfoundland Power's, where the construction season can be short due to weather conditions.

Some common manufacturers and types of units that might fit Newfoundland Power's needs include the list below. Each is dual fuel, meaning that they can operate on diesel.

- Solar Turbines, unit types include the PGM130 (utilizing the Titan 130)
- Baker Hughes, unit types include the NovaLT16
- Siemens, unit types include the SGT-400

There are other manufacturers / units that Newfoundland Power might consider. A modular combustion turbine would be expected to operate for 30 to 40 years based on the low number of expected annual operating hours.[2] Figure 4-2 shows the Solar Turbines' PGM130 for illustrative purposes.

Figure 4-2 — Solar Turbines PGM130 Power Generation Module (Cutaway View)[3]



[2] Under certain circumstances CTs may be capable of operating beyond their design life, with proper maintenance, periodic overhauls, and relatively low operating hours (which would be expected for the GRH and WES sites). As units age, typical challenges include navigating technology obsolescence and diminished access to replacement parts.
[3] https://www.solarturbines.com/en_US/solutions/power-generation/power-generation-modules.html

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Modular units are occasionally used in the industry as a short-term power solution[4]; however, they can be used in permanent applications provided they are adequately designed. For long-term use, it would be important that the plant be designed to withstand harsh winters, repeated freeze-thaw cycles, high winds, and other similar elements that define the Newfoundland coastal climate.

4.1.2. Traditional Units

A traditional unit is also a strong choice to address long-term, permanent backup power needs. The typical method of installation includes installing the turbine and its supporting infrastructure from the ground up, inside a permanent, site-erected building. These types of units are frequently used on sites without significant space constraints. The building infrastructure requires an increased civil scope over modular or skid-mounted options, but provides for the integration of balance-of-plant systems. In addition, a traditional unit is marginally more shielded from the elements than a modular unit and typically has ample space to more easily provide operations / maintenance activities.

The Solar Turbines, Baker Hughes, and Siemens models noted in the modular CT section can all be installed in traditional layouts. General Electric also offers the LM2500 model that fits into the class of turbines being considered for GRH[5]. Figure 4-3 illustrates the Siemens SGT-400 combustion turbine unit.

Figure 4-3 — Siemens SGT-400 Package[6]



[4] Modular CTs are sometimes used in the industry to satisfy limited duration or finite power needs, such as extended emergencies or while larger, permanent generation facilities are being built. Their compact size allows them to be shipped to sites and relocated as needed.
[5] The GE LM2500 nominal rating is 34.4 MW based on ISO conditions and natural gas fuel – actual performance would vary with project-specific conditions and diesel fuel. This unit could be considered for GRH but would not be appropriate for WES due to its size.
[6] https://assets.siemens-energy.com/dam/4b92fab0-08bf-4ffe-8eb9-b3da0096cddd/GT-Portfolio-Brochure__HQ-pdf_Original%20file.pdf

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Similar to a modular unit, a traditional combustion turbine would be expected to operate for 30 to 40 years (or longer), based on the low number of expected annual operating hours.

4.2. RECIPROCATING INTERNAL COMBUSTION ENGINES

Similar to combustion turbines, reciprocating internal combustion engine (RICE) power plants commonly serve as back-up or peaking power support for electrical systems. A RICE is a spinning (i.e., synchronous) generator that operates using an Otto thermodynamic cycle, converting the chemical energy from fuel into mechanical energy. Similar to an automobile engine, an engine used in power generation typically has four distinct steps: intake, compression, combustion, and exhaust. During the intake step, fuel is drawn into the combustion chamber as the engine's piston moves downward. The fuel-air mixture is subsequently compressed by the piston during the compression step. Next, during the combustion step, the fuel-air mixture is ignited, increasing the pressure in the combustion chamber and pushing the piston downwards. Finally, during the exhaust step, the piston pushes the combusted mixture out of the combustion chamber. The overall cycle spins a generator, which generates electricity.

Some common manufacturers and types of units that might fit Newfoundland Power's needs include the list below. Each is dual fuel, meaning they can operate on diesel fuel.

- Wärtsilä, unit types include the 31DF and 34DF
- MAN, unit types include 35/44DF
- Caterpillar, unit types include the MaK M 46 DF

Reciprocating engines can ramp up quickly and can cycle frequently (on and off) without significant performance degradation. Given that the largest engines used for power generation are around 20 MW, a RICE power plant is frequently composed of multiple units. They can also operate efficiently at partial loads. Some characteristics of RICE units, similar to those that might be installed at GRH and WES are listed below:

- RICE units have a fairly high power density, though not as high as a comparatively sized combustion turbine. The land footprint of a RICE unit will be higher than a combustion turbine for a comparatively-sized MW capacity
- RICE units are typically much heavier than CTs of a similar MW capacity, which could make transportation and delivery to the GRH and WES sites more challenging
- Units are well suited to providing peaking generation, backup support, and ancillary services support, including increasing local fault levels and supporting voltage stability when operating
- Heat rates (fuel efficiency) are typically in the range of 8,000 to 9,000 Btu/kWh (ISO, HHV), which is approximately 15% more efficient than a combustion turbine

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- Modular and scalable design, in that additional RICE units can be added to increase power plant capacity
- Typically high plant availability given that planned maintenance can be staggered per individual RICE unit to minimize the chance of more than one unit being out of service at a single time
- RICE units experience low performance derate with higher temperature / elevation and little to no output / heat rate degradation with use
- RICE units are less commonly used as synchronous condensers; however, from a technical perspective, installation of a clutch system would allow them to be used this way. Manufacturers have designs that allow for clutch integration - for example, Wärtsilä, one of the largest engine manufacturers in the world, recently completed its first RICE project with synchronous condensing capability in 2025[7]
- Current lead times for RICE units are high – many OEMs are currently quoting 2 to 4 year lead times for RICE unit delivery

RICE would be expected to operate for 30 to 40 years (or longer) based on the low number of estimated annual operating hours. Figure 4-4 shows the Wärtsilä 34DF, which is a common dual fuel engine in the 5- to 10-MW size range, depending on the number of cylinders.

Figure 4-4 — Wärtsilä 34DF Dual Fuel Engine[8]



Wärtsilä engines can be constructed in “Modular Blocks”, which includes the engine and engine auxiliaries, and can help make construction and setup more efficient. See Figure 4-5.

[7] https://www.wartsila.com/media/news/09-12-2025-wartsila-s-first-power-plant-with-synchronous-condenser-feature-to-support-renewable-energy-integration-for-australian-mining-operation-3693751
[8] https://www.wartsila.com/energy/engine-power-plant-solutions/engine-power-plant-products/wartsila-34df-dual-fuel-engine

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Figure 4-5 — Wärtsilä "Modular Block" Concept[9]



4.3. BATTERY ENERGY STORAGE SYSTEMS

Battery Energy Storage Systems (BESS) are large-scale installations that store electrical energy so it can be used later when the grid needs it most. Unlike a power plant, a BESS does not create energy on its own; instead, it transfers energy from one time to another. A BESS resource has a finite reservoir for storing energy – typically measured in hours. The most common storage duration for BESS resources is 4 hours; however, other durations such as 2- and 8-hour are available as well. While 8-hour BESS are commercially available and increasingly deployable, they remain less prevalent than 2- to 4-hour systems. When they are selected it is typically for use cases requiring longer-duration shifting or reliability support. At the same injection capacity, an 8-hour lithium-ion battery would have approximately double the battery modules of a 4-hour lithium-ion battery.

At the heart of a BESS are the battery cells themselves, most commonly based on lithium-ion chemistries, though alternative chemistries (such as sodium-ion and flow batteries) are presently under development, but have not yet gained significant commercial adoption. Battery cells are grouped into modules, which are assembled into racks and then integrated into larger groups called strings. These components are housed in enclosures that often resemble shipping containers or prefabricated cabinets. Each enclosure typically contains the battery racks, a battery management system (BMS), and heating, ventilation, and air

[9] https://www.wartsila.com/media/news/13-06-2019-wartsila-launches-modular-solution-for-providing-ready-to-go-power-plants-3086905

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conditioning (HVAC) equipment. The BMS constantly monitors voltages, currents, and temperatures, tracks the state of charge (SoC), and ensures that the batteries operate within safe limits. The HVAC system maintains the temperature within a narrow band, since both performance and lifespan are sensitive to operating temperature. Figure 4-6 illustrates an example BESS unit.

Figure 4-6 — Example BESS Unit[10]



The power conversion system (PCS), which consists of power electronic inverters and related equipment, converts AC from the grid (for a BESS that charges from the grid) into DC suitable for charging the battery cells. Inside each cell, electrochemical reactions store this energy. Later, when the grid needs power, the process is reversed: the batteries discharge DC power, the PCS converts it back to AC at the proper voltage and frequency, and transformers step the voltage up so it can be delivered to the distribution or transmission system.

In addition to helping balance an electrical system's supply and demand via charge and discharge cycles, a BESS resource is also an excellent resource for providing ancillary services to an electrical grid. BESS excels at providing frequency regulation, where the BESS' rapid response time (often within milliseconds) allows it to quickly inject / absorb electricity to counteract system frequency deviations. Additionally, BESS units can offer voltage support by regulating reactive power to stabilize local voltage levels and BESS units can provide operating reserves (i.e., spinning reserves) to an electrical system. Given the GRH and WES sites are in fairly remote locations of the grid, S&L would recommend a BESS with grid-forming (as opposed to grid-following) inverters. A grid-forming inverter acts as a voltage source by internally generating and

[10] https://process.honeywell.com/us/en/industries/renewable-and-energy-storage-solutions/bess

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regulating its own voltage and frequency references, where traditional grid-following inverters must synchronize to an existing grid signal to operate. From an ancillary services perspective, a BESS equipped with a grid-forming inverter would be able to support the system similar to what thermal generators (CT or RICE) could support- particularly for frequency response and voltage support - though the duration of these services is limited by the energy constraints of the battery itself. A BESS unit would be expected to operate for 20 years, provided periodic augmentation[11] and maintenance is undertaken to sustain unit performance levels.

Some characteristics of BESS units that might be installed at GRH and WES are listed below:

- A BESS unit is an energy transfer resource – it shifts energy from one time to another.
- BESS resources are modular and scalable in that additional BESS modules can be added to increase plant size / duration.
- BESS resources are excellent at supporting ancillary services due to their near instantaneous response time. Some support services include frequency regulation, voltage support, operating reserves, and short-circuit strength (when equipped with grid-forming inverters). BESS paired with grid-forming inverters can improve system strength through controlled voltage and frequency support and fault current contribution, with short-circuit level a scalable design parameter that would need to be sized to meet system needs (potentially requiring a BESS resource to be designed with additional inverter capacity to meet higher short-circuit needs).
- Following discharge events, the BESS must be recharged by drawing a temporary load from the electrical system. The required charging capacity is a function of the BESS energy rating (MWh) and the desired recharge duration.
- During any extended period of time where there was an insufficient amount of electricity available to support BESS charging, a BESS resource would be limited in how much it could support the electric system. For example, if there was an extended system outage period a BESS would only be able to support the system while it was charged.
- BESS resources degrade with usage and time. To combat this and to maintain a consistent level of performance, battery plants are typically overbuilt at the start and periodically augmented (more BESS modules are added) by 5-10% every few years.
- Current lead times for BESS units are reasonable at approximately 6 to 12 months, depending on OEM.
- BESS systems can be specified with cold climate packages — including active battery preheating, insulated enclosures, and integrated thermal management systems — enabling reliable operation and full-capacity charging at very low temperatures. Cold climate configurations are commercially available from major utility-scale BESS vendors.

[11] Battery augmentation is the planned installation of additional battery modules during a BESS's operating life to compensate for expected module degradation and preserve the system's required usable energy capacity.

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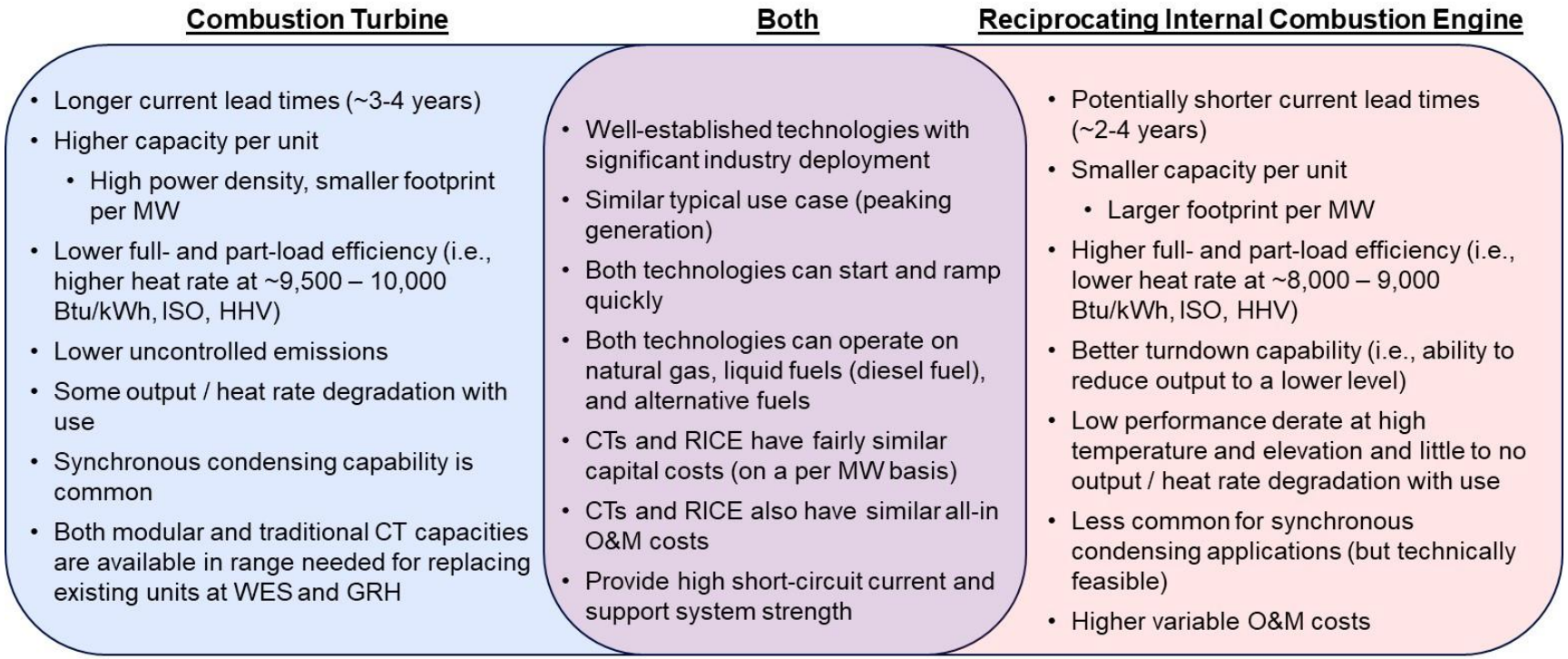
4.4. COMPARISON OF AVAILABLE TECHNOLOGIES

Combustion turbines, reciprocating engines, and battery energy storage systems are unique technologies defined by unique characteristics. Combustion turbines are high-power-density machines ideal for peaking power, ancillary services support, and synchronous condensing capability. Reciprocating engines are similar; however, they can operate at higher efficiency levels. While both CTs and RICE generate power by burning fuel, BESS functions as an energy reservoir that can provide near-instantaneous response for grid stabilization and demand management. However, BESS is limited by its storage duration, which makes it not as dependable in an emergency requiring continuous generation for long periods of time (i.e., during an extended transmission outage or supply shortfall). The following figures are provided to help detail the different and overlapping characteristics of each technology.

In addition, conceptual layouts of the different resource types at both GRH and WES are provided for illustrative / comparative purposes. The red lines illustrate the property boundaries of the sites.

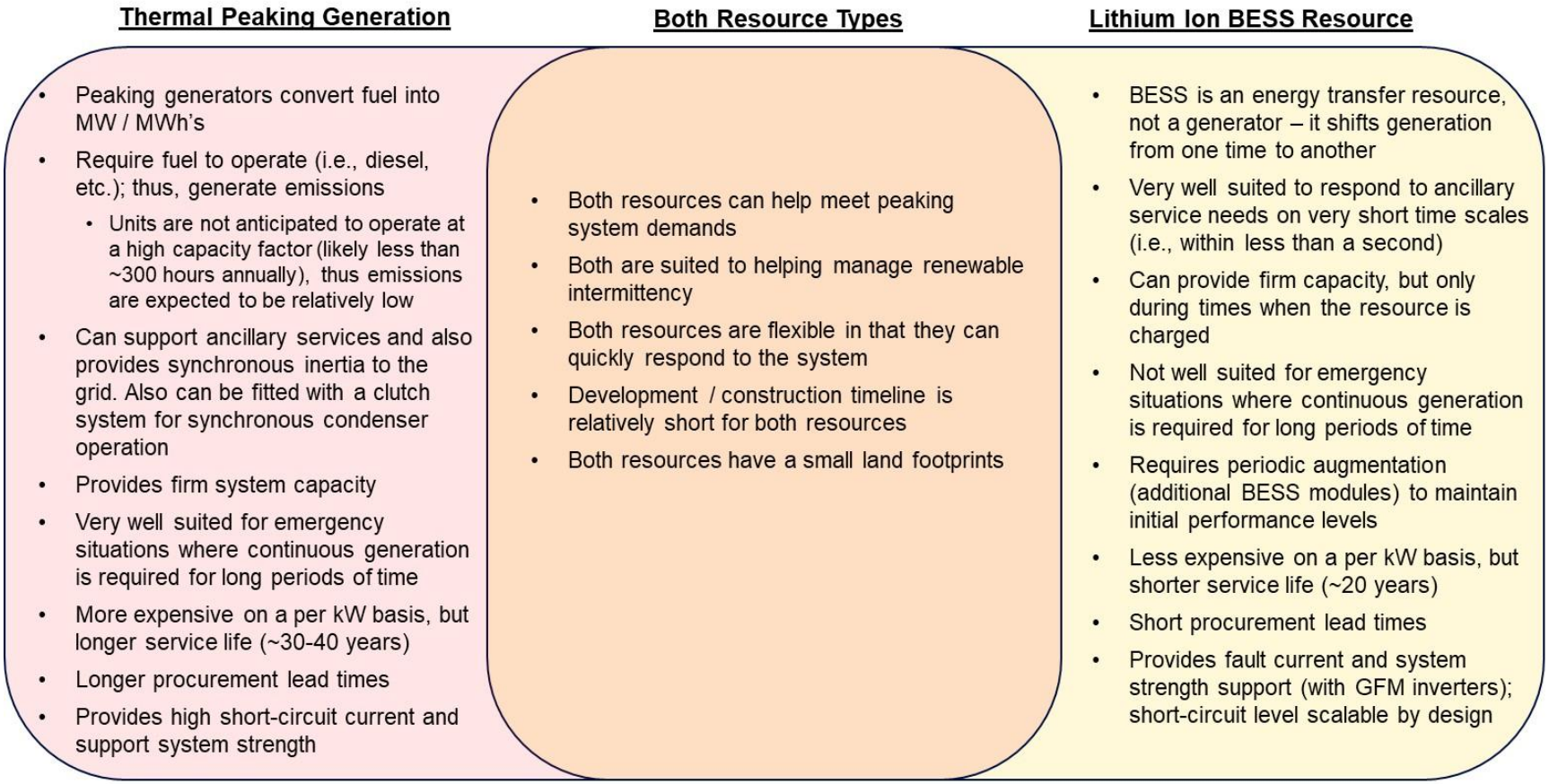
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Figure 4-7 — Qualitative Comparison of Combustion Turbines and RICE



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Figure 4-8 — Qualitative Comparison of Thermal Peaking Generation and BESS



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Figure 4-9 — Conceptual Site Layouts – Combustion Turbines

Greenhill Site

2 x Modular CTs (~30 MW)



Wesleyville Site

1 x Modular CTs (~15 MW)



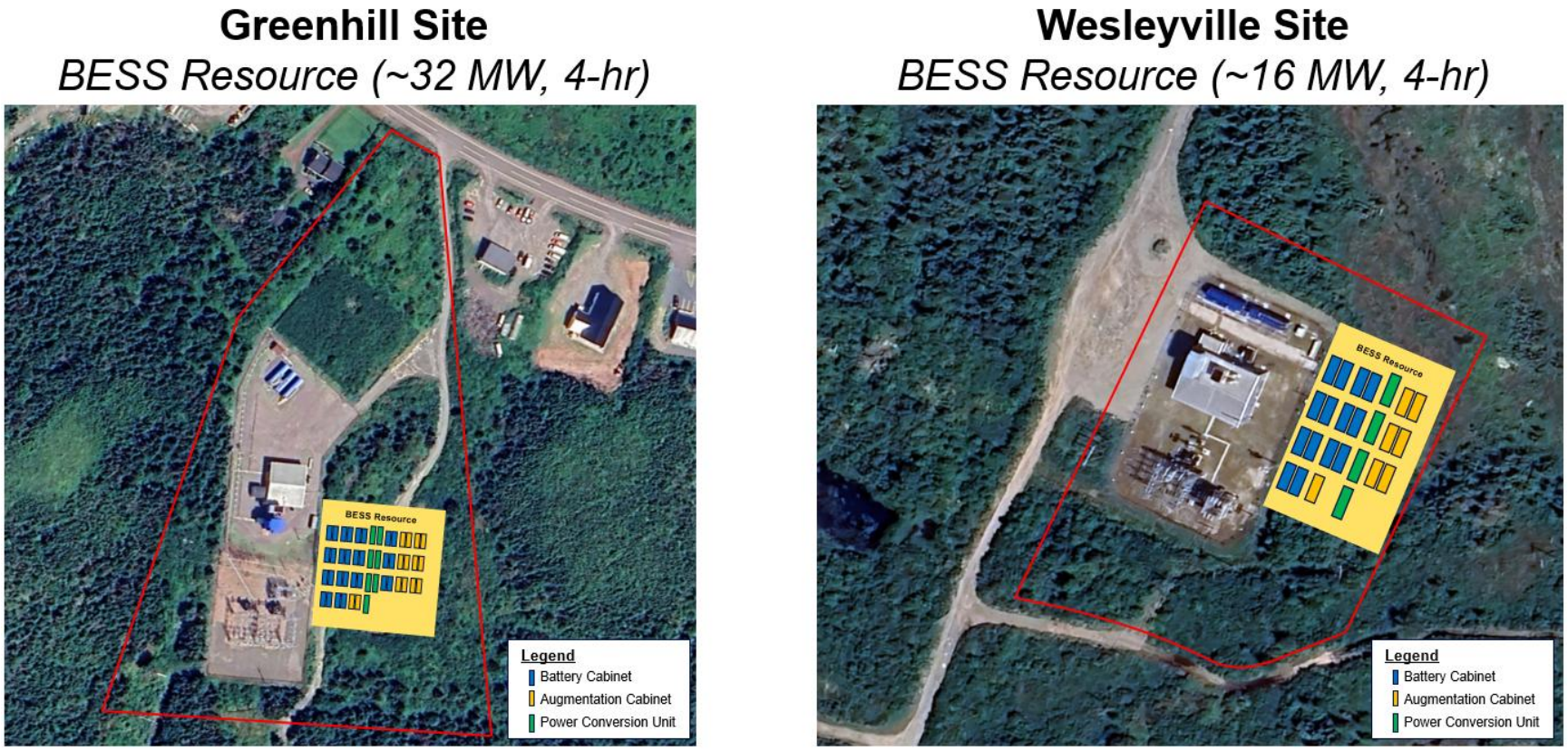
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Figure 4-10 — Conceptual Site Layouts – RICE Units



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Figure 4-11 — Conceptual Site Layouts – BESS Resources



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5. BASIS OF COST ESTIMATES

S&L developed cost estimates for the various generation replacement options considered for the Greenhill and Wesleyville sites. The table below shows the Association for the Advancement of Cost Engineering cost estimate classification system, which provides details around different cost estimate classes.

Estimate classes are based on project definition maturity level. More project definition in terms of engineering and design completed, firm procurement pricing, etc., allows for a lower cost estimate classification (at a higher expected accuracy range). The associated accuracy range of the cost estimate improves at lower classification levels (i.e. a Class 3 estimate is based on a more mature project definition than a Class 4 estimate and therefore has a higher expected accuracy range).

S&L developed Class 4/5 estimates for the different technologies considered for each site, which are appropriate given the current level of project definition (typical for feasibility studies and conceptual analysis). S&L's Class 4/5 definition is intended to capture that the estimates were developed based on a level of project maturity and detail indicative of a mid- to high-end Class 5 estimate or a low-end Class 4 estimate. S&L estimates the accuracy range of these estimates is approximately -30% to +50% of the estimated costs, at an 80% confidence interval, which is aligned with this Class 4/5 definition. Given the current level of project definition, design, and pricing certainty, S&L considers the accuracy range of the estimates presented in this section representative of the highest level of accuracy reasonably achievable at this stage.

Values for each capital cost component are based on publicly available cost estimates, S&L's internal datasets from projects of similar complexity and size, budgetary vendor pricing for major equipment, available preliminary design information, and information gathered as part of the S&L team's visits to the existing sites. The resultant values have been adjusted to 2026 CAD, assuming a conversion factor of 1.37 CAD/USD. The classification for each estimate type is shown in Table 5-1 below.

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Table 5-1 — Cost Estimate Classification Matrix

Estimate Class	Maturity Level of Project Definition Deliverables *Expressed as % of complete definition*	End Usage *Typical purpose of estimate*	Methodology *Typical estimating method*	Expected Accuracy Range *Typical variation in low and high ranges at an 80% confidence interval*
Class 5	0% to 2%	Concept screening	Capacity factored, parametric model, judgement, or analogy	Low: -20% to -50%; High: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	Low: -15% to -30%; High: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	Low: -10% to -20%; High: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	Low: -5% to -15%; High: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	Low: -3% to -10%; High: +3% to +15%

5.1. CAPITAL COST ESTIMATING

5.1.1. Overnight Capital Cost Estimate Considerations

The capital cost values provided in this report are overnight capital cost (ONC) estimates. ONC estimates fundamentally assume that the project is built “overnight” and are a common way to present costs in the energy industry as they allow for projects with different construction timelines to be compared head-to-head. When using ONC estimates, it is important to recognize that they exclude several key cost elements that are embedded in total project install costs observed in the marketplace. ONC estimates are presented in constant, nominal dollars and omit escalation, financing fees, interest during construction, and often other owner- and site-specific items such as tariffs, land acquisition, network upgrades, or offsite infrastructure. By contrast, real market prices for new generation projects account for these cost components, as well as current supply–demand conditions, any project-specific execution adders, project variations and change orders, OEM pricing strategies, and contingency allowances. Therefore, a direct, one-to-one comparison of market pricing can be misleading as a means of general technology comparison, since project-specific considerations underlying market prices are inconsistent. To go from an ONC to an all-in project cost additional items such as escalation, financing fees, and interest during construction must be considered.

The current power sector market is characterized by significant volatility in equipment and construction costs, with rapid changes over relatively short time frames. As a result, ONC estimates are intended to support planning-level technology assessments rather than firm price expectations, and the implied “validity period” of any estimate should be assumed to be short unless explicitly stated otherwise. Any comparison

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to market quotations should therefore adjust for differences in scope, cost basis year, estimate class, and financing assumptions before drawing conclusions about reasonableness or competitiveness. Additionally, the lag time between budgetary pricing estimates and quotes, and the execution of firm price agreements may include price escalation associated with increases in equipment, commodity, minerals, and labor pricing which are not reflected in the ONC estimates provided by S&L. Despite this inherent uncertainty, the estimates are considered appropriate for relative cost comparison and technology screening at this stage of project development.

Owner's cost estimates are often influenced by owner's cost assumptions; project owners often vary in their construction oversight and staffing strategies during construction. Project owners can have a less-involved approach, with few full-time personnel on site, or a more involved approach, with a substantial full-time presence on site. A project owner's strategy can significantly impact owner's costs subsequently affecting the total ONC. The owner's cost estimates included in this report are based on a less-involved (light) approach, representing a lean owner's team on-site. Newfoundland Power stated that it potentially could take a more involved Owner's approach in the event of project development, which may reduce some of the expected project costs, depending on level of involvement.

The table below details the items assumed to be included under the different ONC estimate cost categories for each case. For some cases, additional scope may be included under different categories. These items are specifically called out in notes and the overall discussion of the ONC estimates for each case. S&L notes that EPC (Indirect) and Owner's Cost & Contingency cost estimates have been determined on a percentage basis relative to direct costs. The percentages used are included in the table below and are based on typical assumptions for Class 4/5 estimates.

Table 5-2 — Overnight Capital Cost Estimate Inclusions

Cost Category	General Inclusions	Cost Estimating Methodology
Major Equipment	Key equipment for the project (CTs, RICE, BESS equipment) and any major equipment adders to be procured by Owner (synchronous condenser, exhaust stack, etc.) For CT and RICE cases, an additional 20% adder is included in the major equipment costs, which is intended to provide cushion in the cost estimate to account for the continued equipment cost escalation currently being experienced in the electricity industry, and its associated uncertainty. This is only included for the CT and RICE cases, which have been more impacted by recent market factors than BESS costs.	Cost estimates were developed based on recent indicative / budgetary vendor pricing within S&L's internal database.

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Cost Category	General Inclusions	Cost Estimating Methodology
EPC (Direct)	Direct costs included in full-wrap EPC scope,[12] including EPC-procured materials and equipment, labor, and construction equipment	Cost estimates were developed based on a combination of recent indicative / budgetary EPC pricing, S&L's internal database, and S&L's judgement based on project-specific considerations.
EPC (Indirect)	Overhead and indirect costs associated with full-wrap EPC scope, including but not limited to: • Site Overheads & Other Construction Indirects *(10-15% of EPC Direct)*: Construction management, field office expenses, material & quality control, site services, safety, temporary facilities and utilities, mobilization / demobilization, legal expenses/claims, small tools and consumables, general liability insurance, construction equipment mobilization / demobilization, freight on material. • Additional Labor Costs *(8% of EPC Direct)*: Labor supervision, show-up time, cost of overtime pay and inefficiency due to extended hours, per diem. • Project Indirect Costs *(40-50% of EPC Direct)*: EPC engineering services, EPC start-up and commissioning, start-up, spare parts, EPC General and administrative expenses (G&A), EPC fee and profit, construction management support. • EPC Contingency: Contingency on materials, equipment, labor, and indirects. ○ *20% contingency on EPC Direct, Site Overheads & Other Construction Indirects, and Additional Labor Costs.* ○ *20% contingency on Project Indirect Costs.*	Cost estimates were developed on a percentage basis. Percentage assumptions are based on indirect cost allocations observed in recent indicative / budgetary EPC pricing and market trends.

[12] A full-wrap EPC approach refers to a project delivery model in which a single contractor is responsible for designing the project, procuring equipment and materials aside from the owner-furnished major equipment, and constructing the facility. This approach is common for utility-scale generation projects.

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Cost Category	General Inclusions	Cost Estimating Methodology
Owner's Cost & Contingency	Owner-specific costs and owner's contingency, including: • Owner's Costs *(8% of direct costs)*: Project development, studies, permitting, legal, and an estimated allowance for owner's project management, engineering, and start-up / commissioning costs. • Warehouse Spares *($700k – $1MM allocation)* • Owner's Contingency: Contingency on Major Equipment and Owner's Costs ○ *20% contingency on Major Equipment* ○ *15% contingency on Owner's Costs*	Cost estimates were developed on a percentage basis. Percentage assumptions are based on S&L's experience with other projects and recent market trends.

Note: *Percentages provided for indirects & contingency are for the CT and RICE cases only. For BESS cases, EPC indirects, contingency, and owner's costs have been calculated based on different percentages of direct costs, consistent with industry expectations and typical BESS project development costs (Additional Labor – 7.5%, Overheads & Other – 10%, Project Indirects – 15%, EPC Contingency – 10%, Owner's Cost – 10% of direct costs).*

The overnight cost estimates provided by S&L in Section 6 account for the following items, as applicable:

- Existing site layout and footprint showing major components and infrastructure
- Fuel tanks, pumphouse, pumps, and supply infrastructure
- Exhaust and emissions systems
- Starting systems, including black-start generator
- Auxiliaries such as cooling and heat-rejection systems, lubrication systems, compressed gas systems
- Switchgear and electrical system.
- Protection, control, and monitoring systems
- Fire detection and suppression systems
- HVAC and ventilation
- Water supply, treatment, and wastewater handling building (note that process water use is expected to be minimal due to lack of local availability)
- Civil works – site work, drainage, access roads, foundations, structural supports, etc.

Substation-related costs are expected to be relatively comparable across the different technology options considered and would not materially impact the comparative technology evaluation. Therefore, S&L's estimates exclude the station transformer and HV-side equipment. Owner's cost estimates are inclusive of costs for preparation of tender/specification documents, assistance with analysis of bids/award, quality control (QC) services during manufacture, onsite construction assistance/inspections, commissioning and

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project sign off. Equipment estimates also include consideration for the marine environment/winter conditions the projects will be located in. Furthermore, the cost estimates consider local conditions (i.e., labor, shipping, accessibility). The estimates do not include Owner's internal costs or project financing costs or costs associated with removal of existing infrastructure. Potential environmental controls, such as the following items below, have been considered (as applicable) in the cost estimates:

- NO_x control (see Section 7)
- Waste water, oil collection
- Environmental systems monitoring
- Noise mitigation

Overnight capital cost estimates in the subsequent sections are expressed in both total dollars and dollars per kilowatt ($/kW), which are the most broadly used metrics for comparing capital costs within the energy industry. However, these metrics do not account for differences in expected service life for various technologies. As a way to incorporate expected service life into the cost estimates, overnight capital costs are also expressed in terms of $/kW-year, based on a stated service life assumption. These service-life-normalized estimates are a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset (no escalation or discount rates assumed, the metric is not indicative of net present value). This metric is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life. It is also important to note that it is difficult to predict the state of technology and associated costs in the energy industry decades from now, including the options that will be available to resource owners to extend resource service lives.

5.1.2. Schedule and Long-Lead Procurement Considerations

In recent years, utilities across North America have experienced increasing load growth, largely due to rising electricity demands from new data centers, prompting many utilities to revise their load forecasts upward. To address this demand, numerous utilities and energy companies are planning and building new power generation plants, including resources such as combined-cycle gas turbines, simple-cycle gas turbines, and reciprocating engine power plants. This surge in demand has resulted in longer lead times for combustion turbines, high voltage transformers, and other power plant equipment.

S&L has provided a development timeline estimate for each technology to give context to the distribution of capital costs over the development life of the project. With regards to each schedule estimation, S&L notes that no additional schedule, or cost, for outside the fence fuel infrastructure and transmission lines are accounted for. No explicit schedule contingency has been applied; rather, the timelines reflect current

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assumptions based on available vendor information and prevailing market conditions and may need to be updated as project definition advances, procurement strategies are refined, and supply chain conditions evolve.

The current estimated lead times for procurement of CTs, RICE, and BESS are outlined in the table below.

Table 5-3 — Long Lead Equipment Comparison

Equipment	Current Estimated Lead Time (months)
Combustion Turbines	36 – 48
RICE	24 – 48
BESS	6 – 12

5.1.3. Pricing Overview

Macroeconomic and geopolitical factors have also recently had significant impacts on power generation pricing, which is expected to continue through the coming years. Dispatchable thermal generation, such as combustion turbines and reciprocating engines have seen a significant increase in cost as a result of an increase in demand for these resources needed to power the growing number of large data centers. This increase in demand, coupled with insufficient commensurate increases in turbine / engine supply capacity by the OEMs, has driven prices higher. While there is uncertainty, recent industry trends and associated thermal generation price increases are expected to continue in the near term. As OEMs are cautious about overbuilding supply chains to meet the high demand, it is highly unlikely that costs will revert to pre-2026 levels in the next 5 years. Note that as a result, an additional market escalation factor has been applied to the Major Equipment costs to provide a reasonable allowance for continued equipment cost escalation. This additional escalation has only been applied to the CT and RICE cases, which are more exposed to global equipment market volatility than BESS technology.

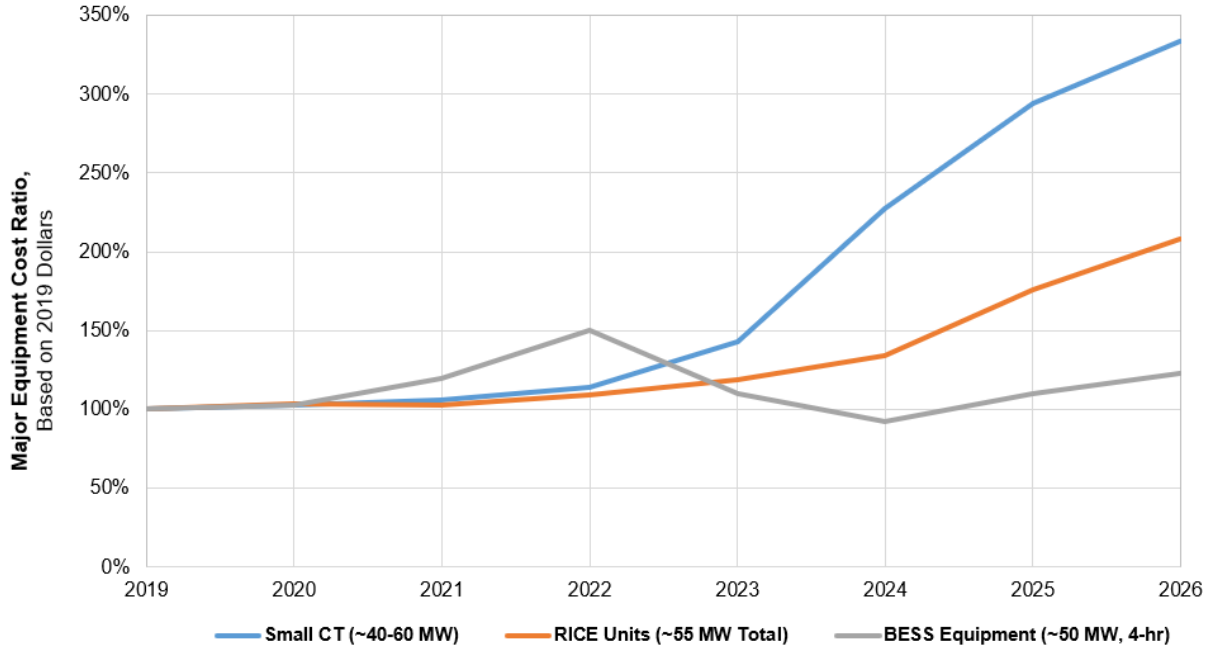
Similarly, there is high demand for EPC firms as a result of the data center-driven demand for new generation projects, in addition to higher prices of imported raw materials and components essential for constructing and maintaining power generating facilities. This increased demand grants experienced contractors greater pricing power.

Figure 5-1 below provides a high-level comparison of cost changes for smaller CTs, RICE, and BESS from 2019. Although CT, RICE, and BESS costs were all different in 2019, the 2019 cost of each technology type is levelized to 100% in the figure in order to better illustrate how much costs have changed since 2019. For each subsequent year, the costs are normalized to the 2019 cost for each respective technology (i.e.

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smaller CT prices in 2026 are approximately 3.3x more expensive than smaller CT prices in 2019). Values are based on nominal dollars.

Figure 5-1 — Comparison of Small CT, RICE, and BESS Pricing Change Versus 2019



Source: S&L internal project data

Cost estimates of this type are informed by project and market data available at the time of preparation and are therefore inherently retrospective. This report was drafted in the first quarter of 2026. As previously noted, capital costs for new generation facilities are influenced by numerous technical, commercial, and regulatory factors.

5.2. OPERATING AND MAINTENANCE COST ESTIMATING

Once a plant enters commercial operation, the plant owners incur ongoing costs for the operation and maintenance (O&M) of the facility. These costs are categorized into fixed O&M costs which are incurred annually independent of the facility dispatch, and variable O&M costs which are incurred based on the hours of operation. O&M costs presented in this report do not include the costs for fuel or fuel procurement activities. Given the low expected capacity factor for the CT and RICE cases, S&L has assumed a self-performed O&M approach will be utilized rather than a long-term service agreement (LTSA), except for planned maintenance overhauls. For the BESS cases, S&L has assumed utilization of an LTSA O&M approach, from the OEM.

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Fixed and Variable O&M costs provided are Year 1 estimates in 2026 CAD. Major maintenance, minor maintenance, and lifetime BESS augmentation costs are provided in unescalated 2026 CAD. To assess the cost of a maintenance event or BESS augmentation costs in a given year, an escalation factor, and battery pricing forecast, would need to be applied to the provided values. Table 5-4 below outlines general inclusions and discussion for the O&M cost estimates provided.

Table 5-4 — O&M Cost Estimate Inclusions

Cost Category	General Inclusions
Fixed O&M ***($/kW-year, 2026 CAD)***	Includes routine labor, materials and contract services, and administrative and general expenses: • Routine labor: Includes the regular maintenance of the equipment as recommended by the equipment manufacturers (pumps, compressors, transformers, instruments, controls, and valves). Typically, routine maintenance does not require a plant outage. • Materials and contract services: Include the materials associated with the routine labor as well as contracted services such as those covered under a long-term service agreement. ○ RICE and CT cases assume O&M to be self-performed aside from planned minor/major maintenance, and therefore Fixed O&M estimates for those cases do not include LTSA costs such as fixed annual payments, engineering and tech support, remote monitoring, contract management etc. ○ BESS cases assume LTSA costs are included in Fixed O&M estimates. • General and administrative expenses (G&A): include operation expenses, comprised of management salaries, and office utilities. Excludes items such as insurance, taxes and fees, transmission expenses, back-end G&A and corporate costs (off-site administrative expenses), any land costs, site security, grounds maintenance and landscaping beyond operational needs.
Variable O&M ***($/MWh, CAD)***	Includes costs that vary based on the amount of electrical generation at the power plant (chemicals, lubricants, water, waste, wastewater discharge, calibration gas, etc.). Fuel costs are excluded from Variable O&M estimates for all cases. Typical LTSA costs associated with number of starts and/or fire hours of the engines/turbines are excluded from the O&M estimate.
Major & Minor Maintenance ***(2026 CAD, unescalated)***	Includes major and minor overhauls carried out by the equipment OEM at defined intervals during the plant's operating life: • CT cases: Major maintenance overhauls are typically expected to occur every 30,000 operating hours. Given the low operating hours expected for the sites, the CT OEM may require overhauls on a starts / inspections / number of operating years basis, instead. • RICE cases: Major maintenance overhauls are expected to occur every 18,000 operating hours. Minor maintenance would be expected to occur every 6,000 after the first major maintenance event. Given the low operating hours expected for the sites, the RICE OEM may require overhauls on a starts / inspections / number of operating years basis, instead.
Lifetime BESS Augmentation ***(2026 CAD, unescalated)***	Includes the cost to periodically install additional battery modules to account for degradation and maintain the plant's desired capacity. Estimates provided assume 7.5% capacity augmentation every 3 years over a 20-year useful life. Six total augmentations are expected over the lifetime of the BESS.

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6. COST ESTIMATES

6.1. MODULAR COMBUSTION TURBINES

This case is modeled on a modular combustion turbine of approximately 15 MW, representative of current market offerings. The cost estimate for Wesleyville is based on a single modular unit operating in a simple-cycle configuration, while the cost estimate for Greenhill is based on two modular units operating in a simple-cycle configuration. Both cases are based on the use of ultra-low sulfur diesel (ULSD) fuel. The CT is equipped with dry low emissions (DLE) combustion technology, which reduces the CT's NO_X emissions without requiring water or steam injection. No selective catalytic reduction (SCR) unit is assumed, as the DLE technology is expected to reduce NO_X emissions sufficiently (see Section 7 for additional discussion). Output power voltage is stepped up for transmission to the external grid through an onsite switchyard. General parameters for this case are outlined in the table below.

Table 6-1 — Modular CT Parameters

Parameter	Units	Wesleyville	Greenhill
Reference Technology	–	1 x Modular CT	2 x Modular CTs
Total Capacity[1] (Approximate)	MW	15.2	30.4
Fuel Type	–	ULSD	ULSD

[1]Capacity values provided are estimated based on ISO ratings assuming operation using ULSD.

6.1.1. Overnight Capital Cost Estimate

Table 6-2 summarizes the cost components for this case. S&L notes that this estimate is based on an EPC contracting approach. Costs are in 2026 CAD.

S&L considered the ability to leverage existing infrastructure at the site and account for any applicable savings. Based on S&L's site visit, it was determined that only a limited amount of existing site infrastructure could potentially be reused.

In addition to EPC contract costs, the capital cost estimate includes owner's costs comprising project development, studies, owner's engineering, permitting, legal, owner's contingency, and an estimated allowance for owner's project management and start-up and commissioning costs. Owner's costs do not include the purchase of land or network upgrades. The estimated owner's cost is based on a percentage of the major equipment and EPC costs outlined in the estimate below. The estimate is presented as an

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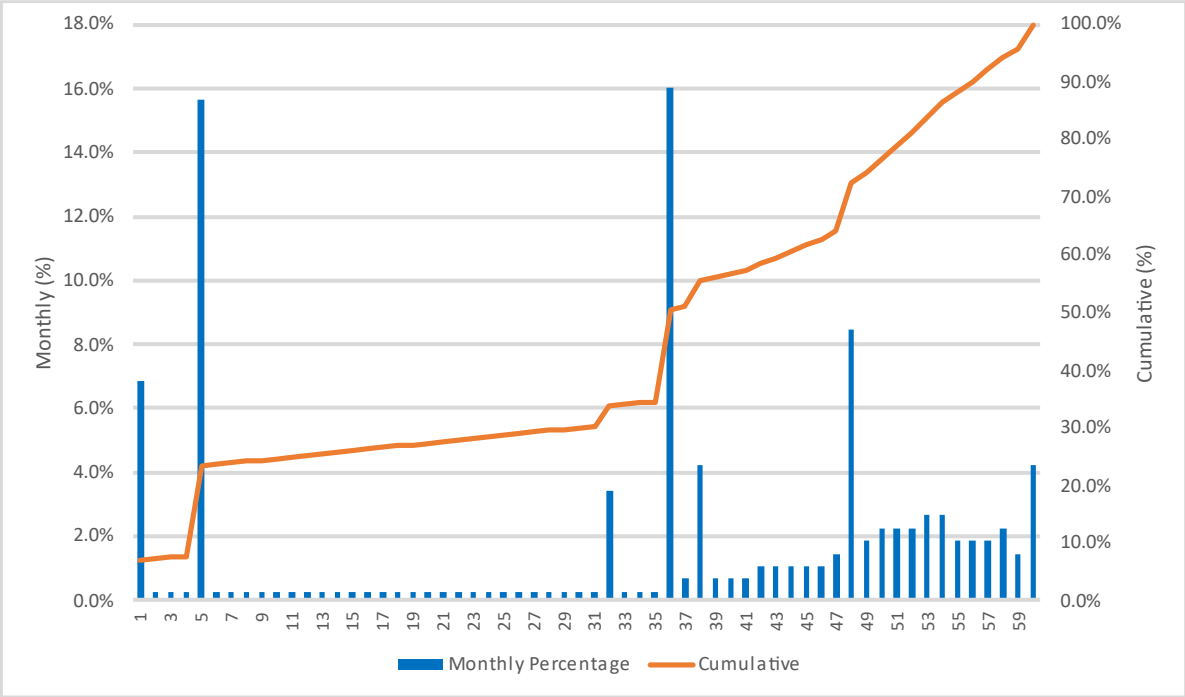
overnight capital cost in 2026 dollars and thus excludes escalation, financing costs, and interest during construction. A representative schedule for such a project is outlined in Figure 6-1.

Table 6-2 — Modular CT Capital Cost Estimate

Cost Category	Wesleyville		Greenhill	
	Cost (CAD)	Cost ($/kW)	Cost (CAD)	Cost ($/kW)
Major Equipment[1]	32,200,000	2,118	63,000,000	2,072
EPC (Direct)[2]	15,900,000	1,046	23,200,000	763
EPC (Indirect)	17,200,000	1,132	20,800,000	684
Owner's Costs & Contingency	10,900,000	717	19,200,000	632
Total Overnight Cost (ONC)	**76,200,000**	**5,013**	**126,200,000**	**4,151**
Total Overnight Cost ($/kW-year)[3]	**143**		**119**	
Capital Cost Notes				
1. Inclusive of adders for modular CT configuration, auxiliary equipment (fuel oil centrifuge, black start generator, exhaust stack, etc.), synchronous condenser, freight, and OEM engineering & logistics support.				
2. Includes savings in EPC scope due to simplified installation of modular units compared to traditional CT installations.				
3. The $/kW-year calculation is based on a service life of 35 years. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.				

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Figure 6-1 — Modular CT, Post-FID Representative Development Cash Flow



6.1.2. Operations & Maintenance Cost Estimate

Fixed and variable O&M costs are based on Year 1, 2026 CAD. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. Property taxes and insurance are not included. Variable O&M costs include consumable commodities, such as lubricants, chemicals, and water. Fuel costs are not included. S&L notes that for O&M, Newfoundland Power runs a lean O&M operation given the low operating hours of their units, allowing labor resources to be shared across sites, thereby requiring less full-time equivalent employees than similar plants owned by other operators. S&L's estimate accounts for this shared staffing under fixed O&M, which is typical for O&M categorization, to allow for comparison across technologies. However, given the operating profiles expected for these sites, Newfoundland Power allocated some of the staffing costs as a variable expense, which S&L considers a reasonable approach based on the operating profile of the plants. S&L also notes that the fixed O&M estimate outlined below includes costs for repairs/upgrades that could potentially be capitalized.

Also included are the total expected costs for planned maintenance events for the CT over the maintenance cycle. CTs generally have two criteria for scheduling overhauls, (i) number of equivalent starts and (ii) number of equivalent operating hours (EOH). Major maintenance overhauls are typically expected to occur every 30,000 operating hours. Given the low operating hours expected for the sites, the OEM may recommend conducting overhauls on a starts-based cadence, or number of operating years, instead.

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Planned maintenance cost estimates are provided in unescalated 2026 CAD. Escalation would be required to scale the estimate to the year in which the maintenance event would occur.

An additional advantage of CTs is that some OEMs offer turbine exchange programs for overhauls and major maintenance where the OEM provides an exchange turbine of similar configuration while the overhaul is being done, reducing the outage time of major overhauls.

Table 6-3 — Modular CT Non-Fuel O&M

Cost Category	Units	Wesleyville	Greenhill
Fixed O&M[1]	$/kW-year	26.50	21.50
Variable O&M[2]	$/MWh	0.50	0.50
Major Maintenance Overhaul[3]	CAD	7,500,000	15,000,000
O&M Cost Notes			
1. Includes routine maintenance labor, materials and contract services, and G&A. Assumes O&M will be self-performed aside from minor / major maintenance overhauls. S&L has estimated lower FTEs at each site based on Newfoundland Power's operating approach which facilitates sharing of labor resources across multiple sites. Excludes non-technical O&M costs such as insurance, taxes and fees, transmission expenses, back-end G&A and corporate costs (off-site administrative expenses), any land costs, site security, grounds maintenance and landscaping beyond operational needs.			
2. Includes costs that vary based on the amount of electrical generation at the power plant (chemicals, lubricants, water, waste, wastewater discharge, calibration gas, etc.). Does not include fuel costs.			
3. Major overhaul costs have not been incorporated in fixed or variable O&M estimates since this threshold (approximately 30,000 hours for the first major maintenance interval) is not expected to be reached during the typical 30-40-year useful life with the plants' operating profiles, depending on the agreed upon contracting structure with the OEM.			

6.2. TRADITIONAL COMBUSTION TURBINES

This case is modeled on a traditional CT of approximately 15 MW, representative of current market offerings. The cost estimate for Wesleyville is based on a single unit operating in a simple-cycle configuration, while the cost estimate for Greenhill is based on two units operating in a simple-cycle configuration. Both cases are based on the use of ULSD fuel. The CT is equipped with DLE combustion technology, which reduces the CT's NO_X emissions without requiring water or steam injection. Similar to the modular CT case, no SCR unit is assumed (see Section 7). Output power voltage is stepped up for transmission to the external grid through an onsite switchyard. General parameters for this case are outlined in the table below.

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Table 6-4 — Traditional CT Parameters

Parameter	Units	Wesleyville	Greenhill
Reference Technology	–	1 x Traditional CT	2 x Traditional CTs
Total Capacity[1] (Approximate)	MW	15.2	30.4
Fuel Type	–	ULSD	ULSD

[1]Capacity values provided are estimated based on ISO ratings assuming operation using ULSD.

6.2.1. Overnight Capital Cost Estimate

The following table summarizes the cost components for this case. S&L notes that this estimate is based on an EPC contracting approach. Costs are in 2026 CAD. S&L considered the ability to leverage existing infrastructure at the site and account for any applicable savings. Based on S&L's site visit, it was determined that only a limited amount of existing site infrastructure could potentially be reused.

In addition to EPC contract costs, the capital cost estimate includes owner's costs comprising project development, studies, owner's engineering, permitting, legal, owner's contingency, and an estimated allowance for owner's project management and start-up and commissioning costs. Owner's costs do not include the purchase of land or network upgrades. The estimated value for owner's cost is based on a percentage of the major equipment, and EPC costs highlighted in the estimate below. The estimate is presented as an overnight capital cost in 2026 dollars and thus excludes escalation, financing costs, and interest during construction. An estimated development timeline for such a project is outlined in Figure 6-2.

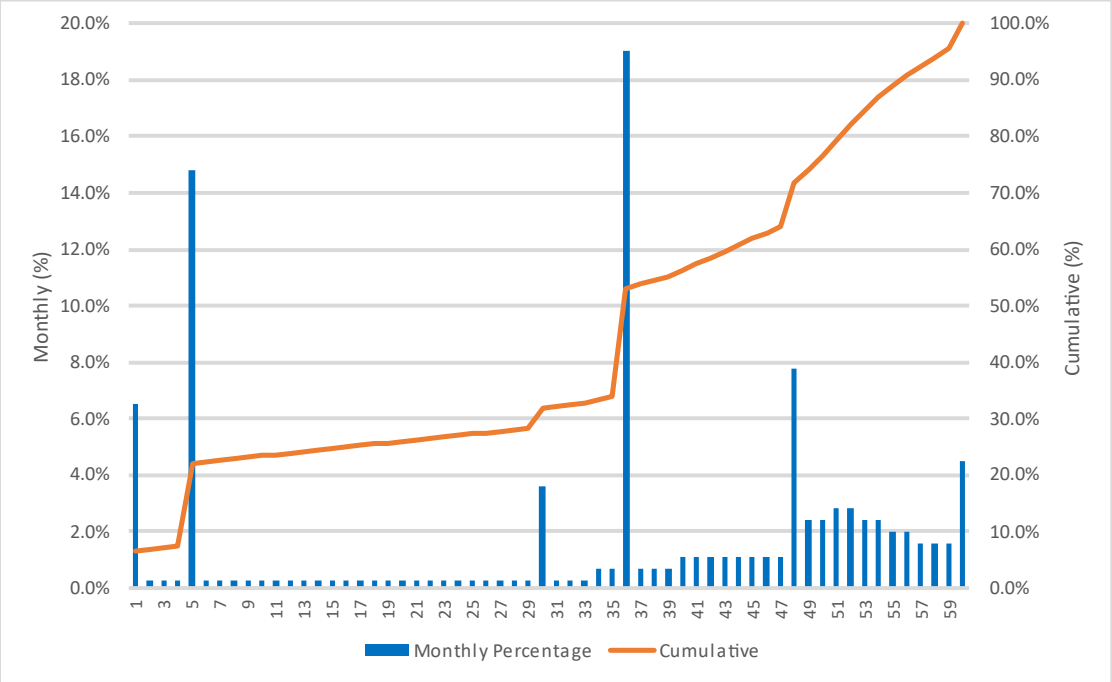
Table 6-5 — Traditional CT Capital Cost Estimate

Cost Category	Wesleyville		Greenhill	
	Cost (CAD)	Cost ($/kW)	Cost (CAD)	Cost ($/kW)
Major Equipment[1]	31,200,000	2,053	61,000,000	2,007
EPC (Direct)	16,900,000	1,112	25,800,000	849
EPC (Indirect)	18,300,000	1,204	23,200,000	763
Owner's Costs & Contingency	10,800,000	711	19,400,000	638
Total Overnight Cost (ONC)	**77,200,000**	**5,079**	**129,400,000**	**4,257**
Total Overnight Cost ($/kW-year)[2]	**145**		**122**	
Capital Cost Notes				
1. Inclusive of adders for auxiliary equipment (fuel oil centrifuge, black start generator, exhaust stack, etc.), synchronous condenser, freight, and OEM engineering & logistics support.				

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Cost Category	Wesleyville		Greenhill	
	Cost (CAD)	Cost ($/kW)	Cost (CAD)	Cost ($/kW)
2. The $/kW-year calculation is based on a service life of 35 years. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.				

Figure 6-2 — Traditional CT, Post-FID Representative Development Cash Flow



6.2.2. Operations & Maintenance Cost Estimate

Fixed and variable O&M costs are based on Year 1, 2026 CAD. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. Property taxes and insurance are not included. Variable O&M costs include consumable commodities, such as lubricants, chemicals, and water. Fuel costs are not included. S&L notes that for O&M, Newfoundland Power runs a lean O&M operation given the low operating hours of their units, allowing labor resources to be shared across sites, thereby requiring less full-time equivalent employees than similar plants owned by other operators. S&L's estimate accounts for this shared staffing under fixed O&M, which is typical for O&M categorization, to allow for comparison across technologies. However, given the operating profiles expected for these sites, Newfoundland Power allocated some of the staffing costs as a variable expense, which S&L considers a reasonable approach based on the operating profile of the plants. S&L also notes that the fixed O&M estimate outlined below includes costs for repairs/upgrades that could potentially be capitalized.

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Also included are the total expected costs for planned maintenance events for the CT over the maintenance cycle. CTs generally have two criteria to schedule overhauls, (i) number of equivalent starts and (ii) number of equivalent operating hours (EOH). Major maintenance overhauls are typically expected to occur approximately every 30,000 operating hours. Given the low operating hours expected for the sites, the OEM may recommend conducting overhauls on a starts-based cadence, or number of operating years, instead. Planned maintenance cost estimates are provided in unescalated 2026 CAD. Escalation would be required to scale the estimate to the year in which the maintenance event would occur.

An additional advantage of CTs is that some OEMs offer a turbine exchange programs for overhauls and major maintenance where the OEM provides an exchange turbine of similar configuration while the overhaul is being done, reducing the outage time of major overhauls.

Table 6-6 — Traditional CT Non-Fuel O&M

Cost Category	Units	Wesleyville	Greenhill
Fixed O&M[1]	$/kW-year	26.50	21.50
Variable O&M[2]	$/MWh	0.50	0.50
Major Maintenance Overhaul[3]	CAD	7,500,000	15,000,000
O&M Cost Notes			
1. Includes routine labor, materials and contract services, and G&A. Assumes O&M will be self-performed aside from minor / major maintenance overhauls. S&L has estimated lower FTEs at each site based on Newfoundland Power's operating approach which facilitates sharing of labor resources across multiple sites. Excludes non-technical O&M costs such as insurance, taxes and fees, transmission expenses, back-end G&A and corporate costs (off-site administrative expenses), any land costs, site security, grounds maintenance and landscaping beyond operational needs.			
2. Includes costs that vary based on the amount of electrical generation at the power plant (chemicals, lubricants, water, waste, wastewater discharge, calibration gas, etc.). Does not include fuel costs.			
3. Major overhaul costs have not been incorporated in fixed or variable O&M estimates since this threshold (approximately 30,000 hours for the first major maintenance interval) is not expected to be reached during the typical 30-40-year useful life with the plants' operating profiles.			

6.3. RECIPROCATING INTERNAL COMBUSTION ENGINES

This case is modeled on reciprocating internal combustion engines of approximately 9 MW, representative of current market offerings. The cost estimate for Wesleyville is based on two units, while the cost estimate for Greenhill is based on three units. Both cases are based on the use of ULSD fuel. Major equipment cost estimates include an SCR system to reduce NO_X emissions and CO catalysts for further emissions reduction, since the engines are not assumed to be equipped with alternative NO_X emissions reduction technologies (i.e. the DLE technology assumed for the CT cases). General parameters for this case are outlined in the following table.

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Table 6-7 — RICE Parameters

Parameter	Units	Wesleyville	Greenhill
Reference Technology	–	2 x ~9 MW RICE units	3 x ~9 MW RICE units
Total Capacity (Approximate)	MW	18.6	27.9
Fuel Type	–	ULSD	ULSD

6.3.1. Overnight Capital Cost Estimate

The following table summarizes the cost components for this case. S&L notes that this estimate is based on an EPC contracting approach. Costs are in 2026 CAD. S&L considered the ability to leverage existing infrastructure at the site and account for any applicable savings. Based on S&L's site visit, it was determined that only a limited amount of existing site infrastructure could potentially be reused.

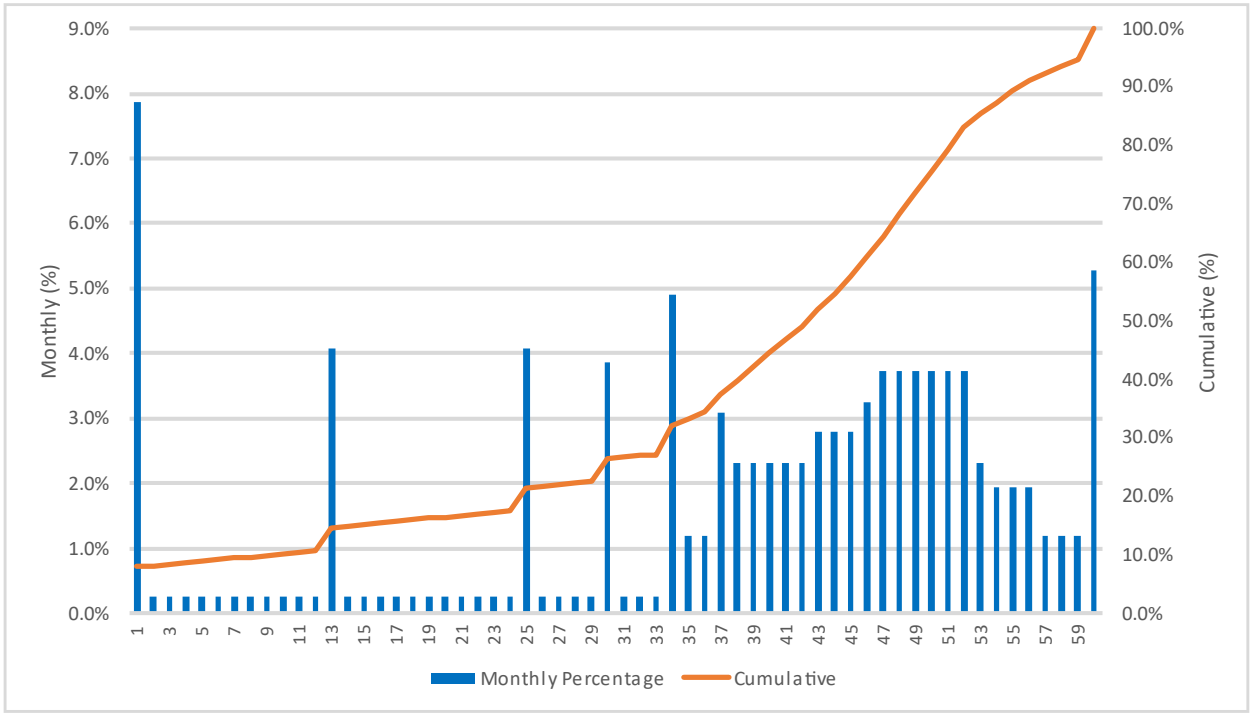
In addition to EPC contract costs, the capital cost estimate includes owner's costs comprising project development, studies, owner's engineering, permitting, legal, owner's contingency, and an estimated allowance for owner's project management and start-up and commissioning costs. Owner's costs do not include the purchase of land or network upgrades. The estimated value for owner's cost is based on a percentage of the major equipment, and EPC costs highlighted in the estimate below. The estimate is presented as an overnight capital cost in 2026 dollars and thus excludes escalation, financing costs, and interest during construction. An estimated development timeline for such a project is outlined in Figure 6-3.

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Table 6-8 — RICE Capital Cost Estimate

Cost Category	Wesleyville		Greenhill	
	Cost (CAD)	Cost ($/kW)	Cost (CAD)	Cost ($/kW)
Major Equipment[1]	40,200,000	2,161	58,600,000	2,100
EPC (Direct)	23,100,000	1,242	30,800,000	1,104
EPC (Indirect)	24,900,000	1,339	27,700,000	993
Owner's Costs & Contingency	14,200,000	763	19,700,000	706
Total Overnight Cost (ONC)	**102,400,000**	**5,505**	**136,800,000**	**4,903**
Total Overnight Cost ($/kW-year)[2]	**157**		**140**	
Capital Cost Notes				
1. Inclusive of adders for SCR system, auxiliary equipment (fuel oil system, exhaust stack, etc.), synchronous condenser, freight, and OEM engineering & logistics support.				
2. The $/kW-year calculation is based on a service life of 35 years. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.				

Figure 6-3 — RICE, Post-FID Representative Development Cash Flow



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6.3.2. Operations & Maintenance Cost Estimate

O&M costs are based on Year 1, 2026 CAD. Fixed O&M costs include staff and administrative costs, supplies, and minor routine maintenance. Property taxes and insurance are not included. Variable O&M costs include consumable commodities, such as lubricants, chemicals, and water. Fuel costs are not included. S&L notes that for O&M, Newfoundland Power runs a lean O&M operation given the low operating hours of their units, allowing labor resources to be shared across sites, thereby requiring less full-time equivalent employees than similar plants owned by other operators. S&L's estimate accounts for this shared staffing under fixed O&M, which is typical for O&M categorization, to allow for comparison across technologies. However, given the operating profiles expected for these sites, Newfoundland Power allocated some of the staffing costs as a variable expense, which S&L considers a reasonable approach based on the operating profile of the plants. S&L also notes that the fixed O&M estimate outlined below includes costs for repairs/upgrades that could potentially be capitalized.

Also included are the total expected costs for planned maintenance events for the engine over the maintenance cycle. Planned maintenance overhauls are typically conducted on an hours-based cycle as opposed to a starts-based cycle for RICE. Major overhauls are estimated to be performed every 18,000 engine hours. Minor overhauls are expected every 6,000 hours after the first major maintenance event. S&L notes that the RICE OEM may require more frequent maintenance events depending on expected operational profile.

Table 6-9 — RICE Non-Fuel O&M

Cost Category	Units	Wesleyville	Greenhill
Fixed O&M[1]	$/kW-year	23.00	23.00
Variable O&M[2]	$/MWh	5.50	5.50
Minor Maintenance Overhaul[3]	CAD	1,500,000	2,000,000
Major Maintenance Overhaul[4]	CAD	4,000,000	5,000,000
O&M Cost Notes			
1. Includes routine labor, materials and contract services, and G&A. Assumes O&M will be self-performed aside from minor / major maintenance overhauls. S&L has estimated lower FTEs at each site based on Newfoundland Power's operating approach which facilitates sharing of labor resources across multiple sites. Excludes non-technical O&M costs such as insurance, taxes and fees, transmission expenses, back-end G&A and corporate costs (off-site administrative expenses), any land costs, site security, grounds maintenance and landscaping beyond operational needs.			
2. Includes costs that vary based on the amount of electrical generation at the power plant (chemicals, lubricants, water, waste, wastewater discharge, calibration gas, etc.). Does not include fuel costs.			

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Cost Category	Units	Wesleyville	Greenhill
3. Minor overhaul costs have not been incorporated in fixed or variable O&M estimates since this threshold (approximately 24,000 hours for the first minor maintenance interval) is not expected to be reached during the typical 30–40-year useful life with the plants' operating profiles.			
4. Major overhaul costs have not been incorporated in fixed or variable O&M estimates since this threshold (approximately 18,000 hours for the first major maintenance interval) is not expected to be reached during the typical 30-40-year useful life with the plants' operating profiles.			

6.4. BATTERY ENERGY STORAGE SYSTEMS

This case is modeled on a utility-scale, lithium-ion, 4-hour battery energy storage system (BESS). A 4-hour system is assumed because it is the most widely utilized BESS configuration in the market. S&L notes that a BESS configured for a longer storage and discharge duration, such as 8-12 hours, may be more appropriate for Newfoundland Power's applications and use cases. Developing a BESS plant at the same power rating but higher storage duration would result in an approximately linear increase in cost (e.g., an 8-hour BESS would be approximately 1.7 – 2.0x the cost of a 4-hour storage duration BESS of the same power rating).

The cost estimate for Wesleyville is based on a 16 MW / 64 MWh BESS, while the cost estimate for Greenhill is based on a 32 MW / 128 MWh BESS. The containerized BESS comprises modular, factory-integrated battery storage containers that house the batteries and supporting systems (for example, battery management system, electrical protections, thermal management system, fire protection, etc.). This case also assumes the use of grid-forming inverters, which have become increasingly popular for recent BESS developments as they can help a BESS provide more robust grid support services. The cost estimates assume that the BESS will charge from the grid, and therefore do not include costs associated with additional generation infrastructure.

Approximately 1.5% of the battery capacity is assumed to degrade each year, on average, and require augmentation by the addition of new batteries. Battery containers are grouped together and connected with an associated inverter-transformer skid (power conversion system or PCS). The PCS houses the inverters, medium voltage transformers, and associated fuses and breakers. General parameters for this case are outlined in the table below.

Table 6-10 — BESS Parameters

Parameter	Units	Wesleyville	Greenhill
Reference Technology	-	Li-Ion BESS	Li-Ion BESS
Total Capacity (Approximate)	MW / MWh	16 / 64	32 / 128

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6.4.1. Overnight Capital Cost Estimate

The table below summarizes the cost components for this case. S&L notes that this estimate is based on an EPC contracting approach. Costs are in 2026 CAD.

S&L considered the ability to leverage existing infrastructure at the site. Based on S&L's site visit, it was determined that only a limited amount of existing site infrastructure could potentially be reused for the project. Some minor cost savings have been included in the estimates to account for reduced costs for civil and architectural scopes. The cost assumes an approximate 3-year overbuild of the BESS to maintain nameplate energy capacity through the first 3 years of operation.

In addition to EPC contract costs, the capital cost estimate includes owner's costs comprising project development, studies, owner's engineering, permitting, legal, owner's contingency, and an estimated allowance for owner's project management and start-up and commissioning costs. Owner's costs do not include the purchase of land or network upgrades. The estimated value for owner's cost is based on a percentage of the major equipment, and EPC costs highlighted in the estimate below. The estimate is presented as an overnight capital cost in 2026 dollars and thus excludes escalation, financing costs, and interest during construction. An estimated development timeline for such a project is outlined in Figure 6-4.

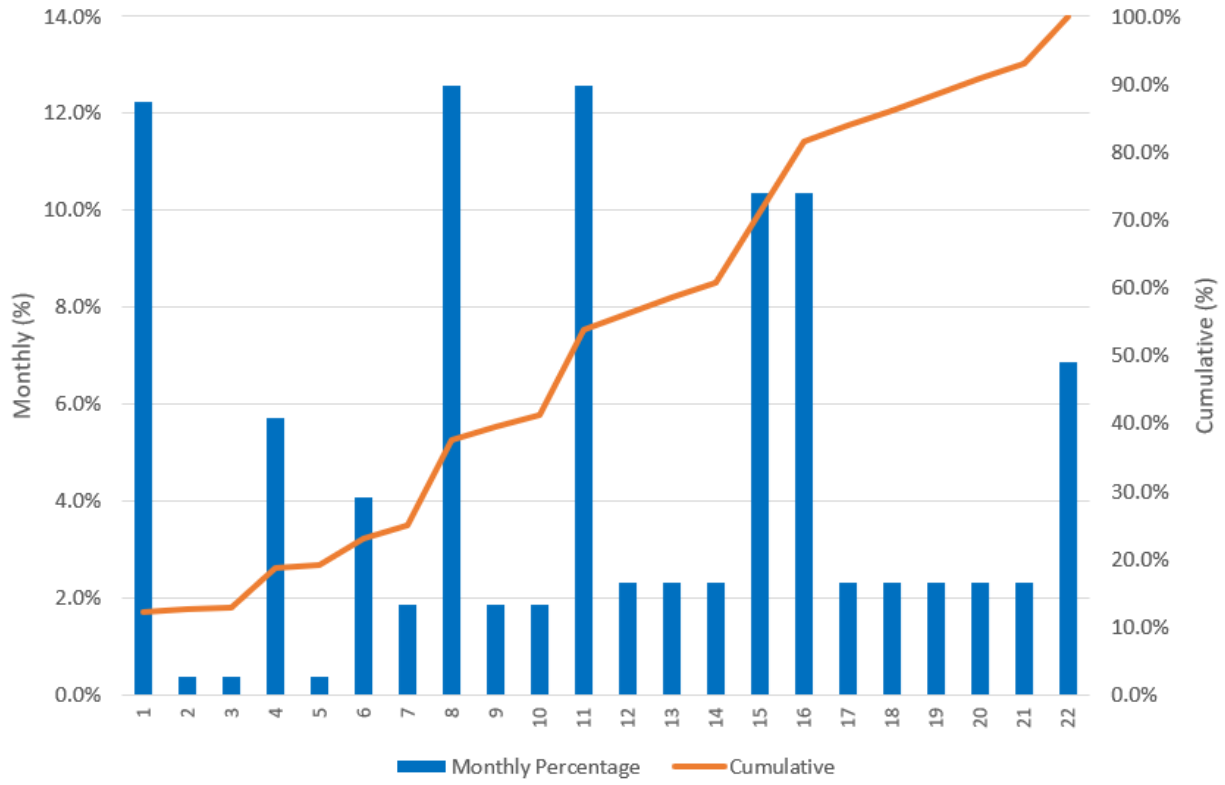
Table 6-11 — BESS Capital Cost Estimate[1]

Cost Category	Wesleyville		Greenhill	
	Cost (CAD)	Cost ($/kW)	Cost (CAD)	Cost ($/kW)
Major Equipment[2]	24,100,000	1,506	46,500,000	1,453
EPC (Direct)[3]	14,900,000	931	22,600,000	706
EPC (Indirect)	6,300,000	394	9,700,000	303
Owner's Costs & Contingency	4,500,000	281	7,900,000	247
Total Overnight Cost (ONC)	**49,800,000**	**3,113**	**86,700,000**	**2,709**
Total Overnight Cost ($/kW-year)[4]	**156**		**135**	
Capital Cost Notes				
1. This estimate is based on a 4-hour BESS as it is the most widely utilized configuration in the market. An 8-12 hour BESS may be more appropriate for this use case. Higher storage duration results in an approximately linear increase in cost (e.g., an 8-hour BESS would be approximately 1.7 – 2.0x the cost of a 4-hour BESS).				
2. Includes initial overbuild to account for first 3 years of battery degradation.				
3. Includes procurement of grid-forming BESS inverters.				

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Cost Category	Wesleyville	Greenhill
4. The $/kW-year calculation is based on a service life of 20 years. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.		

Figure 6-4 — BESS, Post-FID Representative Development Cash Flow



6.4.2. Operations & Maintenance Cost Estimate

O&M costs are based on Year 1, 2026 CAD. The O&M cost estimate considers the ongoing O&M cost through the life of a BESS project. The service life of a BESS depends on how it is used. This case assumes a 20-year useful life of the BESS, with 365 cycles annually. This assumption is based on a load-shifting use case, where the BESS charges from the grid during the day and discharges in the evening. S&L considers this to be a realistic use case for a BESS installation for the purpose of estimating O&M costs.

Capacity degradation of lithium-ion batteries is an inherent performance characteristic of lithium-ion battery technology. OEM battery performance guarantees vary, with an approximate value of 1.5% annual capacity degradation (average over the lifetime of the battery) associated with one cycle per day operations. If batteries are not cycled every day, this degradation would likely be slightly lower, but still averaging greater

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than 1% annually. Note that BESS degradation and life is driven primarily by two mechanisms: calendar aging (occurring with time regardless of use) and cycle aging (driven by charge/discharge activity, depth of discharge, etc.). BESS degradation is non-linear—it is typically faster at the start of the project (approximately 2% to 3% annually in the first two to three years), then stabilizes through mid-life (sub 2% annually), and can accelerate again near end of life.

Many BESS projects engage a third-party contractor to conduct regular O&M activities. This cost estimate considers the cost of such contracted services, which include remote monitoring of the system, periodic onsite inspection of equipment conditions and cable connections, replacement of regular consumables (air filters, coolant, etc.), and grounds maintenance. The fixed O&M cost estimate assumes execution of long-term service agreement (LTSA) which includes extended warranty and capacity guarantees.

The estimated lifetime augmentation required to be performed periodically to maintain the nameplate capacity of the BESS throughout the useful life is based on an assumed 7.5% capacity augmentation every 3 years of operation, which is typical for a BESS to replace degraded capacity and overbuild for the next 3-year period. Six total augmentations are expected over the 20-year lifetime of the BESS. The O&M costs include auxiliary load costs and an annual allowance for G&A costs, but exclude allowances for property taxes, land costs, and insurance. The O&M costs do not include the cost of energy to charge the system.

Table 6-12 — BESS O&M

Cost Category	Units	Wesleyville	Greenhill
Fixed O&M[1]	$/kW-year	45.00	43.00
Variable O&M[2]	$/MWh	0	0
Lifetime Battery Augmentation[3]	CAD	7,900,000	15,800,000
O&M Cost Notes			
1. Includes labor, material, contract services for technical O&M activities. Cost assumes execution of LTSA which includes extended warranty and capacity guarantees. Does not include costs associated with charging the BESS. Augmentation costs are not included. Non-technical O&M components are not included, such as land lease, property taxes, insurance costs, non-technical administrative overheads etc.			
2. Variable O&M expenses are assumed to be zero because maintenance is captured in Fixed O&M.			
3. Lifetime augmentation costs are presented in unescalated 2026 CAD. If the lifetime augmentation costs were to be capitalized up front, augmentation would add approximately $494/kW over the 20-year period.			

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7. ENVIRONMENTAL & REGULATORY REVIEW

7.1. CLEAN ELECTRICITY REGULATIONS

Federal Clean Electricity Regulations (CER)[13] were enabled under the Canadian Environmental Protection Act of 1999. The finalized CER was released at the end of 2024, setting binding greenhouse gas emission limits on fossil-fueled generation and establishing guidelines for the country to achieve net-zero in 2050. Under the CER, a unit is only held accountable if it has a capacity greater than or equal to 25 MW. The criteria knowingly exempt generation units in rural communities and smaller units used for backup power. Based on current assumptions, the new system built at Wesleyville would be less than 25 MW and thus not subject to the annual carbon dioxide emission limit beginning in 2035, while Greenhill would be over the 25 MW threshold and may be required to comply.

Under the CER, between 2035 and 2049 annual emissions are limited based on an intensity of 65 tonnes carbon dioxide (CO_2) per GWh. Using the formula provided in the CER:

CO_2 Emissions < [Capacity in MW] x [65 tonnes/GWh] x [8,760 hours] x 0.001 MW/GW

S&L calculates that the units at Greenhill would be capped at approximately 17,000 tonnes of CO_2/year. This equates to a limit of around 700 hours of run time per year, far more than the units are expected to operate.

Table 7-1 — Estimated Operation Limits Based on CER Carbon Limits

	Greenhill (30 MW)	Wesleyville (15 MW)
CO_2 Limit (tonnes)	17,082 tonnes	Not Applicable (<25 MW)
Annual Hour Limit	~ 700 hours	None

Compliance credits are earned for every one tonne of CO_2 that the unit emits below the cap. Those credits can be remitted within five years, but no later than 2049, in the instance that the unit exceeds the cap in a given year.

Beginning in 2050, the annual emissions are capped at a carbon intensity level of zero (0) tonnes per GWh. The CER does allow for an operator to deduct the emissions generated by the unit if it has been called

[13] Clean Electricity Regulations (SOR/2024-263), accessed March 31, 2026

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upon to run in an emergency circumstance. To qualify for the emergency deduction period, the following conditions must be met[14]:

> ***(a)*** *the electricity system operator has determined that there is an irresistible emergency event, whether natural or arising from human action, or the Minister has determined that there is a risk to human health and safety;*
>
> ***(b)*** *in the case of an irresistible emergency event, the event is outside the control of the electricity system operator and the responsible person;*
>
> ***(c)*** *the electricity system operator has determined that the event or risk referred to in (a) has triggered a disruption or significant risk of disruption to the electricity supply in the province in which the unit is located or in a contiguous province or state;*
>
> ***(d)*** *the electricity system operator directs the unit to generate electricity due to the event or risk referred to in (a) in order to alleviate or materially help alleviate a disruption or significant risk of disruption to the electricity supply in the province in which the unit is located or in a contiguous province or state;*
>
> ***(e)*** *the generation of electricity by the unit will alleviate or materially help alleviate a disruption or significant risk of disruption to the electricity supply in the province in which the unit is located or in a contiguous province or state; and*
>
> ***(f)*** *within seven days after the day on which the direction to generate electricity referred to in (d) is received, the responsible person notifies the Minister of that direction.*

Given the unit at GRH has historically been used to support emergency events, the carveout for emergency support in the CER would reduce the overall emissions burden of the unit; however, it would not compensate for emissions generated during typical peak load operations or other instances not specifically covered in the CER as emergencies. The way the CER is written today, Newfoundland Power may be required to purchase offset credits to compensate for non-emergency-related carbon emissions; however, S&L notes that the definition on what constitutes as emergency operation is vague in the CER. Specific cost and market details for the offset credits are not yet available.

Further clarification from Environment and Climate Change Canada and/or the Minister of the Environment may be required to assess applicability of the CER if the project moves into later stages of development.

[14] Clean Electricity Regulations (SOR/2024-263), Section 25, accessed March 31, 2026

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7.2. PROVINCIAL ENVIRONMENTAL ACTS

Newfoundland and Labrador has established province-level environmental goals through their Climate Change Mitigation Plan, which targets a 30% reduction in greenhouse gas (GHG) emissions by 2030 and a 60% reduction by 2040, as part of the overall strategy to reach net-zero by 2050. The industrial and electricity sectors, including oil production, accounted for 38% of emissions in 2023. Over 95% of emissions from these sectors are subject to annual greenhouse gas reduction targets through the provincial Management of Greenhouse Gas Act[15], which sets reporting requirements for facilities emitting over 15,000 tonnes of GHG annually. Based on the expected run times of the units at GRH and WES, S&L does not anticipate that either site will generate near 15,000 tonnes of GHG annually, and thus they will not be subject to the requirements of the Act.

The Air Pollution Control Regulations (NLR 11/22)[16], established in 2004 and revised in 2022, set out the ambient air quality standards and grant authority to local government agencies to create compliance mechanisms for emitting sources under their jurisdiction. According to the compliance guidelines[17] issued by the NL Department of Environment and Conservation, covered sources are broken down into five types, with corresponding requirements placed on each category. While WES and GRH do not qualify for Types I-IV due to their fuel requirements and/or operating hours, S&L anticipates that the units would be covered by Type V, which is described in the regulation as having "*an emission from a source that is not categorized as either a Type I, Type II, Type III or Type IV emission source, but which may have an emission that poses an environmental concern.*"

As a result, Newfoundland Power may be required to conduct a stack emissions test and register a dispersion model that includes all sources that account for at least 1% of the facility's total emissions[18].

7.3. PERMITTING

Projects that are subject to Newfoundland and Labrador's ambient air quality standards are required to obtain approval under the Environmental Protection Act and the NLR 11/22 from the Department of Environment and Climate Change (Pollution Prevention Division).

There is no generic NOx ppm or g/MWh limit in Newfoundland for diesel turbines in current regulations. Instead, Section 3 of NLR 11/22 requires that ambient air quality standards (AQS) is not exceeded. This

[15] Management of Greenhouse Gas Act SNL2016 CHAPTER M-1.001, accessed March 31, 2026
[16] Newfoundland and Labrador Regulation 11/22 *Air Pollution Control Regulations 2022,* accessed March 31, 2026
[17] https://www.gov.nl.ca/eccc/files/env-protection-science-gd-ppd-009-4.pdf
[18] Newfoundland and Labrador Department of Environment and Conservation *Determination of Compliance with the Ambient Air Quality Standards,* page 10

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allows the Minister to impose conditions or an air quality management plan if it is needed. The following table lists the AQS for nitrogen dioxide in the province.

Table 7-2 — AQS for Nitrogen Dioxide 2022 (NLR 11/22)

Pollutant	Air Quality Standard
NO_2	**1-hr NO_2**: **400 µg/m³** (213 ppb)
NO_2	**24-hr NO_2**: **200 µg/m³** (106 ppb)
NO_2	**Annual NO_2**: **100 µg/m³** (53 ppb, annual arithmetic mean)

The application must contain an air quality assessment that relies on several elements, including an evaluation demonstrating that emissions from the facility will be controlled using Best Available Control Technology (BACT), as defined in Section 6 of NLR 11/22. Table 7-3 includes control methods that are expected to qualify as BACT for new simple cycle and diesel-fired combustion turbines in Newfoundland. For simple-cycle, diesel-fired combustion turbines in Newfoundland and Labrador, BACT is determined through a top-down process that identifies all technically feasible emission control options, evaluates them against site-specific constraints, and then selects the most effective control that remains technically proven, reliable in comparable applications, and economically feasible.

Section 6 requires the BACT for new or modified sources, defined as the most effective / most stringent, proven reliable and economically feasible. The BACT process is determined through a structured top-down process that identifies all technically feasible emission control options, screens the options based on practicality and site constraints, evaluates their environmental performance and economic feasibility, and then selects the most effective control method that remains both technically and economically reasonable.

The technically feasible emission control options for Newfoundland Power's Wesleyville and Greenhill include ultra-low sulfur diesel (ULSD) fuel selection plus good combustion practices, dry low NO_x (DLN) combustion system, water or steam injection at the combustors for thermal NO_x suppression, and selective catalytic reduction (SCR) as a post-combustion NO_x control system. The following table discusses the BACT options, evaluates the technical and economic feasibility, and selects the most effective control(s).

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Table 7-3 — Best Available Control Technology Assessment for CTs

BACT	Site Constraints and Technical Feasibility	Economic Feasibility	Selection of BACT
Fuel Selection: Ultra-low sulfur diesel plus good combustion practices	Feasible and can be combined with other options.	Feasible and can be combined with other options.	Selected
Dry Low NOx (DLN) combustion system	DLN is only available with certain manufacturers (see note below)	DLN technology offers substantial Nox reduction with a lower capital as compared to an SCR.	Selected
Water or Steam injection	The remote location has very limited water availability making water/steam injections not feasible.	The large volumes of demineralized water storage would be required due to the limited water availability on site.	Not selected
SCR	An SCR is technically a feasible option though it does require extra space and infrastructure.	The units are expected to operate at less than 300 hours per year, primarily for emergency-based support. An SCR would have a high cost per tonne of NO_x removed.	Not selected

Given the remote locations of Greenhill and Wesleyville, the limited water supply at the sites, and the limited estimated annual hours of operation for the units, an SCR system is not considered economically reasonable BACT. As such, the BACT analysis concludes that SCR is not required. Instead, BACT for this project is defined as exclusive use of ULSD combined with good combustion practices, plus DLN combustion system. The final selection should be in compliance with applicable ambient air quality standards.

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8. RECOMMENDATIONS

Newfoundland Power is seeking to replace its over 50-year-old combustion turbines at Greenhill and Wesleyville with comparably-sized resources capable of providing sustained system support and reliability. The following types of resources have been considered as replacement options at the sites.

- Combustion Turbines (CTs)
  - Modular Units
  - Traditional Units
- Reciprocating Internal Combustion Engines
- Battery Energy Storage Systems

This section combines the various pros and cons, as well as the cost estimates of the different technologies presented in the prior sections, into recommendations for Newfoundland Power related to the generation replacement at Greenhill and Wesleyville.

8.1. TECHNOLOGY COMPARISON

Combustion turbines, reciprocating engines, and battery energy storage systems are unique technologies with different operating characteristics and capabilities. The key criteria listed below, along with the estimated resource costs, are used to help evaluate each of the potential replacement options.

- Units are reliable in harsh weather conditions, particularly those that are common along the Newfoundland coasts in the winter
- Units are capable of quickly starting and load ramping
- The units are well-suited to providing grid support and peaking services
  - Related to grid support, the unit needs to be able to provide synchronous condensing capability or equivalent electrically
- Units can support the system in an emergency, for extended transmission outages and supply shortfall scenarios
- For thermal technologies considered, the units need to be able to be operable on diesel fuel using minimal process water

The following table compares each technology against Newfoundland Power's key needs for the new resources. A description of how each resource meets these needs is also provided.

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Table 8-1 — Technology Comparison

Technology	Technology Evaluation	Capital and O&M Costs Values in CAD
Modular Combustion Turbine	**Reliability in Harsh Winter Weather:** Modular CTs are deployed throughout the globe in harsh winter conditions and have a proven track record of strong reliability. To maximize unit reliability, supporting equipment / balance of plant must also be designed for the Newfoundland coastal climate. **Capable of Quick Start and Ramping:** Modular CTs are capable of quick starting and ramping (within minutes) **Ability to Provide Grid Support / Peaking Services:** Combustion turbines are used throughout the energy industry to provide grid support and peaking services **Synchronous Condensing Capability or Electronic Equivalent**: Combustion turbines are frequently used as synchronous condensers. Many OEMs of modular units (as well as third parties) have synchronous condensing packages that can be added to the unit **Ability to Support in Emergencies and Extended Outages:** As a generator with quick-response capabilities, a modular CT is well-equipped to support the electrical system in an emergency event including extended transmission outages and supply shortfall scenarios. The unit can operate for long periods of time, provided there is adequate fuel available to support continued operation **Ability to Operate on Diesel Fuel with Minimal Process Water:** A number of OEMs offer modular CTs that are capable of operating on diesel fuel. Furthermore, dry low NO_x systems do not require water **Estimated Resource Lead Time**: 3 to 4 years, depending on OEM **Estimated Lifespan**: 30 to 40 years	**Overnight Capital Cost:** GRH: $4,151 CAD per kW WES: $5,013 CAD per kW **Overnight Capital Cost (Annualized)[19]:** GRH: $119 CAD per kW-yr WES: $143 CAD per kW-yr **FOM:** GRH: $21.50 CAD $/kW-year WES: $26.50 CAD $/kW-year **VOM:** GRH $0.50 CAD $/MWh WES: $0.50 CAD $/MWh

[19] The annualized capital cost calculation is based on a service life of 35 years for a modular CT. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.

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Technology	Technology Evaluation	Capital and O&M Costs Values in CAD
Traditional CT	**Reliability in Harsh Winter Weather:** Similar to modular CTs, traditional CTs are deployed throughout the globe in harsh winter conditions, where they have a similar reliable pedigree. The building itself provides significant protection, in addition to making it easier to service the unit when weather is challenging. Compared to a modular CT, a traditional unit may be marginally better protected from the elements, depending on the enclosure design **Capable of Quick Start and Ramping:** Traditional CTs are capable of quick starting and ramping (within minutes) **Ability to Provide Grid Support / Peaking Services:** Combustion turbines are used throughout the energy industry to provide grid support and peaking services **Synchronous Condensing Capability or Electronic Equivalent**: Combustion turbines are frequently used as synchronous condensers. It is common in the industry to purchase a traditional CT with the ability to operate as a synchronous condenser **Ability to Support in Emergencies and Extended Outages:** Similar to a modular CT, a traditional CT is well suited for this purpose **Ability to Operate on Diesel Fuel with Minimal Process Water:** Many traditional CTs come with the ability to operate on diesel fuel. Additionally, dry low NO_x systems do not require water to operate **Estimated Resource Lead Time**: 3 to 4 years, depending on OEM **Estimated Lifespan**: 30 to 40 years	**Overnight Capital Cost:** GRH: $4,257 CAD per kW WES: $5,079 CAD per kW **Overnight Capital Cost (Annualized)[20]:** GRH: $122 CAD per kW-yr WES: $145 CAD per kW-yr **FOM:** GRH: $21.50 CAD $/kW-year WES: $26.50 CAD $/kW-year **VOM:** GRH $0.50 CAD $/MWh WES: $0.50 CAD $/MWh

[20] The annualized capital cost calculation is based on a service life of 35 years for a traditional CT. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.

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Technology	Technology Evaluation	Capital and O&M Costs Values in CAD
RICE	**Reliability in Harsh Winter Weather:** RICE units have a proven track record of strong reliability in harsh winter conditions. Typical RICE units are installed in buildings; thus, they are shielded from the elements **Capable of Quick Start and Ramping:** RICE units are capable of quick starting and ramping (within minutes) **Ability to Provide Grid Support / Peaking Services:** Similar to combustion turbines, RICE units are used throughout the energy industry to provide grid support and peaking services **Synchronous Condensing Capability or Electronic Equivalent**: RICE units are less commonly used as synchronous condensers; however, it is technically possible. OEMs can include the necessary equipment to allow for synchronous condenser operation (such as Wärtsilä, which completed its first synchronous condensing RICE project in 2025). **Ability to Support in Emergencies and Extended Outages:** Similar to both a modular and traditional CT, a RICE unit is well suited for this purpose **Ability to Operate on Diesel Fuel with Minimal Process Water:** RICE operation on diesel fuel is common in the industry. A RICE unit can operate without significant water consumption. **Estimated Resource Lead Time**: 2 to 4 years, depending on OEM **Estimated Lifespan**: 30 to 40 years **Additional Notes**: Given the large weight and size of RICE units, it may require additional planning and logistics coordination to transport the units to the GRH and WES sites	**Capital Cost:** GRH: $4,903 CAD per kW WES: $5,505 CAD per kW **Overnight Capital Cost (Annualized)[21]:** GRH: $140 CAD per kW-yr WES: $157 CAD per kW-yr **FOM:** GRH: $23.00 CAD $/kW-year WES: $23.00 CAD $/kW-year **VOM:** GRH $5.50 CAD $/MWh WES: $5.50 CAD $/MWh

[21] The annualized capital cost calculation is based on a service life of 35 years for a RICE resource. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.

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Technology	Technology Evaluation	Capital and O&M Costs Values in CAD
BESS	**Reliability in Harsh Winter Weather:** BESS units are reliable in harsh winter conditions, especially when specifically designed with conditioned enclosures / cold-climate packages. **Capable of Quick Start and Ramping:** BESS units can provide support to the electrical system near instantaneously **Ability to Provide Grid Support / Peaking Services:** A BESS resource is one of the best available at providing grid support services, specifically because of how quickly it can respond. S&L recommends a BESS with grid-forming inverters due to the remoteness of GRH and WES. It can also support peaking services provided it is sufficiently charged. **Synchronous Condensing Capability or Electronic Equivalent**: When equipped with grid-forming inverters, a BESS resource can provide similar support to what a synchronous condenser can provide **Ability to Support in Emergencies and Extended Outages:** A BESS resource is charge limited. As such, it is not well suited to respond to emergency events such as extended transmission outages or supply shortfall scenarios if the event lasts for a long period of time (i.e., many hours or days) **Ability to Operate on Diesel Fuel with Minimal Process Water:** A BESS resource does not require fuel or water to operate. **Estimated Resource Lead Time**: 6 months to 1 year **Estimated Lifespan**: 20 years **Additional Notes**: A BESS' use case overlaps with a thermal resource, but it can also provide additional / different system support such as load / peak shifting and additional ancillary services. A BESS would have to be periodically augmented to maintain consistent performance levels. Following discharge events, a BESS must be recharged from the local electrical system, which imposes a temporary load on the grid.	**Capital Cost:** GRH: $2,709 CAD per kW WES: $3,113 CAD per kW *+ approximately $494/kW in lifetime augmentation costs* **Overnight Capital Cost (Annualized)[22]:** GRH: $135 CAD per kW-yr WES: $156 CAD per kW-yr **FOM:** GRH: $43.00 CAD $/kW-year WES: $45.00 CAD $/kW-year **VOM:** GRH $0.00 CAD $/MWh WES: $0.00 CAD $/MWh

The detailed evaluations above are summarized in the table below to provide an at-a-glance comparison of the technologies against Newfoundland Power's key requirements.

[22] The annualized capital cost calculation is based on a service life of 20 years for a BESS resource. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.

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Table 8-2 — High-Level Comparison of Technology Characteristics

Criteria	Modular CT	Traditional CT	RICE	BESS
Reliable in Harsh Winter Weather?	Yes	Yes	Yes	Yes
Capable of Quick Start and Ramping?	Yes	Yes	Yes	Yes
Can Provide Grid Support / Peaking Services?	Yes	Yes	Yes	Yes (Charge Limited)
Synchronous Condensing Capability (or Electrical Equivalent)?	Yes	Yes	Yes, Less Common	Yes
Provide Support in Emergencies and Extended Outages?	Yes	Yes	Yes	Uncertain (Charge Limited – Depends on Emergency Event)
Operate on Diesel Fuel with Minimal Process Water	Yes	Yes	Yes	N/A
Lead Time	3-4 Years	3-4 Years	2-4 Years	< 1 Year
Estimated Lifespan	30 to 40 Years	30 to 40 Years	30 to 40 Years	20 Years
Overnight Capital Cost (CAD/kW)[23]	GRH: $4,151 WES: $5,013	GRH: $4,257 WES: $5,079	GRH: $4,903 WES: $5,505	GRH: $2,709 WES: $3,113
Overnight Capital Cost (Annualized)[24] (CAD/kW-yr)	GRH: $119 WES: $143	GRH: $122 WES: $145	GRH: $140 WES: $157	GRH: $135 WES: $156
FOM (CAD/kW-yr)	GRH: $21.50 WES: $26.50	GRH: $21.50 WES: $26.50	GRH: $23.00 WES: $23.00	GRH: $43.00 WES: $45.00
VOM ($/MWh)	GRH $0.50 WES: $0.50	GRH $0.50 WES: $0.50	GRH $5.50 WES: $5.50	GRH $0.00 WES: $0.00

[23] Note that an additional CAD $494/kW is estimated for lifetime BESS augmentation costs. These costs are not included in the overnight capital costs listed in the table.

[24] The annualized capital cost calculation is based on a service life of the applicable resource. This service-life-normalized estimate is a simplified way of incorporating service life into a cost metric by dividing the $/kW cost by the estimated service life. This metric does not capture the full complexity of extrapolating capital cost over the life of an asset. It is intended to be considered in conjunction with the capital cost estimates as an additional point of reference that incorporates expected asset life.

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8.2. TECHNOLOGY RECOMMENDATIONS

Given the needs of Newfoundland Power and the capabilities of the different technologies considered, S&L recommends that combustion turbines be first considered as the option to replace the existing generators at the GRH and WES sites. Further discussion of this recommendation is provided below:

Combustion turbines are recommended over RICE based on synchronous condensing capability and constructability. While RICE units can be fitted with synchronous condensing capability, it is more commonly installed on combustion turbines. For example, Wärtsilä, one of the world's largest engine manufacturers, completed its first project where it incorporated synchronous condensing capability into a RICE project in 2025[25]. As such, S&L considers there to be marginally lower risk for Newfoundland Power in choosing combustion turbines over RICE from the perspective of synchronous condensing capability. Additionally, based on S&L's site visits, it would likely be more challenging to transport the heavier and larger-sized RICE units to the remote GRH and WES sites. As such, S&L considers there to be lower technical and implementation risk for Newfoundland Power in choosing combustion turbines over RICE. From a cost perspective, the analysis also indicates that combustion turbines have a marginally lower estimated overnight capital cost and O&M cost than RICE units.

Combustion turbines are recommended over BESS resources primarily due to the BESS resource's finite energy reservoir and thus inability to provide continuous power injection during extended system outages / emergency events. It is important to note that BESS units are an option for Newfoundland Power that would be able to satisfy many of the system needs; however, it is also a fundamentally different technology than a thermal generator that can offer different benefits to the system. For example, while BESS resources are well-suited to load / peak shifting and ancillary services / grid support, their ability to provide sustained system support is finite and limited by the resource's state of charge. As a result, a BESS resource would not be able to sustain continuous output during extended outages (many hours / days in duration) or prolonged supply shortfall scenarios in the same manner as a thermal generator. This use case is of concern to Newfoundland Power given Newfoundland's geography as an island with limited on-island generators. Longer duration BESS resources (i.e., 8 or 12 hours instead of 4 hours) could be considered; however, BESS capital costs roughly scale 1 to 1 with the number of BESS modules installed; thus, 8 or 12 hour BESS resources will be less cost competitive than a 4 hour BESS resource. It is also important to note that while the capital cost of a 4 hour BESS resource is lower than for a combustion turbine, the operational life of a BESS resource at approximately 20 years is shorter than what would be expected for a combustion turbine at 30 to 40 years. As such, a BESS resource would require significant re-investment

[25] https://www.wartsila.com/media/news/09-12-2025-wartsila-s-first-power-plant-with-synchronous-condenser-feature-to-support-renewable-energy-integration-for-australian-mining-operation-3693751

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after 20 years, likely involving replacement of battery modules (while potentially retaining inverter and balance-of-plant infrastructure), for continued operation beyond its initial 20-year design life.

8.2.1. Modular Versus Traditional Combustion Turbines

There were two types of combustion turbines evaluated for this analysis: modular units and traditional units. Both have unique benefits and drawbacks, and both are considered capable of meeting Newfoundland Power's core operational needs. The following section compares the two types of turbine categories.

Both modular and traditional combustion turbines would help Newfoundland Power meet its most critical needs – specifically being able to provide grid support and peaking services, provide backup generation and extended-duration emergency response, ramp-up quickly, operate in harsh winter conditions, operate on diesel fuel, and have synchronous condenser capability. However, there are some unique characteristics of both combustion turbine types, as described below.

Given that a modular combustion turbine arrives at the site factory-assembled on a skid in a more "plug-and-play" state, they can be deployed more rapidly than a traditional unit, which requires more support infrastructure to be built and thus has longer construction timelines. A modular combustion turbine will also require less construction labor to install. These characteristics reduce installation complexity and exposure to weather-related schedule risk, which is beneficial for the remote GRH and WES sites. In addition, modular units typically require less physical space than comparably sized traditional units, which can simplify site layout and integration.

Both modular and traditional combustion turbines are capable of being operated remotely. Given the potential for harsh weather conditions in coastal Newfoundland, adequate protection from the elements is an important consideration. Modular units are enclosed and protected from elements; however, it would be important for the balance of plant / supporting systems to be designed to withstand Newfoundland's climate in order to maximize unit reliability and life.

A benefit of traditional units is that they would be fully covered within a custom enclosure, providing significant protection from harsh winter conditions. Similarly, the site layout can be more customized and there are typically more turbine model / manufacturer options available. Likewise, maintenance activities can be marginally easier to accomplish on a traditional combustion turbine as there is typically more room to perform needed work within the enclosure.

From a cost perspective, this analysis indicates that the estimated capital costs for modular and traditional combustion turbines are generally comparable. Modular units are estimated to have a marginally lower

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overall cost, driven primarily by reduced installation labor and shorter construction schedules associated with the skid-mounted configuration.

Accordingly, S&L considers both modular and traditional combustion turbines to be viable and appropriate options for Newfoundland Power. However, given the shorter construction timeline, reduced installation complexity, and small cost advantage, S&L slightly favors modular combustion turbines for Newfoundland Power's GRH and WES applications. However, traditional units offer certain offsetting benefits related to enclosure design, layout flexibility, and ease of maintenance; therefore, they also remain a viable alternative to replace the existing units at GRH and WES.

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APPENDIX E:

Cost Estimates

Gas Turbine Replacement Cost Estimate

Final Report

Stantec

Prepared for:
Newfoundland Power

Prepared by:
Stantec Consulting Ltd.

Date:
September 28, 2026

Project/File:
137026073

Stantec Consulting Ltd.

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Revision	Description	Author	Date	Quality Check	Date	Independent Review	Date
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Executive Summary

Newfoundland Power (NP) operates two (2) remote combustion turbine generating facilities located at Greenhill and Wesleyville that provide critical emergency generation and electrical system support to the Island Interconnected System. The existing facilities have reached the end of their practical service lives and are becoming increasingly difficult to maintain and support. As part of its long-term generation strategy, NP retained Stantec Consulting Ltd. (Stantec) to complete an Association for the Advancement of Cost Engineering (AACE) Class 3 engineering study and opinion of capital cost to support future project development and Public Utilities Board (PUB) approval activities.

The study evaluated replacement of the existing combustion turbine facilities with modern liquid-fuelled combustion turbine technology while maximizing the use of existing site infrastructure where practical. The assessment included development of a Design Basis Memorandum (DBM), concept-level engineering, environmental and regulatory review, Class 3 opinion of capital cost, preliminary construction schedules, risk identification, and development of supporting project execution assumptions.

The study concludes that replacement of both generating facilities is technically feasible and can be implemented within the constraints of the existing sites. At Greenhill, the preferred concept consists of complete replacement of the existing generating facility, including a new combustion turbine building, balance-of-plant systems, fuel storage facilities, electrical interconnection infrastructure, and associated civil works. At Wesleyville, the preferred concept involves replacement of the generation equipment while reusing portions of the existing building and site infrastructure where practical.

The resulting AACE Class 3 opinion of capital cost indicates an anticipated total project cost of approximately $122.1 million CAD for Greenhill and $71.0 million CAD for Wesleyville, including indirect costs, market escalation factor for combustion turbine (CT) cost given the state of the CT market, and contingency appropriate for the level of project definition. These estimates are intended to support project planning and regulatory submissions and should be refined through subsequent engineering and equipment procurement phases. Overall escalation and financing costs as well as substation costs will be determined by NP.

Preliminary project schedules indicate overall project durations of approximately five (5) years from approval to commercial operation, driven primarily by combustion turbine procurement lead times. Execution of engineering, environmental approvals, procurement, and site preparation activities prior to turbine delivery will be essential to achieving the target in-service dates.

This report summarizes the study findings and recommendations. Detailed technical information, cost estimates, schedules, risks, assumptions, drawings, and supporting analyses are provided in the accompanying appendices.

Acronyms / Abbreviations

Acronym / Abbreviation	Full Name
DBM	Design Basis Memorandum
CT	Combustion Turbine
GA	General Arrangement
GRH	Greenhill
HV	High Voltage
I&C	Instrumentation and Controls
NL	Newfoundland and Labrador
NP	Newfoundland Power
OPCC	Opinion of Probable Construction Cost
PFD	Process Flow Diagram
SLD	Single Line Diagram
WES	Wesleyville

Glossary

Term	Definition
Allowance	An estimated amount included in the OPCC for scope, quantities, or costs that are not fully defined at the current stage of project development.
Assumption	A condition, input, or interpretation used to prepare the report or OPCC where final information was not available at the time of preparation.
Basis of Design	A separate supporting document that contains the design and schedule basis information used to support the OPCC.
Budgetary Pricing	Preliminary pricing provided by vendors or suppliers for planning and estimating purposes and subject to confirmation during later project phases.
Clarification	A statement that defines how a scope item, estimate input, responsibility, or limitation has been interpreted for this report.
Contingency	An amount included in the estimate to account for expected uncertainty within the defined project scope at the current level of project definition.
Exclusion	A scope item, cost, activity, or requirement that is not included in this report or the OPCC unless specifically noted otherwise.
Opinion of Probable Capital Cost	A planning-level estimate of probable capital cost based on the information available at the time of preparation and subject to refinement as project definition advances.
Permitting Pathway	The anticipated sequence of environmental or regulatory approvals, reviews, and confirmations required before project execution.
Risk	An uncertain condition or event that may affect project cost, approvals, implementation, scope, or future project development.

1 Project Background

NP owns and operates combustion turbine generating facilities at Greenhill and Wesleyville. These units provide emergency generation capacity and support system reliability throughout the Newfoundland electrical grid. The existing facilities were originally installed several decades ago and, despite various upgrades and refurbishments, have reached the point where replacement represents the preferred long-term solution.

In 2026, Stantec completed a generation fleet review that identified both facilities as candidates for retirement due to advancing equipment age, increasing maintenance requirements, declining equipment supportability, and operational risks associated with continued long-term operation.

To support future regulatory filings and internal capital planning activities, NP retained Stantec to undertake a Class 3 engineering study and cost estimate. The study was intended to establish a technically defensible project basis, identify environmental and permitting requirements, develop concept-level facility layouts, prepare preliminary construction schedules, and generate representative capital cost estimates suitable for regulatory review and project planning.

2 Scope and Methodology

The study was completed and generally aligned with AACE Recommended Practice No. 18R-97 for Class 3 estimating where possible.

The scope of work included:

- Development of a Design Basis Memorandum.
- Assessment of replacement combustion turbine configurations.
- Site-specific civil, structural, mechanical, electrical, and controls concepts.
- Environmental and regulatory assessments.
- Identification of permitting requirements.
- Development of preliminary project execution schedules.
- Preparation of AACE Class 3 opinion of capital cost.
- Development of project assumptions, clarifications, and risk registers.
- Preparation of concept-level drawings and supporting documentation.

Engineering activities focused on establishing a practical basis for future detailed design rather than producing construction-ready documentation. Existing site information, client-provided information, vendor budgetary pricing, historical project benchmarking, and engineering judgement were utilized throughout the study. Detailed design, field investigations, geotechnical programs, environmental field studies, and procurement activities are outside the scope of this phase and would form part of subsequent project development stages.

3 Recommended CT Replacement Concepts

The recommended replacement concepts utilize modern liquid-fuelled combustion turbine technology sized to satisfy Newfoundland Power's operational requirements while maintaining compatibility with the existing transmission infrastructure at each site.

Greenhill

The preferred Greenhill concept consists of complete facility replacement. Major components include:

- New combustion turbine package.
- New control building.
- Exhaust system and stack.
- Fuel forwarding and fuel storage systems.
- Black start diesel generator.
- Electrical interconnection equipment.
- Control systems and communications infrastructure.
- Civil site development and associated foundations.
- Associated balance-of-plant infrastructure.

The Greenhill facility is expected to require significant civil works and complete replacement of most existing generating infrastructure. The concept incorporates modern environmental, safety, and operational requirements while maintaining compatibility with existing transmission connections.

Wesleyville

The preferred Wesleyville concept consists of replacement of the existing combustion turbine equipment while maximizing utilization of selected existing infrastructure where practical. Major project components include:

- New combustion turbine package.
- Building modifications following removal of the existing unit
- Exhaust system stack.
- Fuel forwarding and fuel storage systems
- Black start diesel generator.
- Electrical interconnection equipment.
- Controls system and communications infrastructure.
- Civil site development and associated foundations.
- Associated balance-of-plant infrastructure

This approach minimizes overall capital investment while still achieving the reliability, maintainability, and operational improvements required for long-term operation.

Detailed design criteria, engineering assumptions, equipment philosophy, and concept drawings are provided within the Design Basis Memorandum and supporting appendices as outlined in the following chapters.

4 Environmental and Regulatory Considerations

An assessment of applicable federal and provincial environmental and regulatory requirements was completed as part of the study. The review included environmental assessment requirements, permitting obligations, air quality considerations, greenhouse gas requirements, contamination considerations, and environmental risks associated with project execution.

Both projects are expected to trigger environmental assessment requirements under the Newfoundland and Labrador Environmental Protection Act due to the nature and capacity of the generating facilities. Environmental registration with the applicable regulatory authorities will therefore be required prior to project implementation.

The review determined that the projects are not anticipated to require a federal Impact Assessment under the Impact Assessment Act based on the current project scope. However, a number of environmental approvals, permits, and authorizations will be required during project development and implementation. These approvals will include environmental assessment review, construction permits, air emissions approvals, fuel storage approvals, and various construction-related environmental authorizations.

Particular attention should be given to:

- Existing site contamination risks.
- Fuel storage and handling requirements.
- Air emissions and noise compliance.
- Hazardous materials management.
- Waste management and demolition planning.
- Environmental protection planning during construction.

Based on current information, there are no identified environmental issues that would preclude project implementation. However, additional environmental investigations, permitting activities, and regulatory engagement will be required during subsequent project phases.

The Clean Electricity Regulations (CER) apply to fossil fuel-fired generating units greater than 25 MW_e that are directly or indirectly connected to a North American Electric Reliability Corporation (NERC) regulated electricity system. With a planned capacity exceeding 25 MW_e, the Greenhill facility is expected to meet the threshold for CER applicability. Based on the projected operating profile, Greenhill is not expected to exceed CER emissions limits between 2035 and 2050. While the CER establishes a net-zero emissions requirement after 2050, limited compliance mechanisms remain available, including provisions for emergency operation and emissions offsetting.

Detailed environmental assessments and supporting information are included in the Design Basis Memorandum in Appendix A.

5 Opinion of Probable Capital Cost

The Opinion of Probable Capital Cost (OPCC), located in Appendix B, was developed using information available at the time of preparation, including Newfoundland Power-provided documentation, existing site information, site photographs, available historical geotechnical and survey information, budgetary vendor pricing, and the separate Design Basis Memorandum document (Appendix A). The estimate reflects the current level of project definition and is subject to refinement as additional information becomes available. The OPCC is intended to support planning, budgeting, and decision-making at the current stage of project definition.

Major cost considerations include combustion turbine equipment, black start generation, fuel storage, switchgear, high-voltage cabling, site-related construction costs, discipline allowances, indirect costs, and contingency. Budgetary pricing and allowances should be reviewed as the project advances and vendor, procurement, and execution assumptions are confirmed.

The OPCC should be read together with the assumptions, clarifications, exclusions, and risks identified in the Basis of Estimate in Appendix C and this report. The estimate is not intended to represent a final construction value and does not replace future estimate updates required as the project definition, procurement approach, site information, permitting requirements, and execution strategy are further developed.

The resulting total installed costs, excluding escalation, financing and substation costs are summarized below in Table 1. A market escalation factor has been included for the CTs.

Table 1: AACE Opinion of Probable Capital Cost – Greenhill and Wesleyville

Site	Opinion of Probable Capital Cost
Greenhill	$122.1 Million
Wesleyville	$71.0 Million

The largest cost contributors for both projects are:

- Combustion turbine supply.
- Mechanical installation.
- Civil and structural works.
- Electrical interconnection infrastructure.
- Contractor indirects.
- Project indirects.
- Combustion turbine escalation
- Contingency allowances.

Estimate development utilized vendor budget pricing, benchmarked labour productivity assumptions, historical project experience, and engineering quantity take-offs developed during the study. Detailed estimate methodology, assumptions, and cost breakdowns are provided within the Basis of Estimate and cost estimate appendices.

5.1 Contingency and Monte Carlo Assessment

Monte Carlo simulation confirms that the AACE Class 3 cost estimates provide a robust basis for project planning and regulatory review. At a P90 confidence level, total project costs are estimated at approximately $122.1 million for Greenhill and $71.0 million for Wesleyville. The primary drivers of cost uncertainty are turbine installation activities, CT escalation, and project indirect costs. Detailed assessment results are provided in Appendix D – Monte Carlo Assessment.

6 Schedule Summary

Preliminary construction execution schedules were developed to support project planning and estimate development. The schedules incorporate engineering, procurement, environmental approval, construction, commissioning, and startup activities.

The schedules indicate overall project durations of approximately five (5) years. Major equipment procurement, particularly combustion turbine delivery, is the principal schedule driver. Recent vendor and client reviews indicate turbine delivery lead times approaching four (4) years and have been reflected within the schedule assumptions.

Key milestones include:

- Regulatory approvals.
- Completion of detailed engineering.
- Turbine procurement.
- Site preparation and civil construction.
- Mechanical and electrical installation.
- Commissioning and startup.
- Commercial operation.

To mitigate schedule risk, it is recommended that environmental approvals, engineering development, and procurement planning commence as early as practical following project approval.

Detailed project schedules are included in the Design Basis Memorandum (DBM) appended in Appendix A.

7 Key Risks, Assumptions, and Exclusions

The project cost and schedule projections are dependent upon a number of assumptions that should be reviewed during future project development phases.

Key risks include:

- Long-lead combustion turbine procurement.
- Market escalation and supply-chain volatility.
- Regulatory approval timelines.
- Unknown subsurface conditions.
- Environmental assessment outcomes.
- Evolving equipment pricing.
- Construction labour availability.

Primary assumptions include:

- Availability of modern liquid-fuel combustion turbine technology.
- Continued use of existing transmission interconnections.
- Typical permitting pathways.
- Brownfield development conditions.
- Concept-level design development consistent with OPCC estimating.

Major items not completed during the course of this study include:

- Detailed design engineering.
- Detailed geotechnical investigations.
- Environmental field studies.
- Procurement activities.
- Construction activities.
- Final vendor quotations.
- Asset decommissioning assessments beyond those identified within the study basis.

8 Conclusions and Recommendations

The Gas Turbine Replacement Cost Estimate study demonstrates that replacement of the existing Greenhill and Wesleyville combustion turbine facilities is technically feasible and provides a practical long-term solution for maintaining reliable emergency generation capacity within the Newfoundland Power system.

The recommended concepts establish a sound basis for future project development and support advancement toward regulatory approvals and future capital authorization. The resulting AACE Class 3 estimates indicate total project costs of approximately $122.1 million for Greenhill and $71.0 million for Wesleyville, with overall project durations of approximately five years driven primarily by combustion turbine procurement lead times.

It is recommended that Newfoundland Power proceed with:

- Advancement to the next phase of engineering development.
- Early environmental and regulatory engagement.
- Refinement of project execution strategy and procurement planning.
- Continued monitoring of combustion turbine market availability.
- Further refinement of capital costs and project risks as design development progresses.

The Design Basis Memorandum, Basis of Estimate, cost estimates, schedules, and concept drawings collectively provide the technical basis for subsequent project development and regulatory submissions.

Appendix A Design Basis Memorandum (DBM)

Design Basis Memorandum

Newfoundland Power Combustion Turbine Class 3 Study

Stantec

Prepared for:
Newfoundland Power

Prepared by:
Stantec Consulting Ltd.

Date:
September 28, 2026

Project:137026073
137026073 -DBM-0001

Stantec Consulting Ltd.

Revision Record

Rev	Description	Author	Date	Reviewed By	Date	Approved By	Date
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0	Final Report	T. Bryden	2026-08-07	B. Jones	2026-08-12	C. van Driel	2026-08-13
1	Final Report	T. Bryden	2026-09-14	B. Jones	2026-09-16	C. van Driel	2026-09-18
2	Final Report	T. Bryden	2026-09-25	B. Jones	2026-09-25	C. van Driel	2026-09-25

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1 Project Summary

Newfoundland Power (NP) operates two (2) liquid fueled combustion turbine generators (CTGs) located on the Island of Newfoundland: one located at the Greenhill site and the other located at the Wesleyville site. These units are utilized as emergency back-up power generators as well as electrical power system support. Both original units were purchased in the 1969 – 1975 timeframe, and have undergone a number of equipment upgrades, repairs, and modernizations over the years to remain in service.

The existing Greenhill CTG has a nameplate of 25 MW_e, but is derated to 20 MW_e, and is located in the community of Grand Bank, off Route 210 on the Burin Peninsula, on an approximately two (2) acre site. There are two (2) older fuel storage tanks, installed in 2002, and a third tank installed in 2014, each with a capacity of 100,000 litres. The power plant is connected to the island grid via transmission lines 301L and 305 L, which operate at 66 kV. The existing fuel tanks and generating building are to be demolished as part of the replacement project.

The existing Wesleyville CTG has a nameplate of 14.7 MW_e, derated to 8 MW_e, and is located in the community of New-Wes-Valley, off Route 320 on a 0.6-acre site. A new building was constructed in 2003 when the unit was relocated from Salt Pond, Burin and roof repairs occurred around the exhaust stack in 2014. It is connected to the island grid via transmission line 116 L, which operates at 66 kV. The existing two (2), 75,000 litre fuel tanks will be replaced as part of the replacement project, and the existing building will be reused.

Stantec completed a thermal generation fleet review in 2026 and concluded that both the Greenhill and Wesleyville facilities have reached the end of their service lives.

2 Scope Definition

NP has assigned Stantec to provide engineering services to support NP with a Class 3 Study and Cost Estimate, in accordance with the Association for the Advancement of Cost Engineering (AACE) Recommended Practice No. 18R-97 (latest edition) Cost Estimate Classification System as Applied in Engineering, Procurement, and Construction for the Process Industries, for their submission to the Public Utility Board (PUB) for approval of these site refurbishments at Wesleyville and Greenhill.

3 Project Location Map

The location of Greenhill Station is shown on Figure 1.



Figure 1: Greenhill Station – Project Location

Picture Courtesy: Google Maps

The location of Wesleyville Station is shown on Figure 2



Figure 2: Wesleyville Station – Project Location

Picture Courtesy: Google Maps

4 Codes, Standards, and Specifications

The design and construction of this project will adhere to the specified standards and guidelines outlined below:

- API
    - API Standard 2350, 5th Edition - Overfill Prevention for Storage Tanks in Petroleum Facilities
- CSA
    - CSA Z245.20: 22 - Plant-applied external coatings for steel pipe
    - CSA B51-03 - Boiler, Pressure Vessel, and Pressure Piping Code
    - ANSI/ASME B31.1 - Power Piping Code
    - ASME B16 - Fitting and Valves Package
    - CSA B139 - Installation Code for Oil-Building Equipment
    - NFC - National Fire Code
    - NLR 58/03 - Storage and Handling of Gasoline and Associated Products Regulations
    - ULC S601 - Standard for Shop Fabricated Steel Aboveground Tanks for Flammable and Combustible Liquids
    - CSA A23.1-19/A23.2-19 - Concrete Materials and Methods of Concrete Construction/Test Methods and Standard Practices for Concrete
    - CSA A23.3-14 - Design of Concrete Structures
    - CSA S16-14(R2019) - Design of Steel Structures
    - CSA S304.1-14(R2019) - Design of Masonry Structures
    - CSA C22.1 - Canadian Electrical Code (CEC)

- National Research Council of Canada (NRCC)
    - National Building Code of Canada (NBC) 2025 Edition, including errata and revisions.
    - National Fire Code of Canada (NFC) 2025 Edition.
- IEEE
    - IEEE 142 (Green Book) – Grounding of industrial/commercial systems
    - IEEE 399 (Brown Book) – Power system analysis
    - IEEE 242 (Buff Book) – Protection and coordination
    - IEEE 3000 Series – Industrial power system design
    - IEEE C37 Series – Switchgear and protective devices

In the event of any conflict between the requirements of the referenced codes, standards and specifications, the following order of precedence, with one being the highest, will be applied as follows:

1. Regulations, Industry Codes and Standards
2. Project Documents and Reports
3. Project Drawings

5 Permitting and Regulatory

This section includes the following aspects:

- Review of applicable federal and provincial environmental regulations relevant to the Project, including environmental assessment requirements, environmental site assessment considerations, air quality legislation, and the Clean Electricity Regulations.
- Commentary on the applicability to the Project and anticipated permitting pathway.
- An overview of identified risks and assumptions that may impact cost or schedule.

5.1 Environmental Assessment Requirements and Process

5.1.1 Provincial

As an electrical power generation project, the Project will trigger environmental assessment (EA) requirements under the Newfoundland and Labrador *Environmental Protection Act* (NL EPA) and *Environmental Assessment Regulations*. Under Section 34 of the *Environmental Assessment Regulations*, electrical power generation projects with a capacity greater than 1 MW must be registered for an EA. Accordingly, the proposed replacement of the CTGs at the Greenhill (Grand Bank) and Wesleyville (New-Wes-Valley) sites will each require registration with the EA division. Additionally, permits and approvals under other potentially applicable legislation within the provincial and federal jurisdictions (i.e., those that may trigger other permits and/or approvals for the Project or influence the conduct of Project activities) may be required. Section 5.4 lists the permits and approvals likely required for the Project.

The NL EPA establishes a framework for the management of natural resources and the promotion of sustainable development. The associated EA process supports informed decision-making by identifying potential environmental effects and defining appropriate mitigation measures. Projects subject to the NL EPA and the *Environmental Assessment Regulations* are required to be registered with the EA Division of the Newfoundland and Labrador Department of Environment, Conservation and Climate Change (NLDECCC) for review.

An Environmental Registration Document is required to be prepared in accordance with the NL EPA and the guidance provided in *Environmental Assessment – A Guide to the Process* (NLDECCC 2025). The Project is required to follow the general EA guidance which is applicable to thermal generation and brownfield infrastructure replacement.

The approach to and level of information provided in the Environmental Registration Document can influence the provincial EA path for a project, including overall schedule and cost. Based on the scope of the Project, Stantec recommends preparation of a standard Registration Document.

A “standard” Registration Document is generally appropriate for projects that are relatively straightforward, have well-understood environmental effects, or are not anticipated to require a comprehensive assessment at the registration stage. A standard Registration Document focuses on meeting the requirements of the EA Division's guidance materials and can typically be prepared efficiently, allowing proponents to advance through the EA process in a timely manner.

An “enhanced” Registration Document is typically used for projects that may benefit from providing more detailed baseline information, effects assessment, and mitigation measures at the outset. This approach involves a greater level of effort and documentation to address potential regulatory questions early in the process and may increase the likelihood of the project being released from further assessment at the registration stage. Key considerations for EA preparation include existing site conditions, including potential soil and groundwater contamination associated with historical fuel storage and operations, particularly at Greenhill, as well as demolition and decommissioning activities and the replacement and upgrading of fuel storage infrastructure. Additional considerations include air emissions, noise effects on nearby residential receptors, hazardous materials handling, waste management, spill prevention, and interaction with identified environmentally sensitive features.

It is assumed no original field studies will be completed to support the preparation of the Environmental Registration, and the existing conditions of the environment would be described based on desktop information, publicly available data, and data requests from regulators such as the Atlantic Canada Conservation Data Centre (AC CDC). The Registration is required to include mitigation and environmental protection measures. Where appropriate, the Registration should include commitments to typical pre-construction surveys (e.g., pre-clearing nest survey, field verification of water crossings). A summary of Project-component interactions and mitigation measures should be described and summarized in a table format, as shown below. Some of the Project-component interactions may include, avifauna, bats, Species at Risk and Species of Conservation Concern, vegetation, amongst others.

Example: Table 1: Potential Resource Conflicts for Avifauna

Potential Resource Conflict	Project Phase			Mitigation Measures	Project Considerations
	C	O	D		
Land clearing activities will result in a direct loss or alteration of avifauna habitat, potentially including that of species at risk.	X	-	-	• Site footprint and disturbed areas will be limited to the extent practicable. • To the extent possible, construction related activities will occur outside of sensitive timing windows (e.g., breeding and nesting seasons).	The Project is located on or adjacent to a brownfield site.

Prior to initiating the Environmental Registration Document, early engagement with the EA Division is recommended to confirm regulatory expectations and submission requirements, present the Project scope and design basis, identify any site-specific sensitivities or data gaps, and align on the proposed level of assessment.

A typical standard Registration Document for this Project would include:

- Proponent information;
- Project overview and rationale;
- Regulatory framework;
- Detailed project description (including construction, operation, and decommissioning phases);
- Anticipated employment for construction and operation phases (including National Occupational Classification codes)
- Description of existing environmental conditions;
- Identification of potential environmental effects and mitigation measures;
- Management of hazardous materials, fuels, waste, and emissions;
- Consideration of alternatives;
- Indigenous and stakeholder engagement
- Capital cost and funding source; and
- Assessment summary and conclusions.

It is recommended, and has recently become an informal requirement, that a draft Environmental Registration Document be submitted to the EA Division in advance of the official submission. This allows government departments to review the document and provide comments, which can then be addressed and incorporated into the final Environmental Registration Document. This review typically takes two to three weeks to complete, with EA Division providing feedback to the proponent. Following the finalization and submission of the Environmental Registration, the EA Division undertakes a 45-day review period, during which the Environmental Registration Document is circulated to provincial and federal agencies, Indigenous groups, and the public. Upon completion of the review, the Minister of NLDECCC may: release the Project from EA (with or without conditions), require an Environmental Preview Report (EPR), require an Environmental Impact Statement (EIS), or reject the Project.

Where additional assessment is required, an EPR or EIS may be requested. An EPR is an assessment focused on key issues. It is requested when there is uncertainty about potential environmental effects or public concerns. Guidelines for an EPR are issued within 60 days of the Minister's decision. Depending on the requirements of an EPR, the preparation takes approximately 4-6 months. Following submission of the EPR, it undergoes a 45-day regulatory and public review, which may result in Information Requests or necessary revisions.

An EIS is a full assessment of the project and is requested if the Minister determines that there is potential for significant environmental effects or there is substantial public concern. It also involves the issuance of guidelines and appointment of an EA Committee which includes representatives of various government departments/agencies. Draft guidelines are issued within 120 days of the Minister's decision and are subject to a 40-day public review before final guidelines are released (in addition to the public, the proponent can provide feedback on the draft guidelines during this review period). Depending on the requirements of an EIS, the preparation takes approximately 8-10 months. Following submission of the EIS,

it is subject to a 70-day public and regulatory review period, which often results in at least one round of Information Requests or “deficiencies” which requires proponent response.

When a project is released from the EA process, at either the registration stage or after further assessment, it is typically subject to Conditions of Release. These are typically requirements for permits, management plans, and/or surveys that must be completed prior to the various project phases (i.e., prior to construction or prior to operation).

Given the Project’s scope as a replacement of existing generating infrastructure at established sites, it is anticipated that the Project may be released from the EA process following registration; however, the determination will depend on the outcome of regulatory review and supporting assessments.

5.1.2 Federal

The *Impact Assessment Act*, administered by the Impact Assessment Agency of Canada, establishes a federal process for assessing the environmental effects of designated projects identified in the *Physical Activities Regulations*, as well as certain projects proposed on federal lands or outside Canada. Based on the current Project scope, the undertaking does not meet the criteria for a designated project under the *Physical Activities Regulations*. The Project is also not anticipated to involve activities on federal lands or otherwise trigger federal impact assessment requirements. Accordingly, a federal impact assessment under the *Impact Assessment Act* is not expected to be required.

5.2 Air Quality and Noise

Air quality in NL is regulated by the *Air Pollution Control Regulations, 2022* under the NL EPA. The NL Air Quality Standards (NL AQS), prescribed under Schedule A of the *Air Pollution Control Regulations, 2022*, apply to ambient air contaminant concentrations and were originally established under NL EPA in 2004. The NL AQS values are shown in Table 5-1.

Table 5-1: Newfoundland and Labrador Air Quality Standards

Contaminant	Units	1-hour	3-hour	8-hour	24-hour	1 year
Air Quality Standards (2004)						
Ammonia	parts per billion (ppb)	-	-	-	144	-
Asbestos (greater than 5 microns in length)	fibres per cubic centimetre of air	-	-	-	0.04	-
Arsenic	micrograms per cubic metre (µg/m³)	-	-	-	0.3	-
Cadmium	µg/m³	-	-	-	2	-
Carbon monoxide	ppb	30,582	-	13,107	-	-
Copper	µg/m³	-	-	-	50	-

Contaminant	Units	1-hour	3-hour	8-hour	24-hour	1 year
Hydrogen sulphide	ppb	11	-	-	4	-
Lead	µg/m³	-	-	-	2	-
Mercury	µg/m³	-	-	-	2	-
Nickel	µg/m³	-	-	-	2	-
Nitrogen dioxide	ppb	213	-	-	106	53
Particulate matter < 2.5 microns	µg/m³	-	-	-	25	8.8
Particulate matter < 10 microns	µg/m³	-	-	-	50	-
Particulate matter (total)	µg/m³	-	-	-	120	60[B]
Polychlorinated biphenyls	µg/m³	-	-	-	0.15	0.035[A]
Polychlorinated dibenzo -p-dioxins & polychlorinated dibenzo furans (I-TEQ)	picograms (I-TEQ) per cubic metre of air	-	-	-	5[C]	-
Sulphur dioxide	ppb	344	229	-	115	23[A]
Vanadium	µg/m³	-	-	-	2	-
Zinc	µg/m³	-	-	-	120	-
Air Quality Standards for Air Zone Management						
Nitrogen dioxide (effective until December 31, 2024)	ppb	60[E]	-	-	-	17[A]
Nitrogen dioxide (effective January 1, 2025)	ppb	42[E]	-	-	-	12[A]
Ozone	ppb	82	-	44	-	-
Particulate matter < 2.5 microns	µg/m³	-	-	-	25[D]	8.8[A, D]
Sulphur dioxide (effective until December 31, 2024)	ppb	70[F]	-	-	-	5[A]
Sulphur dioxide (Effective January 1, 2025)	ppb	65[F]	-	-	-	4[A]
Notes:						

Contaminant	Units	1-hour	3-hour	8-hour	24-hour	1 year

[A] The arithmetic average over a single calendar year of all 1-hour average concentrations in the year.

[B] The geometric average over a single calendar year of all 1-hour average concentrations in the year.

[C] Under the Regulation, the International Total Equivalent Quotient (I-TEQ) concentration of polychlorinated dibenzodioxins and polychlorinated dibenzofurans is determined by multiplying the concentration of each congener listed in Column 1 of Table III by the corresponding toxicity factor set out in Column 2 of that item and by adding the products of them.

[D] At reference conditions, a dry gas temperature of 25°C and a gas pressure of 101.325 kilopascals

[E] The 3-year average of the annual 98th percentile of the NO_2 daily maximum 1 hour average concentrations.

[F] The 3-year average of the annual 99th percentile of the SO_2 daily maximum 1 hour average concentrations.

Source: *NL Air Pollution Control Regulations, 2022*

The applicable federal air quality criteria considered in the assessment are the Canadian Ambient Air Quality Standards (CAAQS). The CAAQS were established by the Canadian Council of Ministers of the Environment (CCME 2025, Table 5-2).

Table 5-2: Canadian Ambient Air Quality Standards

Air Contaminant	Averaging Period	µg/m³	
		2020–2024	2025+
Ozone (O_3)	8-hour [A]	122	118
Nitrogen Dioxide (NO_2)	1-hour [B]	113	79
	1-year [C]	32	23
Sulphur Dioxide (SO_2)	1-hour [D]	183	170
	1-year [E]	13	10
Fine Particulate Matter ($PM_{2.5}$)	24-hour [F]	27	23 (2030)
	1-year [G]	8.8	8.0 (2030)

Notes:

[A] The 3-year average of the annual 4th highest of the daily maximum 8-hour average ozone concentrations

[B] The 3-year average of the annual 98th percentile of the daily maximum 1-hour average concentrations

[C] The average over a single calendar year of all 1-hour average concentrations

[D] The 3-year average of the annual 99th percentile of the SO_2 daily maximum 1-hour average concentrations

[E] The average over a single calendar year of all 1-hour average SO_2 concentrations

[F] The 3-year average of the annual 98th percentile of the daily 24-hour average concentrations

[G] The 3-year average of the annual average of the daily 24-hour average concentrations

Source: CCME (2025)

It is the mandate of the Industrial Compliance Section of the Government of NL to prevent the degradation of the environment by industrial operations and ensure their compliance with the provincial regulations (Government of NL 2023). Industrial activities with releases of air contaminants to the atmosphere may be required to obtain a Certificate of Approval from the NLDECCC.

Certificates of Approval typically contain requirements for stack testing and annual reporting of emissions. In some cases, approvals are issued subject to results from ambient monitoring campaigns which may lead to more stringent conditions of approval related to stack testing requirements and frequency, or air contaminant dispersion modelling. It is our understanding the existing facilities have never been required to obtain a Certificate of Approval. An email was sent to Dexter Pittman, Manager of Environmental Compliance, Pollution Prevention Division (NLDECCC) to inquire on whether replacement units at these sites would be anticipated to have stack testing, dispersion modelling requirements and the response was that it would not be required of replacement units at this time. The following discussion of potential regulatory requirements is provided for informational purposes but is not expected to be required for the new units based on NLDECCC response.

The Government of NL has also published guidance documents to help proponents fulfill the requirements of the Air Pollution Control Regulations, 2022. The Determination of Compliance with the Ambient Air Quality Standards Guide (GD-PPD-009.4) outlines the types of facilities that will require a determination of compliance to the ambient air quality standards, and what steps are required to demonstrate compliance (NLDEC 2012). This guideline outlines the source testing, air contaminant dispersion modelling, and ambient monitoring requirements for different emission source types. A summary of the guide for source testing is shown in Table 5-3.

Table 5-3: Summary of Compliance Determination Procedures for NL Certificates of Approval

Emission Source Type	Definition	Source Testing and Dispersion model Frequency
I	• require a minimum annual residual fuel oil consumption of 2,000,000 litres; or • require a minimum annual distillate fuel oil consumption of 15,000,000 litres; or • emit a minimum of 20 tonnes of total particulate matter from a stack or a series of stacks annually; or • require a minimum of 25 MW of electrical power on a continuous basis for use in an industrial process where the process has a resulting emission of an air contaminant to the atmosphere.	• Once in first 6 months of operation • Once in last 6 months of first two years of operation • Once every 4 years if air contaminant dispersion modelling shows compliance with Ambient Air Quality Standards for all contaminants • Once every 2 years if air contaminant dispersion modelling shows non-compliance with Ambient Air

		Quality Standards for any contaminant
II	require less than 2,000,000 litres of residual fuel oil consumption annually	Once within first 6 months of operation, then once every 5 years.
III	have a minimum total particulate matter emission of 20 tonnes annually, where the emission is not from a stack or a series of stacks	None
IV	diesel generating facilities with a total installed capacity of 100 KW of power and operating for at least 500 hours annually.	None
V	have an emission from a source that is not categorized as either a Type I, Type II, Type III or Type IV emission source, but which may have an emission that poses an environmental concern.	As outlined in the certificate of approval

Source: NLDEC 2012

Stantec estimated particulate emissions to be much less than 20 tonnes for each facility, assuming 300 hours of operation per year (for each unit) and the fuel consumption would be distillate fuel oil (diesel) at less than 2,000,000 L per year, which classifies the facilities as having Type V emission sources. Although the guidance document (NLDEC 2012); allows for inclusion of emission testing and dispersion modelling for Type V sources, it is not commonly done and would be unusual for this type of facility. (i.e. small diesel facility).

The *Air Pollution Control Regulations* have other requirements for new sources including use of Good Engineering Stack Height, Best Available Control Technology (BACT), infrastructure to allow emissions testing and requirements for above ground fuel storage. These items may be exempted due to the low operating hours of the facilities; however, it is recommended that the requirements be reviewed with the NL Government to confirm their expectations for these Projects. Based on estimates of particulate matter and sulphur dioxide for each site, assuming 300 operating hours annually, neither would exceed the amount for Good Engineering Stack Height.

It is anticipated that continuous emissions monitoring systems will not be required based on the email received from Dexter Pittman, NLDECCC, however that should be confirmed through further discussion with the Pollution Control division. Mr. Pittman also indicated that emissions testing and dispersion modelling would not be required for the units and that they would be classified as Type V sources (pers. Comm. NLDECCC. 2026)

The potentially relevant excerpt from the Newfoundland and Labrador Regulation 11/22 *Air Pollution Control Regulations, 2022* under the Environmental Protection Act (O.C. 2022-072) is reproduced below verbatim, for reference:

Non-portable aboveground storage tanks

14. *(1) All non-portable aboveground storage tanks with a volume greater than 4 m^3 and storing a volatile organic liquid with a vapour pressure greater than 10 kPa at 21.1 ° Celsius shall comply with the provisions of the CCME guidelines "Environmental Guidelines for Controlling Emissions of*

> *Volatile Organic Compounds from Aboveground Storage Tanks, PN 1180" including any amendments to those guidelines.*
> *(2) The owner or operator of a facility to which subsection (1) applies shall, in respect of each calendar year, provide all records required for reporting under Part 7 of the guidelines referred to in subsection (1), by February 28 of the following calendar year.*

Noise is not formally regulated in Newfoundland & Labrador; however, some municipalities have noise by-laws. Typically, noise is addressed in an Environmental Registration for this type of project and would at minimum discuss whether noise is expected to change notably from the current operations. It is expected that since both sites are currently operating power generating units of a similar size, the noise levels will not change notably. As Wesleyville unit is a good distance from the nearest residences (over 1 km), there would not be expected to be a noticeable change at those residential locations. For Greenhill, the new units will be similar distance to the nearest residence, approximately 140 m. Noise at this distance would be noticeable and may warrant a quantitative evaluation. As the units will operate infrequently, and be similar to the current situation, it is not likely to cause unacceptable annoyance. This assumes no noise complaints are received for the existing operation.

5.3 Greenhouse Gases (GHG)

Based on 300 operating hours annually, GHG emissions from both sites are estimated to be below the thresholds that would trigger provincial or federal GHG reporting or regulatory requirements (both well below 10,000 tonnes carbon dioxide equivalent, CO_2e, annually). An estimate of annual GHG emissions would typically be included in the Environmental Registration and reviewed and confirmed by the NLDECCC. Details of the provincial and federal programs are provided below for informational purposes. As both the province and the federal government have targets to reach net zero GHG by 2050, it can be assumed that new actions to target smaller emitters will be implemented in the future, however, they may still exempt peaking units/emergency units or require GHG offsetting for those sources (where credits would be purchased to offset emissions required during an emergency condition).

The NL government requires industrial facilities to report GHG emissions under the NL *Management of Greenhouse Gas Act* (MGGA) and its regulations if the facility releases 15,000 tonnes (t) of carbon dioxide equivalent (CO_2e) or more per year from onsite GHG emissions sources during operation. Onsite GHG emissions refer to those generated by sources or activities that are controlled/owned by a reporting entity or project at the site and does not include on-road vehicles (NLDECCC. 2017).

If a facility is expected to emit 15,000 t CO_2e or more per year from onsite GHG emissions sources during operation, it is subject to best available control technology (BACT) requirements outlined in the *Management of Greenhouse Gas Regulations* (MGGR).

The MGGR states that targets established pursuant to section 5 of the MGGA do not apply to a facility during its construction and pre-production stages.

The province of NL has committed to reducing GHG emissions and supporting the transition to a low carbon economy in NL with the following reduction targets:

- 30% reduction in provincial GHG emissions below 2005 levels by 2030

- 60% by 2040
- Net-zero emissions by 2050 (Government of NL. 2025)

Federally, industrial facilities that emit 10,000 t CO_2e or more per year (during operation) are required to report GHG emissions to Environment and Climate Change Canada's (ECCC) Greenhouse Gas Reporting Program under the *Canadian Environment Protection Act*. The federal government recently developed an Emissions Reduction Plan under the *Canadian Net-Zero Emissions Accountability Act*, which aims to reduce emissions across Canada by 40–45% below 2005 levels by 2030. The federal government has committed to achieving net-zero emissions by 2050 (Government of Canada. 2022).

There are currently no legislative drivers applicable to emissions reductions for these generating facilities due to their small annual GHG emissions, putting them below the current thresholds for compliance obligations, however it can be anticipated that there will be prior to 2050 if the Net-Zero by 2050 plans proceed to unfold.

5.3.1 Clean Electricity Regulations

The Clean Electricity Regulations (CER) pertain to GHG emissions from fossil fuel-based electricity generation. The CER only applies to generating units that are above 25 MW and connected to an "electricity system" directly or indirectly that is subject to the standards of the North American Electric Reliability Corporation (NERC). NERC standards are enforceable for bulk electricity grids in the continental United States and the following Canadian provinces: British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Québec, Nova Scotia and New Brunswick. Notably, Prince Edward Island, Newfoundland and Labrador, Yukon, Northwest Territories and Nunavut are not subject to NERC standards. However, as the CER indicates direct or indirect connections to a NERC standards grid, the CER may apply for the facilities. In this case, Greenhill would exceed the 25 MW threshold and fall under the CER regulated facilities. Based on planned operating hours, the Greenhill units are not expected to exceed the allowable emissions under the CER from 2035 to 2050. After 2050, allowable emissions are zero however there are still allowances for emergency situations and offsetting emissions.

5.4 Applicable Environmental Permits

Table 5-4 provides a list of environmental permits, approvals, and authorizations that may be required in support of the Project. The table provides a summary of the permitting requirements for the Project, including timelines, applicable fees, and the overall permitting schedule. This list is considered preliminary, based on the Project description, and would be further refined as Project planning proceeds.

Table 5-4: List of Potentially Applicable Permits, Approvals, and Authorizations for the Project

Permit / Approval / Authorization and Decision-Maker	Legislation / Regulation	Permit Requirements	Timing and Permit Fee	EA Phase
Provincial				

Permit / Approval / Authorization and Decision-Maker	Legislation / Regulation	Permit Requirements	Timing and Permit Fee	EA Phase
Release from EA Process NLDECCC – Minister	*Environmental Protection Act*	As described in Section 5.1.1.	As described in Section 5.1.1. A registration fee of $400 (plus HST) is required upon submission of the Environmental Registration Document, with a separate registration required for each site. Additional fees apply if further assessment (i.e., EPR or EIS) is required.	EA
Fuel Storage Tank Registration NL Department of Government Services	*Environmental Protection Act, Storage and Handling of Gasoline and Associated Products Regulations*	Registration is required for underground and above ground storage facilities for the storage and handling of gasoline and associated products. For new facilities, a permit is also required for flammable and combustible liquid storage and dispensing (above or below ground) and for bulk storage (above ground only) under the *Fire Prevention Act.*	Application should be filed in advance of installing the fuel tank (i.e., in advance of construction). No fees required for registration unless additional permits are required under the *Fire Prevention Act.* Fees outlined in the Building Plan Approval, Commercial would then apply.	Pre-construction
Used Oil Storage Approval NL Department of Government Services	*Environmental Protection Act, Used Oil and Used Glycol Control Regulations*	Approval is required where greater than 205 litres of used oil or used glycol is to be stored in one or more containers. Registration is also required for an oil separator.	Application should be filed prior to construction. Fees to be determined in consultation with regulator.	Pre-construction
Certificate of Approval NLDECCC – Industrial Compliance Section of Pollution Prevention Division	*Environmental Protection Act, Air Pollution Control Regulations*	The proposed combustion turbine generators at the Greenhill and Wesleyville sites will generate air emissions during operation and therefore may require a Certificate of Approval for construction and operation.	Recommend consultation with regulator to determine requirement for a C of A. If applicable, application should be filed prior to construction. Fees in accordance with the Industrial Approval Fees Policy.	Pre-construction

Permit / Approval / Authorization and Decision-Maker	Legislation / Regulation	Permit Requirements	Timing and Permit Fee	EA Phase
Permit to Cut NL Department of Forestry, Agriculture and Lands (NLDFAL) – Forestry Division	*Forestry Act, Cutting of Timber Regulations*	A cutting permit may be required for the removal of timber associated with vegetation clearing, particularly where activities occur within or adjacent to forested areas.	Application should be filed in advance of construction. Permit fees can be up to $50.	Pre-construction
Operating Permit NLDFAL – Forestry Division	*Forestry Act, Forest Fire Regulations*	A permit may be required to authorize construction or industrial activities during the forest fire season for works involving vegetation clearing or operations in proximity to forested areas.	Application should be filed in advance of construction. No fees required for permit.	Pre-construction
Septic System Approval NL Department of Government Services	*Health and Community Services Act, Water Resources Act*	If the existing septic systems at either site require upgrading or replacement, a Septic System Approval may be required.	Application should be filed in advance of construction. No fee required if less than 4546 L per day.	Pre-construction
Permit for Constructing a Non-Domestic Well NLDECCC – Water Resources Management Division (WRMD)	*Water Resources Act*	If the existing drilled well at the Wesleyville site requires upgrading or replacement, a Permit for Constructing a Non-Domestic Well may be required.	Application should be filed in advance of construction. Upon processing the application, WRMD will advise the proponent on the requirement for pumping tests and how long these tests need to run. A non-refundable fee of $400.00 + HST must accompany the permit application.	Pre-construction
Storage and Handling of Gasoline and Associated Products Regulations	*Environmental Protection Act*	The Project is required to comply with the *Storage and Handling of Gasoline and Associated Products Regulations* depending on the final project design.	N/A	Pre-construction

Permit / Approval / Authorization and Decision-Maker	Legislation / Regulation	Permit Requirements	Timing and Permit Fee	EA Phase
Federal				
Migratory Bird Permit Nest Removal Permit ECCC – Canadian Wildlife Service	*Migratory Birds Convention Act, Migratory Birds Regulations, 2022*	A migratory bird permit and a nest removal permit may be required if interactions with migratory birds and nests are anticipated during Project activities.	Application should be filed in advance of construction. Fees determined by ECCC at time of application.	Pre-construction
Municipal				
Development Permit Town of Grand Bank	*Grand Bank Development Regulations*	A Development Permit may be required for the Greenhill site.	Application should be filed in advance of construction. Fees would be dependent on the construction cost.	Pre-construction
Development Permit Town of New-Wes-Valley	*New-Wes-Valley Development Regulations*	A Development Permit may be required for the Wesleyville site.	Application should be filed in advance of construction. Fees determined by the Town of New-Wes-Valley at time of application.	Pre-construction

5.5 Risks and Assumptions

The following risks and assumptions have been identified that may influence the Project schedule and/or cost during the assessment and permitting phase.

5.5.1 Environmental Assessment Pathway

It is anticipated that the Project may be released from the EA process following registration, based on its scope as a replacement of existing CTG infrastructure at established sites, with limited expansion beyond the existing footprint.

A key risk to the Project schedule is the potential for the Minister to require further assessment in the form of an EPR or EIS as discussed in Section 5.1.1. While this outcome is considered unlikely given the brownfield nature of the Project and absence of major new development, it would result in an extended EA timeline and a corresponding increase in Project costs.

An EPR has the potential to extend the regulatory process by approximately 4 to 6 months and introduce additional requirements, and costs, related to technical studies, documentation, and regulatory coordination. An EIS would represent a more substantial escalation, potentially extending timelines by approximately 12 to 24 months or longer, and may require comprehensive baseline studies, detailed environmental assessment, and iterative regulatory review and information requests. This would result in a

notable increase in Project costs, including technical studies, documentation, stakeholder engagement, and extended project management.

5.5.1.1 Cost Estimate

The following cost estimate provides a planning-level budget for completion of a standard Environmental Registration Document and EPR for each of the two proposed Project sites. The estimate is based on Stantec's experience with similar projects in the province, current EA Division requirements, and the assumptions outlined below. Actual costs may vary depending on project complexity, regulator feedback, technical study requirements, and the level of assessment required.

Table 5-5: Environmental Assessment Cost Estimate for the Project

Assessment Component	Cost Per Site (CAD)	Cost for Two Sites (CAD)
Environmental Registration		
EA Division Fees	$400	$800
Consulting Fees	$40,000 – $50,000	$70,000 – $100,000
Noise Modelling	$15,000	$25,000
Environmental Preview Report		
EA Division Fees	$10,000	$20,000
Consulting Fees	$80,000 – $150,000	$160,000 – $300,000
Subtotal (before HST)	**$145,400 – $225,400**	**$275,800 – $445,800**

Assumptions and Caveats:

- The cost estimates assume a similar level of effort for both Environmental Registrations and both potential EPRs. It is anticipated that development of the Registration for the first site will create templates and establish project-specific information (e.g., details on the units being installed) that can be applied to the document for the second site, potentially reducing the level of effort and associated consulting costs for the second site.
- The estimate assumes that each site will be assessed through a standard Environmental Registration process in accordance with the NL EPA and the guidance provided in *Environmental Assessment – A Guide to the Process* (NLDECCC 2025). Costs associated with an enhanced Environmental Registration (i.e., including a fulsome assessment of potential environmental effects) have not been included and would be subject to additional fees.
- It is assumed that each of the two Projects will have an estimated capital cost greater than $5 million; therefore, the applicable EA Division EPR fee of $10,000 has been included in the estimate.
- It is assumed that a federal assessment under the *Impact Assessment Act* is not required.
- It is assumed that BACT assessment and air dispersion modelling will not be required for either site.
- Noise modelling has been budgeted for both sites as a conservative approach. Depending on project design and regulatory requirements, detailed noise modelling may only be required for the Greenhill Site, which has a close noise-sensitive receptor (residence adjacent to the existing site).

Given the similarity of the proposed equipment between sites, if compliance can be demonstrated at the Greenhill Site, detailed modelling for the New-Wes-Valley site may not be required.

- Support for regulatory engagement related to the preparation and review of the Environmental Registration and EPR is included in this estimate and assumes consultant participation in up to four regulatory meetings with NP.
- Support for public and Indigenous engagement is not included, and it is assumed that NP will lead these activities. Should consultant support for public and/or Indigenous engagement be requested, the estimate would increase accordingly.
- Recently, EA Division has requested the opportunity to review a draft Environmental Registration Document prior to formal submission in order to provide high-level feedback. The estimated consultant costs include a token allowance to revise and update the draft Environmental Registration Document in response to regulator comments received during this review.
- Subsequent assessments, permitting/approval requirements, and post-release conditions (e.g., management plans, monitoring programs, or follow-up studies required by regulators) are not included in this estimate.
- The estimated cost for the Environmental Registration includes fees for acquiring data from the AC CDC. It is assumed that other required data will be publicly available (or available upon request) from regulators.
- It is assumed no original field studies will be completed to support the preparation of the Environmental Registration or EPR. If required by regulators, the estimate would increase accordingly.
- Estimates provided in Table 5-5 do not include HST.

5.5.2 Air Quality and Noise Assessment

Based on preliminary correspondence with Pollution Control Division, it was indicated that no source testing, continuous emissions monitoring or dispersion modelling would be required however it is recommended that a formal meeting be set to review the project details with this group and confirm with them their expectations. This group of NLDECC would also be responsible to request a noise assessment if they thought it was warranted. As noted earlier, if there have not been previous noise concerns at the sites, it is not expected to be a requirement to do a quantitative noise assessment.

5.5.3 Vegetation Clearing and Field Survey Requirements

The Project is expected to be largely confined to previously disturbed areas at both the Greenhill and Wesleyville sites. Where minor extensions beyond the existing footprint are required, it is anticipated that the Wesleyville site will require approximately 1,835 m² for clearing and grubbing, while the Greenhill site will require approximately 7,330 m². Given the relatively small clearing requirements, effects are anticipated to be limited, and the need for extensive environmental field surveys is considered unlikely.

A potential risk arises where Project activities extend into adjacent forested or previously undisturbed areas, which may trigger the need for additional environmental baseline information or field surveys (e.g., vegetation, wildlife, or species at risk assessments). This may introduce schedule constraints, particularly

where seasonal survey windows apply, and may result in additional costs associated with field programs, technical studies, and supporting documentation required for regulatory review.

Measures to reduce the potential for additional study requirements should be incorporated into Project planning and execution. These measures could include, where practicable, confining construction activities to previously disturbed areas and implementing standard environmental protection practices. Vegetation clearing should be scheduled, to the extent feasible, to avoid sensitive wildlife periods, including the migratory bird nesting season (approximately mid-April to mid-August; ECCC 2025).

To support the EA process and reduce uncertainty, an AC CDC request should be completed and included in the Environmental Registration Document. This will identify known occurrences of species at risk or sensitive habitats within or near the Project area. Early identification of these features will help confirm the low likelihood of constraints, support the assessment of potential environmental effects, and reduce the risk of additional information requests or field survey requirements during regulatory review.

5.5.4 Environmental Protection Plan

It is assumed that Project activities will be carried out in accordance with NP's existing Environmental Protection Plan and associated environmental management programs. This includes implementation of standard mitigation measures and contingency plans.

5.6 Site Contamination Considerations

5.6.1 Greenhill Site

Infrastructure at the Greenhill site includes fuel aboveground storage tanks (ASTs), an aboveground pipeline to transport fuel, a fuel pumping station, a propane AST, a power generating building, and an electrical substation with electrical transformers, utility structures, and utility lines.

Three 100,000 litre (L) capacity fuel ASTs provide fuel to the on-site power generating building via an aboveground pipeline. Two of the ASTs were installed in 2002, and one AST was installed in 2014. The power generating building was constructed in the 1970s.

It is understood that the existing ASTs and the power generating buildings will be decommissioned and removed from the Greenhill site and replaced with new infrastructure. It is Stantec's current understanding that no environmental site assessments (ESAs) or hazardous building material assessments (HBMAs) have been completed at the Greenhill site.

Due to the current and historic use and storage of fuel, lubricants, and insulating oils at the Greenhill site there is the potential for the presence of contaminants of potential concern (COPCs) including but not limited to petroleum hydrocarbons (PHCs), polychlorinated biphenyls (PCBs), metals, polycyclic aromatic hydrocarbons (PAHs), and glycols in soil and groundwater.

Due to the age of the construction of the power generating building the associated infrastructure there is the potential for the presence of hazardous building materials including but not limited to asbestos containing

materials, lead-based paints, mercury-based paints, PCB-containing materials, and ozone-depleting substances.

It is recommended that a Phase I and Phase II ESA be completed at the Greenhill site to assess the presence/absence and concentrations of COPCs in soil and groundwater and a HBMA be completed at the site to assess the presence/absence and concentrations of hazardous building materials at the site. The assessments should be undertaken using a phased approach, with the scope of the Phase II ESA informed by the findings of the Phase I ESA. Although not a regulatory requirement, this approach represents sound due diligence and provides a cost- and schedule-efficient method for developing an effective construction phase management plan.

5.6.2 Wesleyville Site

Infrastructure at the Wesleyville site includes fuel ASTs, an above ground pipeline for fuel, a fuel pumping station, a propane AST, a power generating building, and an electrical substation with electrical transformers, utility structures, and utility lines.

Two 75,000 L capacity ASTs provide fuel to the on-site power generating building via an aboveground pipeline. The ages of the ASTs are 2003. The power generating building was constructed at the Wesleyville site in 2003.

It is understood by Stantec that the ASTs will be decommissioned and removed from the Wesleyville site and that the current power generating building will be renovated. It is Stantec's current understanding that no ESAs or HBMAs have been completed at the Wesleyville site.

Due to the current and historic use and storage of fuel, lubricants, and insulating oils at the Wesleyville site there is the potential for the presence of COPCs including but not limited to PHCs, PCBs, metals, PAHs, and glycols in soil and groundwater at the Wesleyville site.

Due to the age of the construction of the power generating building the associated infrastructure there is the potential for the presence of hazardous building materials including but not limited to asbestos containing materials, lead-based paints, mercury-based paints, PCB containing materials, and ozone-depleting substances at the Wesleyville site.

It is recommended that a Phase I and Phase II ESA be completed at the Wesleyville site to assess the presence/absence and concentrations of COPCs in soil and groundwater and a HBMA be completed at the site to assess the presence/absence and concentrations of hazardous building materials at the site. The assessments should be undertaken using a phased approach, with the scope of the Phase II ESA informed by the findings of the Phase I ESA. Although not a regulatory requirement, this approach represents sound due diligence and provides a cost- and schedule-efficient method for developing an effective construction phase management plan.

5.6.3 ESA Regulatory Framework

The following regulatory framework is applicable to the ESA work proposed for the Greenhill and Wesleyville sites.

- Decommissioning, upgrades, and installation of fuel storage systems shall comply with the NL Department of Environment and Climate Change (NLDECC) *Storage and Handling of Gasoline and Associated Products Regulations (dated May 2003).*
- Management of contaminated sites shall comply with *NLDEEC policy directive PPD05-01 Guidance Document for the Management of Impacted Sites, Version 2.0 (dated September 2005; updated January 2014)*. The purpose of this guidance document is to provide a clear process for the management of impacted sites in NL that result in the satisfactory resolution of environmental contamination, which may present an unacceptable risk to human health and ecological receptors. The NLDECC guidance document recommends the use of the *Atlantic RBCA (Risk-Based Corrective Action) Version 4.0 User Guidance Document (July 2021, updated 2022)* for ESA and remediation activities.

5.6.4 Phased Environmental Site Assessments Considerations and Cost

Due to the current and historic use of petroleum products at the sites, including fuel, lubricating, and insulating oils, the potential for environmental contamination is present. As such, a phased ESA approach is appropriate for the sites. Phased ESAs are an approach to investigate potential environmental contamination at a site and identify, assess, and manage risks associated with potential contamination. ESAs are completed in a phased process, with each phase building upon the findings of the previous phases. Depending on the presence or potential presence of contamination the ESA process could include a Phase I ESA (the identification stage), a Phase II ESA (the assessment stage) and a Phase III ESA (the delineation stage). In some instances, further phases such as a Phase IV or Supplemental ESA are required to assess the extent and severity of contamination.

Stantec's cost estimate to complete the scope of work for a Phase I ESA per site is approximately **$7,000 (excluding applicable taxes)** each. In accordance with Public Services and Procurement Canada (PSPC) Cost Estimate Definitions, this estimate represents a preliminary, indicative assessment of cost based on limited project definition.

Stantec's cost estimate to complete the scope of work for a Phase II ESA per site is approximately **$50,000 (excluding applicable taxes)** each. In accordance with PSPC Cost Estimate Definitions, this estimate represents a preliminary, indicative assessment of cost based on limited project definition.

If environmental investigations confirm the presence of contamination in soil and/or groundwater at the sites soil and groundwater will require management in compliance with *NLDEEC policy directive PPD05-01 Guidance Document for the Management of Impacted Sites, Version 2.0 (dated September 2005; updated January 2014.* If future construction requires excavation and off-site soil disposal, excavated soils may need to be treated as impacted material and disposed of at an approved contaminated soil facility, at additional cost. If dewatering is required during excavation or construction, the groundwater may require treatment and regulatory approval prior to discharge, or off-site disposal using licensed contractors. These conditions introduce additional cost, regulatory oversight, and schedule considerations for any redevelopment involving ground disturbance.

5.6.5 Hazardous Building Materials Assessments Considerations and Cost

Based on the age and use of the buildings and associated infrastructure at the sites, hazardous building materials are potentially present and a HBMA is recommended for the sites prior to demolition or renovation work. During a HBMA samples of building materials including but not limited to insulation, paint, caulking, adhesives, grout, and roofing materials are collected and analysed for hazardous building materials. Visual observations of other hazardous building materials including but not limited to mercury containing materials, PCB containing materials, refrigerants, and radioactive materials are also made.

Stantec's cost estimate to complete the scope of work for a HBMA per site is approximately **$40,000 (excluding applicable taxes)** each. In accordance with PSPC Cost Estimate Definitions, this estimate represents a preliminary, indicative assessment of cost based on limited project definition.

If hazardous building materials are identified during the HBMA, they must be managed, removed, and properly disposed of during demolition and/or renovation work. The requirements could increase project costs and schedules and should be considered during the planning stage for demolition and renovation work.

6 Design Basis

6.1 Mechanical

6.1.1 Building Utilities

The Greenhill site requires a new building for switchgear, control room, washroom, service bay, mechanical room, and storage / maintenance. Mechanical components required for this building include HVAC, potable water, plumbing and kitchen / washroom fixtures.

The Wesleyville site contains an existing building that will be re-used. Once the existing turbine and generator are removed from the building, the turbine and generator hall will be re-used for switchgear, an electrical room, and a storage / maintenance room. NP confirmed the existing mechanical utilities in the Wesleyville building will be maintained and no mechanical upgrades are required, with the exception of a potable water storage tank. Due to issues obtaining water at the Wesleyville site, two potable water tanks and one pump will be included in the room which currently contains the fuel supply pumps and filters to the existing combustion turbine. We have assumed the tanks will be standard 1,000 L (275 gal) totes, stacked on top of one another for a total of 2,000 L (550 gal) of potable water storage, see Section 6.5.5 for storage capacity basis. The mechanical room single door will need to be updated to a double door for access into the room.

Preliminary building general arrangement drawings and site layout drawings have been provided for both sites.

Both sites include a fuel pumphouse for equipment described in the following Combustion Turbine section. The pumphouses will contain electric unit heaters and an exhaust fan.

6.1.2 Combustion Turbine

The Greenhill site design basis and cost estimate are based on the supply of two 15 MW combustion turbines. The Wesleyville site design basis and cost estimate are based on the supply of one 15 MW combustion turbine. The combustion turbines will be located outdoors. The combustion turbines will be liquid fueled, modular, and complete with a cold weather enclosure package. Also included with the turbine supply is the air intake system, internal cooling / ventilation / fire protection system, high pressure VFD driven fuel pump, high pressure fuel filter, fuel monitoring skid, fuel coalescer skid, lube oil filter, lube oil cooler, and a lube oil immersion heater. NP has requested that a dry emissions system using specialized fuel injectors, regulated air flow, and optimized flame temperature to reduce pollution formation be included to limit the formation of nitrous oxides, carbon monoxide, and unburned hydrocarbons.

An exhaust stack roughly 38ft tall and 76-inch exit diameter is required for each combustion turbine. Exhaust stacks will be complete with access hatch, drain, and bottom plate heat tracing to prevent snow build-up. The exhaust stack will be supplied with necessary expansion joint and horizontal duct / breaching. The exhaust stack will be shipped in roughly 4 sections and assembled in the field.

The Greenhill and Wesleyville sites will both include a 1.5 MW black start generator. They will operate on diesel fuel and will contain a sub-base fuel tank.

Process flow diagrams have been created for the two sites to display the diesel fuel flow path from truck unloading to the new fuel tanks, and from the fuel tanks to the combustion turbines. The Greenhill site will contain independent fuel systems from the tanks to the combustion turbines for redundancy. Fuel forwarding pumps will be used to provide fuel from the fuel tanks to the combustion turbines. The fuel forwarding pumps will be 5 HP and will push fuel through the fuel monitoring and fuel coalescing skids, which contain 10 micron and 3-micron duplex filters, respectively. The fuel will then go through an approximately 66 kW electric fuel heater to maintain the fuel at a minimum temperature of 10°F above the fuel cloud point temperature and below 140°F. From there, approximately 75 lpm of fuel is fed to the combustion turbine, when in operation, and the remaining fuel is recirculated back to the fuel forwarding building. The recirculation will keep the fuel in motion and heated and will keep the pumps operating above their minimum required flow. Also branching off the supply from the fuel tanks are the black-start generator fuel pumps. A common fuel handling pumphouse will be used at both sites, as shown on the preliminary site layout drawings, for the fuel truck unloading pumps, fuel forwarding pumps, black start genset fuel pumps, fuel monitoring / filtering skids, and the fuel heater. At the combustion turbines, there is a VFD driven pump with a 25 HP motor to increase the fuel pressure to 1,000 psig and a 25-micron high pressure simplex fuel filter. The fuel system design also includes hook-ups for a portable fuel conditioning trailer that can be shared between the two sites to periodically remove rust, bacteria clusters, water, and solid particulates to 1 micron from the fuel. Fuel piping will be welded carbon steel, heat traced and insulated. Fuel piping and valving is included in the estimate as piping contractor supplied and installed.

The combustion turbine supply will include the lube oil cooler, that will be mounted off the combustion turbine air intake system. A steel platform, stairs, access, etc. are required. Each site will contain a waste oil tank, similar to the existing tank at Greenhill. Tanks will be 3,000 L, fiberglass, double walled and located underground. Piping and valving from the combustion turbines to the waste oil tanks is included in the estimate as piping contractor supplied and installed.

Each site will have one compressed air system. At Greenhill, it will be shared between the two combustion turbines. Compressed air is required for combustion turbine start-up (atomizing air) and pneumatic valves, such as vendor supplied shut-off valves. The compressed air system will consist of an air compressor, wet air receiver, desiccant dryer, and a dry air receiver. The wet air receiver would be 240 gallons, and the dry air receiver would be 1,200 gallons. The dry air receiver has been sized to handle the full start-up atomizing air flow requirement. At Greenhill, the compressed air equipment would be located in the mechanical room shown on the proposed building layout drawing. At Wesleyville, the room that currently contains the fuel supply pumps and filters to the existing combustion turbine would be repurposed to contain the compressed air equipment. Interconnecting compressed air piping and valving between compressed air equipment and piping and valving from the compressed air equipment to the combustion turbines is included in the estimate as piping contractor supplied and installed.

The combustion turbine dry emissions system requires a de-ionized water purge system. The flow rate is approximately 30 lpm and is required during fuel transfers, shutdowns, and fail to start / shutdown events. It has been assumed that a standard tote (1,000 litres) would be located at each facility to store the de-ionized water, along with a small pump. The de-ionized water can either be trucked in and used to fill a

permanent tote, or new de-ionized water totes can be delivered to site to replace empty totes. At Greenhill, the de-ionized water tote would be located in the mechanical room shown on the proposed building layout drawing. At Wesleyville, the de-ionized water tank will be included in the compressed air equipment room, which currently contains the fuel supply pumps and filters to the existing combustion turbine. Water piping and valving is included in the estimate as piping contractor supplied and installed.

6.1.3 Fuel Tanks

There will be new fuel storage systems provided at both sites to provide reliable storage, and supply to the turbines. These systems will also be designed to meet recently updated environmental requirements for petroleum storage, and supply to oil burning equipment. For the Greenhill site there will be four (4) new 100,000 L ULC S601 vertical tanks installed and placed inside a new secondary containment berm that is lined with ULC rated high density polyethylene (HDPE) geomembrane and sized as per National Fire Code (NFC) requirements. The tanks shall be placed on concrete foundations inside the berm with double walled, vacuum monitored floors. Tanks shall be equipped with fail-safe motor operated valves (MOVs), radar level transmitters, high-level switches and alarms, and visual level indicators to meet API 2350 over-fill protection requirements. The tanks shall be installed to allow any unit to feed any turbine or engine. The intent is for all tanks to maintain the same consistent level with open bottom connections when in use to prevent overfill of a single unit from misdirected flow. This setup will also allow any tank to come out of service for inspection and maintenance without an outage to the turbines.

There will also be a new offloading station added at the site for bulk fuel delivery complete with concrete pad, spill containment enclosure, and duplex 7.5 HP self-priming offload pumps to allow delivery from full size tanker trucks, including B-trains. Stair access to the tank roofs with railings and platforms between tanks shall allow easy and safe manual level verification for fuel delivery.

Fuel supply from the tanks shall be provided by new 5HP rotary gear pumps to the filtration and heater skids noted above. Recirculation of fuel back to the tanks shall be controlled via back pressure regulators. Anti-syphon protection to the system shall be provided by supply spring return MOVs on the tanks that will be fail-safe normally closed when the turbines are offline.

The new system for the Wesleyville site shall be the same as noted above for Greenhill, except that there will be two (2) new 100,000 L vertical tanks placed on the site for the one new turbine. The site will also the same off-loading pad setup, tank instrumentation and accessories, and supply systems. The tanks will be placed in a new secondary containment berm lined with HDPE geomembrane for environmental compliance.

The system will be set up so the fuel in each tank can be individually treated using the portable fuel conditioning trailer. This will be accomplished using isolation valves at each tank, and connections on the supply and return lines at each fuel tank so they can be hooked up and circulated through the fuel conditioning trailer.

6.2 Electrical

The Electrical Basis of Design considers two primary systems:

- Power Delivery System: This system comprises the electrical equipment required to connect the combustion turbine (CT) generators to the existing substations at both sites.
- Power Distribution System: This system distributes power to all plant loads necessary to operate the generating units and support overall site requirements.

6.2.1 Power Delivery

The power delivery system is illustrated in the single-line diagrams for both sites.

At Greenhill, the system includes new 15 kV switchgear and associated cabling to connect:

- The existing unit transformer into the new CT for Unit 1; and
- The new unit transformer (by others, under Newfoundland Power switchyard scope and not included in this estimate) to the new CT for Unit 2.

Each generating unit at Greenhill is connected to its respective unit transformer through the 15 kV switchgear and associated cabling.

At Wesleyville, one generating unit is connected to the existing unit transformer through new 15 kV switchgear and associated cabling. The 15 kV switchgear provides the interface between the CT generator and the existing station infrastructure, enabling integration with the current substation while supporting safe operation, protection, and isolation of the generating unit.

6.2.2 Power Distribution

At Greenhill, the power distribution system is supplied from a feeder originating at the new 15 kV switchgear. This feeder energizes a new station service transformer sized to supply all site services and auxiliary systems, including CT starting motors.

Station services are supported by a standby diesel generator sized to provide black-start capability for one generating unit at a time but interconnected to provide operator selectability for both units.

Power transfer and distribution are managed through a 600 V switchgear lineup, which supplies:

- Motor control centers (MCCs)
- Building services
- General site loads

At Wesleyville, the existing low-voltage (LV) electrical infrastructure will be reused to the greatest extent practical.

Similar to Greenhill, a new main station service transformer will be installed and supplied from the new 15 kV switchgear. The system will also include:

- A standby generator
- An automatic transfer switch

These components will support both the existing LV distribution system and new MCCs associated with the CT installation.

6.2.3 Common Design Considerations (Both Sites)

The following elements are included in the design for both sites:

- Cable Management
- Cable tray systems within the new building
- Buried conduit for power distribution between buildings
- Precast trenching between the control building and switchyard
- Grounding
- Grounding systems designed for all electrical equipment
- Building Services
- Interior lighting, heating, and power
- Fire alarm and access control systems
- Exterior site lighting
- DC Systems
- DC battery banks and distribution systems
- Uninterruptible Power Supply (UPS)
- UPS systems to provide reliable AC power to control room and telecommunications equipment
- AC Services
- Panelboards and associated step-down transformers
- Provision of welding receptacles for construction and maintenance activities
- Heat Tracing
- Heat tracing systems for exterior fuel piping

6.3 Instrumentation and Control

The Instrumentation & Control design basis and cost estimate for both the Greenhill and Wesleyville sites is based on an on-skid turbine control system for each combustion turbine (vendor supplied; quantity 2 for Greenhill and quantity 1 for Wesleyville), a remote manual synchronization and HMI panel for each combustion turbine (vendor supplied; quantity 2 for Greenhill and quantity 1 for Wesleyville) a Balance of Plant (BOP) control system, associated interfaces between these components and interface between the BOP control system and Energy Control Center SCADA. See control system network architecture drawings for further details regarding the equipment, instrumentation and functionality that comprise the combustion turbine and BOP control systems.

6.4 Protection and Control

The Protection & Control design basis and cost estimate for both the Greenhill and Wesleyville sites is based on an on-skid generator protection system for each combustion turbine (vendor supplied; quantity 2 for Greenhill and quantity 1 for Wesleyville), a Neutral/Ground Resistor (NGR) system for each combustion turbine (quantity 2 for Greenhill and quantity 1 for Wesleyville), a bus differential protection system for each 15 kV switchgear bus (quantity 2 for Greenhill and quantity 1 for Wesleyville), interfaces between all of these systems, interfaces between all of these systems and the 15 kV switchgear, interfaces between the 15 kV switchgear bus protection systems/the NGR systems and the Balance of Plant Control system (for alarming) and interfaces between each Generator Step-Up (GSU) Transformer protection system (by others; quantity 2 for Greenhill and quantity 1 for Wesleyville) and both the associated 15 kV switchgear and 15 kV switchgear bus differential protection system. See control system network architecture drawings and cable block diagrams for further details.

6.5 Civil/Structural

Preliminary estimates have been completed for new foundations including combustion turbines and associated stack foundations, transformer, black start diesel generator and a new fuel building for both sites. For the Greenhill site, a new control building and for the Wesleyville site a partial replacement of the existing control building (to be repurposed) has been included.

Environmental loading for the Greenhill site was based on Grand Bank climatic data and for the Wesleyville site, environmental loading was based on Bonavista climatic data. All structures located on both sites were considered post disaster importance category.

6.5.1 Foundations

All foundations were assumed reinforced cast-in-place concrete, with a minimum 28-day compressive strength of 35 MPa, reinforcing in accordance with G30.18:21, Carbon Steel Bars for Concrete Reinforcement.

Limited geotechnical investigation information was available for the study and would be required for project design. Assumptions made in the study were based on information available.

Foundations for combustion turbines and exhaust stacks at both sites have been assumed to be supported on bedrock, based on the foundations for the existing turbines which indicates bedrock approximately 1500-1800 mm below surface. Based on this, it has also been assumed that the new building foundations will extend to bedrock.

The estimate includes a slab on grade for the Greenhill Control Building, Greenhill Fuel Building and Wesleyville Fuel Building.

No slab or foundation modifications have been considered for the Wesleyville Control Building, though it should be investigated further during detailed design.

Shallow foundations have been considered for the transformer and black start diesel generator units.

6.5.2 Structural Steel

The estimate includes a new steel framed structure for the Greenhill Control Building, Greenhill Fuel Building and Wesleyville Fuel Building.

For the Wesleyville Control Building, partial replacement of the building has been considered. The estimate for the repurposed portion is a steel frame structure, assuming no reuse of existing steel components. This evaluation did not consider the current capacity of the existing building, which should be investigated during detailed design.

Structural steel utilised for the buildings includes:

- Structural W shape, S shape and WT shape sections, in accordance with CSA G40.20/G40.21 Grade 350W, ASTM A572 Grade 50 or ASTM A992.
- Channels and angles structural steel members, in accordance with CSA G40.21/G40.20 Grade 300W,
- Steel plates, in accordance with CSA G40.20/G40.21 Grade 300W minimum.

6.5.3 Earthworks

A geotechnical report from 2001 is available for the Wesleyville site. It includes five test pits, which yielded the following depths:

- Average depth of unsuitable material (organics/topsoil): 0.74 m
- Average depth to bedrock: 1.82 m
- Average depth to groundwater: 0.78 m

The underlying soil is primarily glacial till with high fines content. The native till is frost susceptible and at risk of instability if saturated. When excavating till from the site, only material excavated from above the water table is suitable for reuse in other areas. All other material excavated from the site should be removed and disposed.

The existing Wesleyville site is a relatively flat, rectangular area. Within the existing fenced area, ground surface levels vary from 16.5 m in the southwest corner to 15.5 m in the northeast corner. The proposed site includes an extension to the east to accommodate the new turbine and fuel tanks. As such, it is recommended that a geotechnical investigation is completed in the extension area prior to detailed design. Site survey information indicates a localized low point in the vicinity of the proposed extension. The site drops down to a level of approximately 14.5 m and will require infill to build up to the same level as the existing yard.

No geotechnical information is available for the Greenhill site. It is recommended that a geotechnical investigation is completed prior to detailed design. Unforeseen soil conditions create a risk of increased construction complexity and costs. For estimating purposes, it has been assumed that there is 1.0 m of unsuitable material to be stripped from the ground surface in areas of work, and that none of the excavated material onsite is suitable for reuse.

The existing Greenhill site consists of two distinct levels. The existing building and turbine are in a relatively flat area at an elevation of approximately 18.0 m. To the east of the building, there is an undeveloped gravel area at an elevation of 20.5 m. There is a hill with a crest of 22.0 m separating the two areas. The proposed control building and turbines will be constructed at the upper level of the site. This will involve excavating material to level the existing hill crest to increase the size of the 20.5 m elevation area.

Proposed gravel areas at both sites will consist of a cross section with 300 mm granular Class B below 150 mm granular Class A. The final design of this structure is recommended to be included in the subsequent geotechnical investigation mentioned above.

The fuel containment system at both sites will consist of an earthen berm approximately 900 mm high. The core of the berm will be 100 mm minus rock fill, capped with an impermeable liner system. The liner system consists of the following layers (listed top to bottom):

- 150 mm granular Class B
- Geotextile
- 150 mm sand
- Geotextile
- Impervious HDPE liner
- Geotextile
- 100 mm sand
- Geotextile
- 100 mm minus rockfill

6.5.4 Drainage

Both existing sites do not have any underground stormwater infrastructure. The sites are graded to provide positive drainage away from all buildings and equipment. Proposed development areas will similarly be graded away from buildings and equipment without any underground piping. Proposed access roads will be crowned in the centre to direct runoff to the shoulders and into roadside ditches. It is assumed that no stormwater detention is required.

Within the tank containment berms, there will be a sump pit at a low point to collect surface runoff. A pump will be required to drain the sump and discharge water away from the site.

6.5.5 Water and Sewer

At Greenhill, domestic water is provided from the Town of Grand Bank. It assumed that this water supply is adequate and the new building will be serviced from the same line.

Domestic water at Wesleyville is provided by an artesian well, but flow rates and water quality are both insufficient. Due to known groundwater issues in the area, the artesian well will be abandoned, and the Wesleyville site will include a potable water holding tank instead. The recommended solution is two stacked

1,000 L tanks (2,000 L total). 2,000 L is enough for approximately two months of water usage. Estimated water usage was based on two staff working one 8-hour shift onsite per week, and a water demand of 115 L/person/day. The tanks should be refilled when they reach one third of its capacity, which corresponds to a filling frequency of approximately once every five weeks.

Both sites have existing septic systems for wastewater treatment. According to 2002 design drawings, Wesleyville has a septic holding tank but no absorption field. It is possible that there is no absorption field and this tank is periodically emptied by pumper truck. 1975 design drawings for Greenhill indicate an absorption field with four 16.8 m long trenches. The condition of these septic systems is unknown, and it is assumed that they are the same age as the existing buildings. The typical lifespan for a septic system is Newfoundland is approximately 30-40 years (with regular maintenance). It is expected that the Greenhill septic system has exceeded its effective lifespan and the Wesleyville septic system is nearing the end of its operational lifespan (if an absorption field exists).

Although there have been no performance concerns noted for the existing systems, it is recommended that new septic systems are added for both sites due to the age of existing infrastructure. New systems can also be constructed near the proposed buildings rather than trying to run sanitary sewer pipes across the sites. The proposed septic systems will consist of septic tanks, distribution boxes, and absorption fields, and will be designed in accordance with the Newfoundland and Labrador Private Sewage Disposal and Water Supply Guidelines. Due to the small rate of wastewater generation at each site, the absorption fields will be designed for the minimum allowable field length of 60 m. The recommended layout is four 15 m trenches for a total footprint area of 16.0 m x 7.5 m.

6.5.6 Fencing and Gates

Both sites require new fencing and gates to enclose the proposed developments.

The existing fence at Wesleyville is a 2.4 m high chain link fence with 300 mm barbed wire. For Greenhill, fence details were not provided. However, from scaled site photos, it appears the existing fence is 2.1 m tall with 300 mm barbed wire. Exact height is to be confirmed in the field, and new fences should be designed to match existing.

Wesleyville requires new fencing around the site expansion to the east. In Greenhill, new fencing is required around the proposed fuel tank area and the proposed building and turbine area. Both sites require a new 6.0 m wide swing gate for vehicles and a standard man gate for personnel entry.

6.5.7 Vehicle Access

The design vehicle is a fuel truck with a 16.2 m (53') trailer. For modelling purposes, a WB-20 tractor-semitrailer (22.7 m total length) was used. This design vehicle was analyzed using AutoTurn software, so that trucks can access the site and efficiently reach refueling areas.

The Wesleyville site is located adjacent to a gravel area (outside the site fence) which is large enough for trucks to turn around. This existing gravel area will be extended along the proposed eastern expansion of the site. Fuel trucks can drive past the site entrance, then reverse through the double gates to enter and refuel. When exiting, they can drive straight out the gates and turn right to exit the site.

At Greenhill, the tank/refuelling station and control building/turbines are in different areas. For refuelling and tank access, trucks will follow the existing access road and enter through the existing gates. They can then make a three-point turn inside the site fence or reverse through the gates to exit. A new access road is required to reach the proposed control building and turbines. Due to the grade differential between the new building area and the existing site, it is not practical to connect the two with a new access road. Large trucks accessing the building/turbine area will be required to reverse out the length of the access road to exit the site. Smaller vehicles will be able to turn around inside the new fence.

Also at Greenhill, there is an existing access track used by the community running through the proposed turbine area. Although this track is on the Newfoundland Power property, it is regularly used by members of the public and should be realigned to run outside the proposed fence so that it can still be used.

7 Construction Schedule

Preliminary construction execution schedules were developed to support project planning and estimate development. The schedules incorporate engineering, procurement, environmental approval, construction, commissioning, and startup activities.

The schedules indicate overall project durations of approximately five (5) years. Major equipment procurement, particularly combustion turbine delivery, is the principal schedule driver. Recent vendor and client reviews indicate turbine delivery lead times approaching four (4) years and have been reflected within the schedule assumptions.

To mitigate schedule risk, it is recommended that environmental approvals, engineering development, and procurement planning commence as early as practical following project approval.

Refer to Appendix A for the project schedule.

8 References

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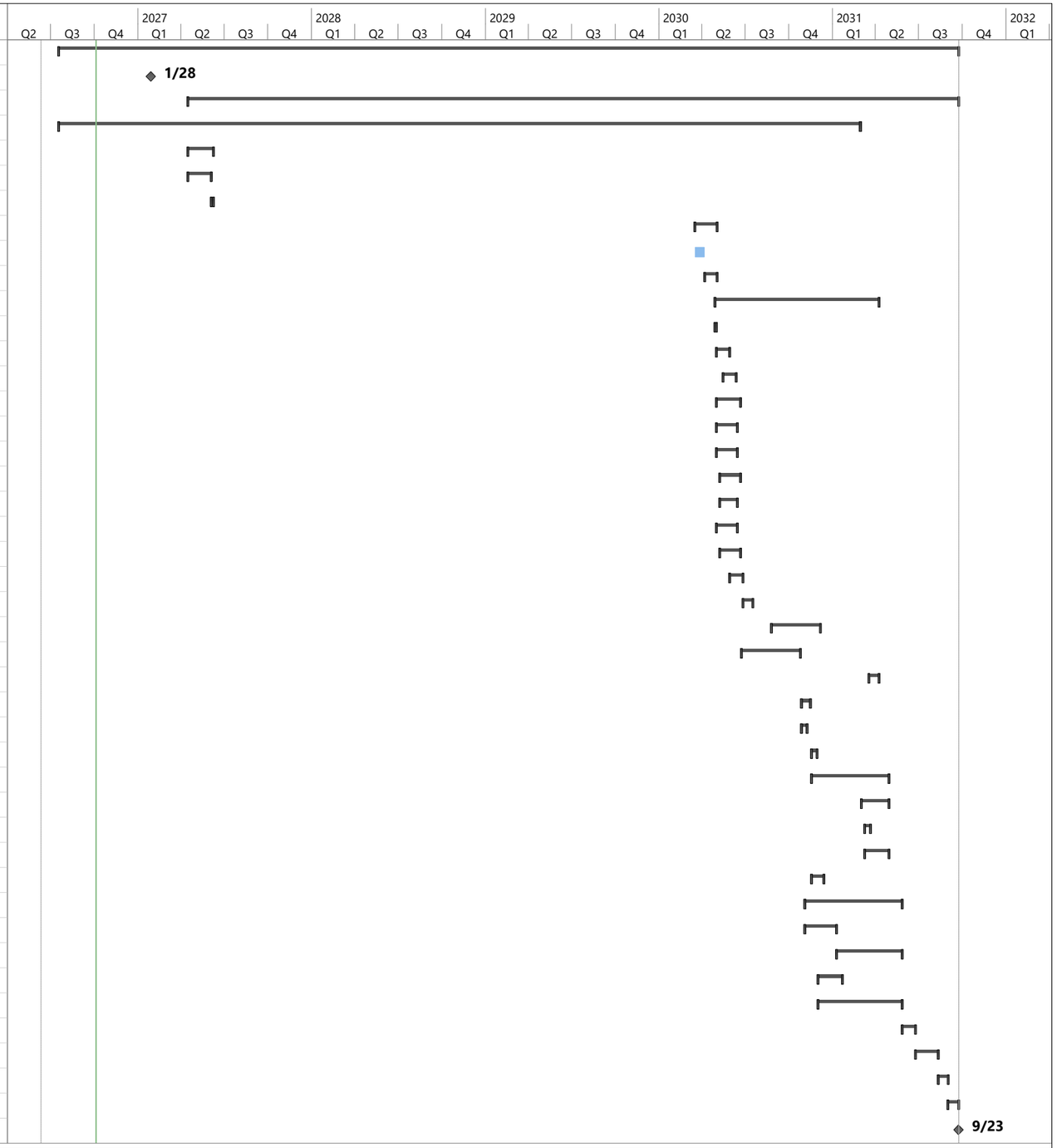
8.2 Personal Communications

Pers. Comm. NLDECCC, 2026. Email from Dexter Pittman, NLDECCC, June 17, 2026, to Victoria Corning at Stantec regarding anticipated industrial approval and air quality monitoring requirements

APPENDICES

Appendix A Project Schedule

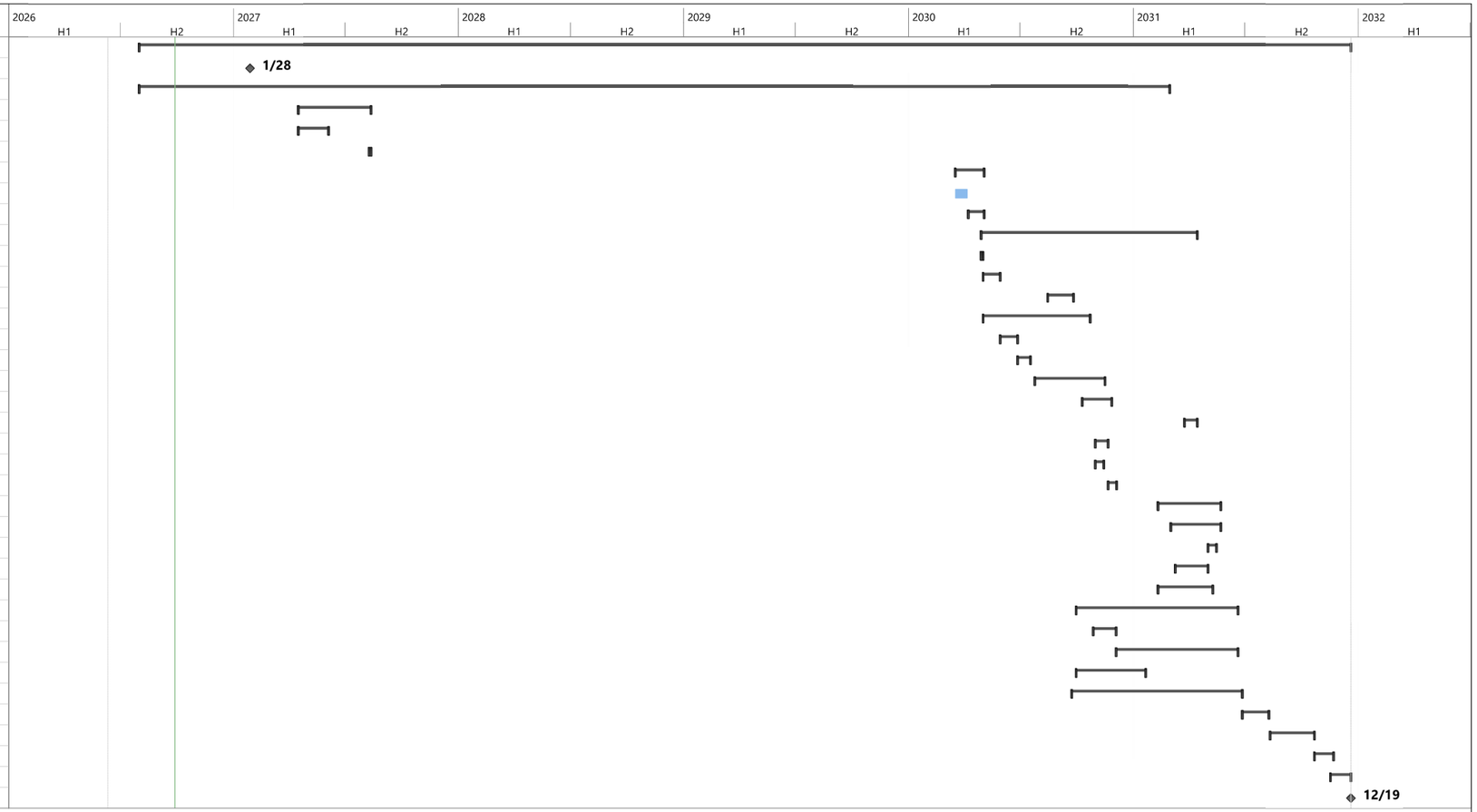
ID	Task Name	Duration	Start	Finish
1	**Wesleyville Combustion Turbine - PRELIMINARY**	**1343 days**	**Fri 7/17/26**	**Tue 9/23/31**
2	**PUB Approval**	**0 days**	**Thu 1/28/27**	**Thu 1/28/27**
3	**Milestones/Summary**	**1151.75 days**	**Fri 4/16/27**	**Tue 9/23/31**
15	**Engineering & Procurement**	**1196 days**	**Fri 7/17/26**	**Fri 2/28/31**
20	**Site Preparation**	**38 days**	**Fri 4/16/27**	**Wed 6/9/27**
21	**Clearing, Grubbing, Fill & Grading**	**35 days**	**Fri 4/16/27**	**Fri 6/4/27**
25	**Survey & Geotechnical**	**3 days**	**Fri 6/4/27**	**Wed 6/9/27**
27	**Mobilization**	**35 days**	**Mon 3/18/30**	**Fri 5/3/30**
28	**Contractor Mobilization**	**15 days**	**Mon 3/18/30**	**Fri 4/5/30**
29	**Temporary Construction Facilities (Contractor Mobilization)**	**20 days**	**Mon 4/8/30**	**Fri 5/3/30**
39	**Civil Works**	**245 days**	**Mon 4/29/30**	**Tue 4/8/31**
40	**Excavation & Earthworks**	**3 days**	**Mon 4/29/30**	**Wed 5/1/30**
43	**Site Drainage Improvements & UG Utilities**	**20 days**	**Thu 5/2/30**	**Wed 5/29/30**
48	**Ground Grid System Expansion to New Area and Upgrade of Existing area**	**20 days**	**Thu 5/16/30**	**Wed 6/12/30**
50	**Foundations**	**37 days**	**Thu 5/2/30**	**Fri 6/21/30**
51	**Combustion Turbine(s) Foundation**	**32 days**	**Thu 5/2/30**	**Fri 6/14/30**
55	**Exhaust Stack(s) Foundation**	**32 days**	**Thu 5/2/30**	**Fri 6/14/30**
59	**Black Start Diesel Foundation**	**32 days**	**Thu 5/9/30**	**Fri 6/21/30**
63	**Station Service Transformer Foundations**	**27 days**	**Thu 5/9/30**	**Fri 6/14/30**
67	**Fuel Tanks Foundations**	**32 days**	**Thu 5/2/30**	**Fri 6/14/30**
71	**Fuel Forwarding Building Foundations**	**32 days**	**Thu 5/9/30**	**Fri 6/21/30**
75	**Waste Oil Containment**	**20 days**	**Thu 5/30/30**	**Wed 6/26/30**
77	**Water & Sewer**	**15 days**	**Thu 6/27/30**	**Wed 7/17/30**
79	**Building Modifications/ Switchgear Room**	**75 days**	**Mon 8/26/30**	**Fri 12/6/30**
88	**Fuel Forwarding Building**	**90 days**	**Mon 6/24/30**	**Fri 10/25/30**
96	**Access platforms, stairways, ladders, handrails for fuel tanks**	**15 days**	**Wed 3/19/31**	**Tue 4/8/31**
98	**Permanent Roads, Parking & Acess Areas**	**15 days**	**Mon 10/28/30**	**Fri 11/15/30**
100	**Permanent Fencing**	**10 days**	**Mon 10/28/30**	**Fri 11/8/30**
102	**Final Grading, Dranage & site Restoration**	**10 days**	**Mon 11/18/30**	**Fri 11/29/30**
104	**Mechanical**	**115 days**	**Mon 11/18/30**	**Tue 4/29/31**
105	**Combustion Turbine**	**42 days**	**Mon 3/3/31**	**Tue 4/29/31**
112	**Black Start Diesel**	**10 days**	**Mon 3/10/31**	**Fri 3/21/31**
114	**Fuel Systems**	**37 days**	**Mon 3/10/31**	**Tue 4/29/31**
119	**Building Systems**	**20 days**	**Mon 11/18/30**	**Fri 12/13/30**
121	**Electrical**	**145 days**	**Mon 11/4/30**	**Tue 5/27/31**
122	**Switchgear, MCC & Station Service**	**47 days**	**Mon 11/4/30**	**Thu 1/9/31**
127	**Combustion Turbine Systems**	**98 days**	**Fri 1/10/31**	**Tue 5/27/31**
131	**Building & Site Systems**	**35 days**	**Mon 12/2/30**	**Tue 1/21/31**
138	**Instrumentation & Controls**	**125 days**	**Mon 12/2/30**	**Tue 5/27/31**
147	**Pre Commissioning**	**20 days**	**Wed 5/28/31**	**Tue 6/24/31**
152	**Commissioning & Testing**	**34 days**	**Wed 6/25/31**	**Mon 8/11/31**
166	**Start up**	**15 days**	**Tue 8/12/31**	**Mon 9/1/31**
174	**Close Out**	**17 days**	**Mon 9/1/31**	**Tue 9/23/31**
180	**Final Acceptance**	0 days	Tue 9/23/31	Tue 9/23/31



Project: NLP_CT_Wesleyville_Pre
Date: Mon 10/5/26

Task
Split
Milestone
Summary
Project Summary
Inactive Task
Inactive Milestone
Inactive Summary
Manual Task
Duration-only
Manual Summary Rollup
Manual Summary
Start-only
Finish-only
External Tasks
External Milestone
Deadline
Progress
Manual Progress

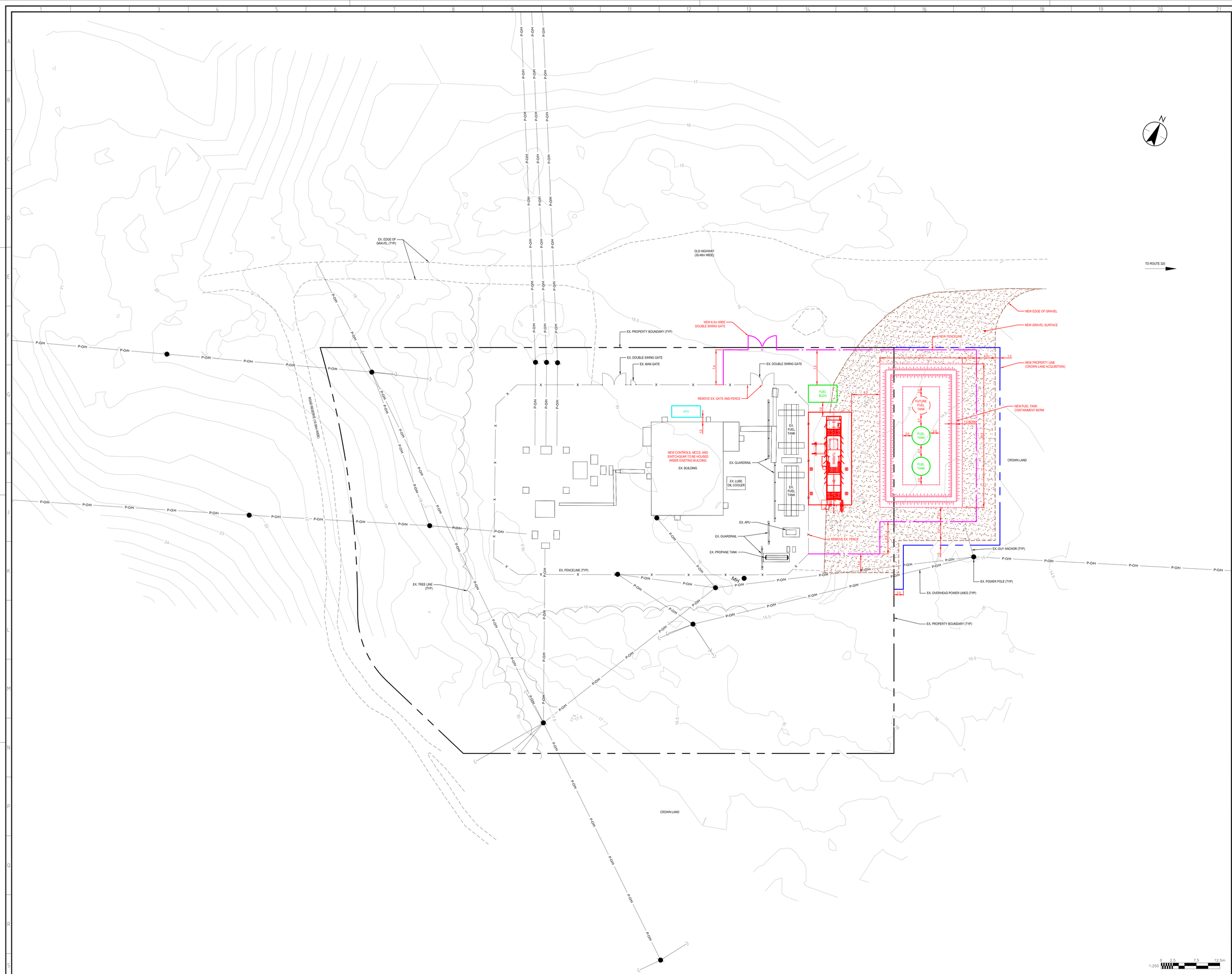
ID	Task Name	Duration	Start	Finish
1	**Greenhill Combustion Turbine - PRELIMINARY**	**1396 days**	**7/31/2026**	**12/19/2031**
2	**PUB Approval**	0 days	1/28/2027	1/28/2027
3	**Engineering & Procurement**	**1186 days**	**7/31/2026**	**2/28/2031**
8	**Site Preparation**	**84 days**	**4/16/2027**	**8/12/2027**
9	**Clearing, Grubbing, Fill & Grading**	**35 days**	**4/16/2027**	**6/4/2027**
13	**Survey & Geotechnical**	**3 days**	**8/9/2027**	**8/12/2027**
15	**Mobilization**	**35 days**	**3/18/2030**	**5/3/2030**
16	**Contractor Mobilization**	15 days	3/18/2030	4/5/2030
17	**Temporary Construction Facilities (Contractor Mobiliza**	**20 days**	**4/8/2030**	**5/3/2030**
27	**Civil Works**	**249 days**	**4/29/2030**	**4/14/2031**
28	**Excavation & Earthworks**	**3 days**	**4/29/2030**	**5/1/2030**
31	**Site Drainage Improvements & UG Utilities**	**20 days**	**5/2/2030**	**5/29/2030**
36	**Ground Grid System Expansion to New Area and Upgra**	**30 days**	**8/15/2030**	**9/25/2030**
38	**Foundations**	**124 days**	**5/2/2030**	**10/22/2030**
67	**Waste Oil Containment**	**20 days**	**5/30/2030**	**6/26/2030**
69	**Water & Sewer**	**15 days**	**6/27/2030**	**7/17/2030**
71	**Control Building**	**82 days**	**7/25/2030**	**11/15/2030**
79	**Fuel Forwarding Building**	**34 days**	**10/10/2030**	**11/26/2030**
86	**Access Platforms, Stairways, Ladders, Handrails for Fue**	**15 days**	**3/25/2031**	**4/14/2031**
88	**Permanent Roads, Parking & Access Areas**	**15 days**	**10/31/2030**	**11/20/2030**
90	**Permanent Fencing**	**10 days**	**10/31/2030**	**11/13/2030**
92	**Final Grading, Drainage & Site Restoration**	**10 days**	**11/21/2030**	**12/4/2030**
94	**Mechanical**	**74 days**	**2/10/2031**	**5/22/2031**
95	**Combustion Turbine**	**59 days**	**3/3/2031**	**5/22/2031**
102	**Black Start Diesel**	**10 days**	**5/2/2031**	**5/15/2031**
104	**Fuel Systems**	**39 days**	**3/10/2031**	**5/1/2031**
109	**Building Systems**	**65 days**	**2/10/2031**	**5/9/2031**
112	**Electrical**	**187 days**	**9/30/2030**	**6/19/2031**
113	**Switchgear, MCC & Station Service**	**27 days**	**10/28/2030**	**12/3/2030**
117	**Combustion Turbine Systems**	**140 days**	**12/4/2030**	**6/19/2031**
121	**Building & Site Systems**	**79 days**	**9/30/2030**	**1/20/2031**
129	**Instrumentation & Controls**	**197 days**	**9/23/2030**	**6/26/2031**
138	**Pre Commissioning**	**31 days**	**6/27/2031**	**8/8/2031**
143	**Commissioning & Testing**	**52 days**	**8/11/2031**	**10/21/2031**
157	**Start up**	**23 days**	**10/22/2031**	**11/21/2031**
165	**Close Out**	**25 days**	**11/17/2031**	**12/19/2031**
170	**Final Acceptance**	0 days	12/19/2031	12/19/2031



Project: NLP_CT_Greenhill_Prelim
Date: 9/28/2026

Task | Split | Milestone | Summary | Project Summary | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary | Start-only | Finish-only | External Tasks | External Milestone | Deadline | Progress | Manual Progress

Appendix B Site Plan



NOTES:

REV	DATE	DESCRIPTION	APPROVED
B	26-07-10	ISSSUED FOR CLASS 3 STUDY	C.F.
A	26-06-19	ISSSUED FOR CLASS 3 STUDY	C.F.

REVISION HISTORY

DWG # | TITLE

REFERENCE DRAWINGS

NEWFOUNDLAND POWER
A FORTIS COMPANY

SITE: WESLEYVILLE (WES)

PROJECT: GAS TURBINE REPLACMENT | PROJECT #

TITLE: PROPOSED SITE PLAN

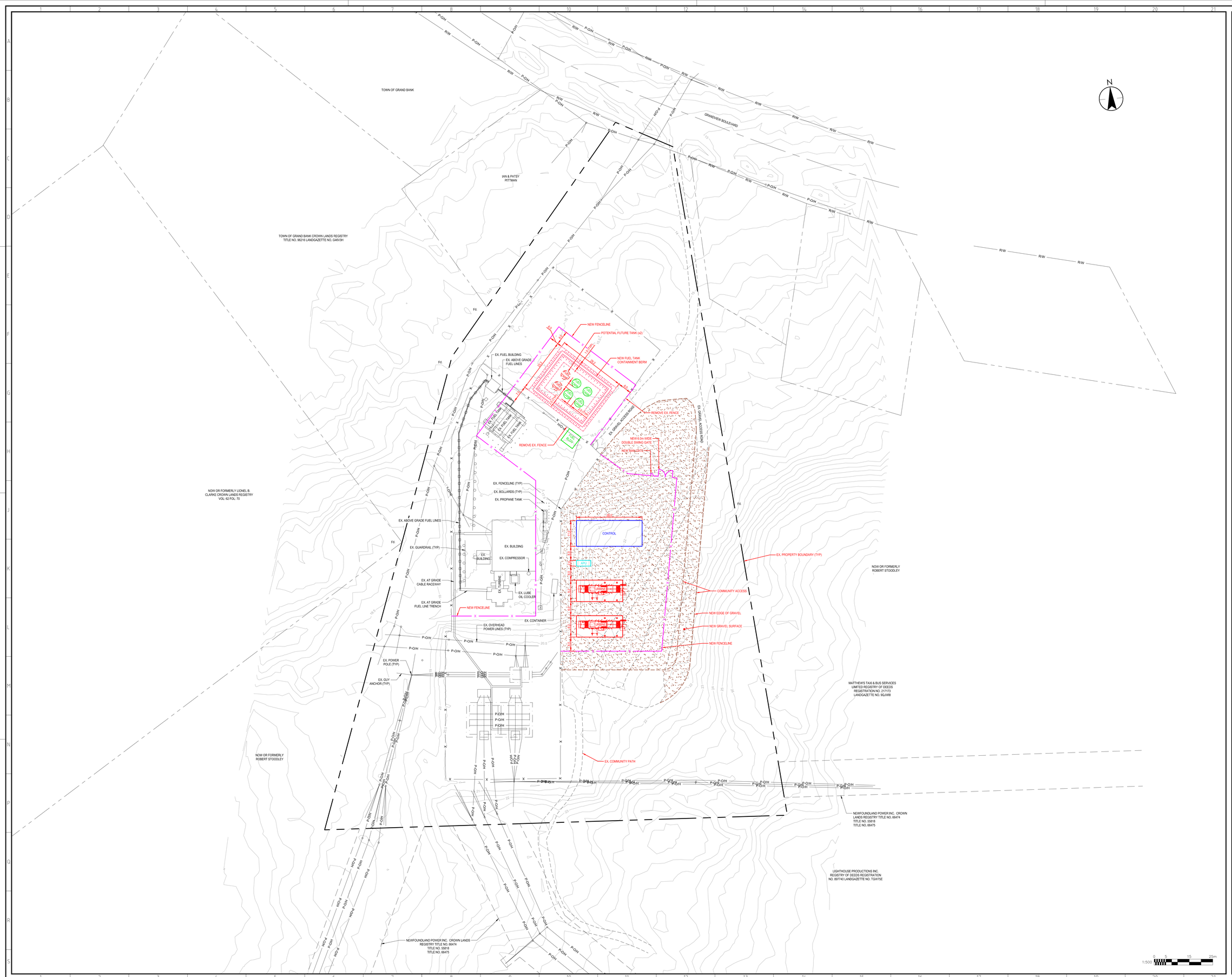
REV DESCRIPTION:

DESIGNED: C. FLANAGAN | CHECKED: N/A

DRAWN: R. CORNISH | APPROVED:

SCALE: 1:250 | DRAWING NUMBER: C-1002 1 OF 1 | REVISION: B

DATE: 2026/07/02



NOTES:

REV	DATE	DESCRIPTION	APPROVED
DWG #		TITLE	
REFERENCE DRAWINGS			
B	26-07-10	ISSSUED FOR CLASS 3 STUDY	C.F.
A	26-06-19	ISSSUED FOR CLASS 3 STUDY	C.F.

REVISION HISTORY

NEWFOUNDLAND POWER
A FORTIS COMPANY

SITE: GREENHILL (GRH)

PROJECT: GAS TURBINE REPLACEMENT

PROJECT #

TITLE: PROPOSED SITE PLAN

REV DESCRIPTION:

DESIGNED: C. FLANAGAN | CHECKED: N/A

DRAWN: R. CORNISH | APPROVED:

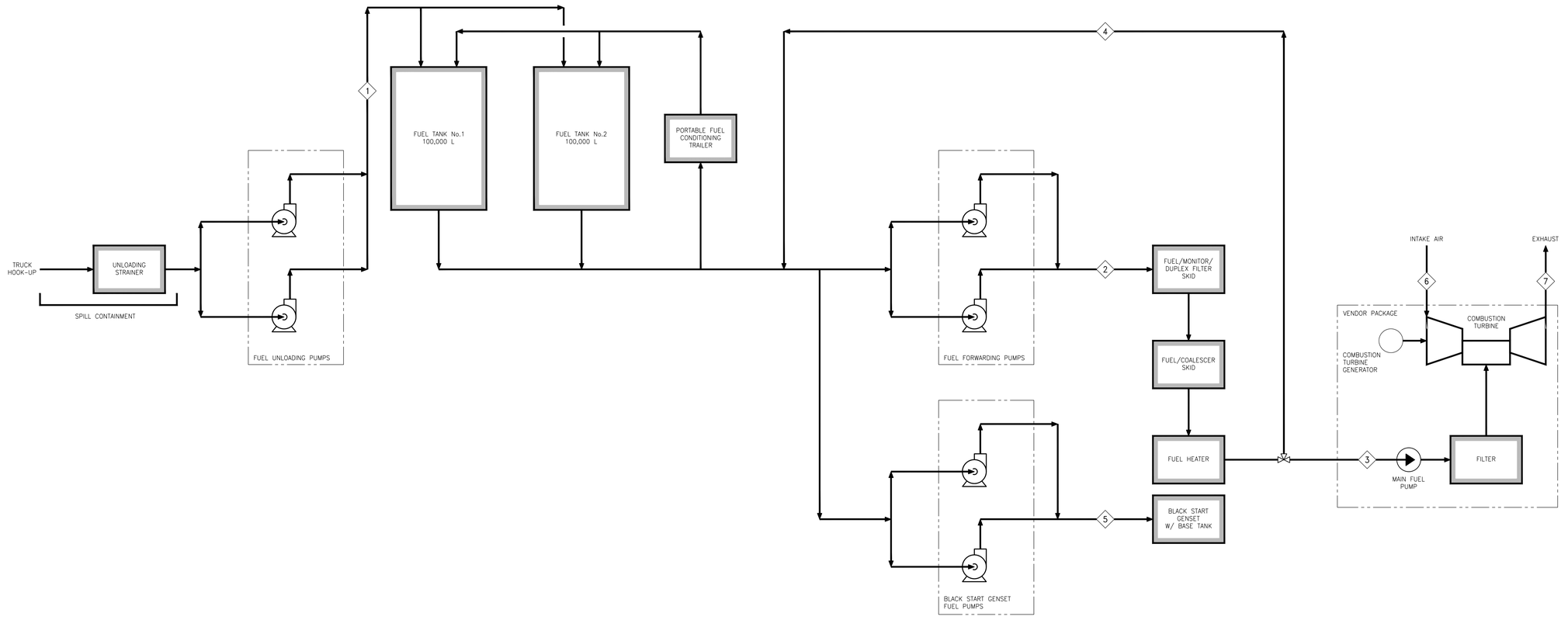
SCALE: 1:500 | DATE: 2026/07/02

DRAWING NUMBER: C-1002
1 OF 1

REVISION: B

Appendix C Process Flow Diagrams (PFD)

STREAM NO.	◇1			◇2			◇3			◇4			◇5			◇6			◇7		
DESCRIPTION																					
FLOW CONDITIONS	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX
FLOW (USGPM)	0	0	250	–	–	–	–	19.2	–	–	–	–	–	–	–	–	–	–	–	–	–
PRESSURE (PSIG)	–	–	–	–	–	–	10	–	100	–	–	–	–	–	–	–	–	–	–	–	–
TEMPERATURE (°F)	–	–	–	–	–	–	–	–	140	–	–	–	–	–	–	–	–	–	–	–	–



REFERENCE DRAWINGS

DWG. No.	TITLE	BY

PRELIMINARY
FOR INFORMATION ONLY

REV.	ISSUED TO	ISSUED FOR
B	AUG. 07, 2026 CLIENT	INFORMATION
A	JUN. 12, 2026 CLIENT	INFORMATION

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No.	DATE	BY	REVISIONS	DES.	DRG.	CHK.

DESIGNED TB	DRAWN CDO
CHECKED DESIGN / DFTG.	DATE MAY 19, 2026
	SCALE NTS
P.M. NH	SPEC.
P.T. CDO	

Stantec

GAS TURBINE REPLACEMENT

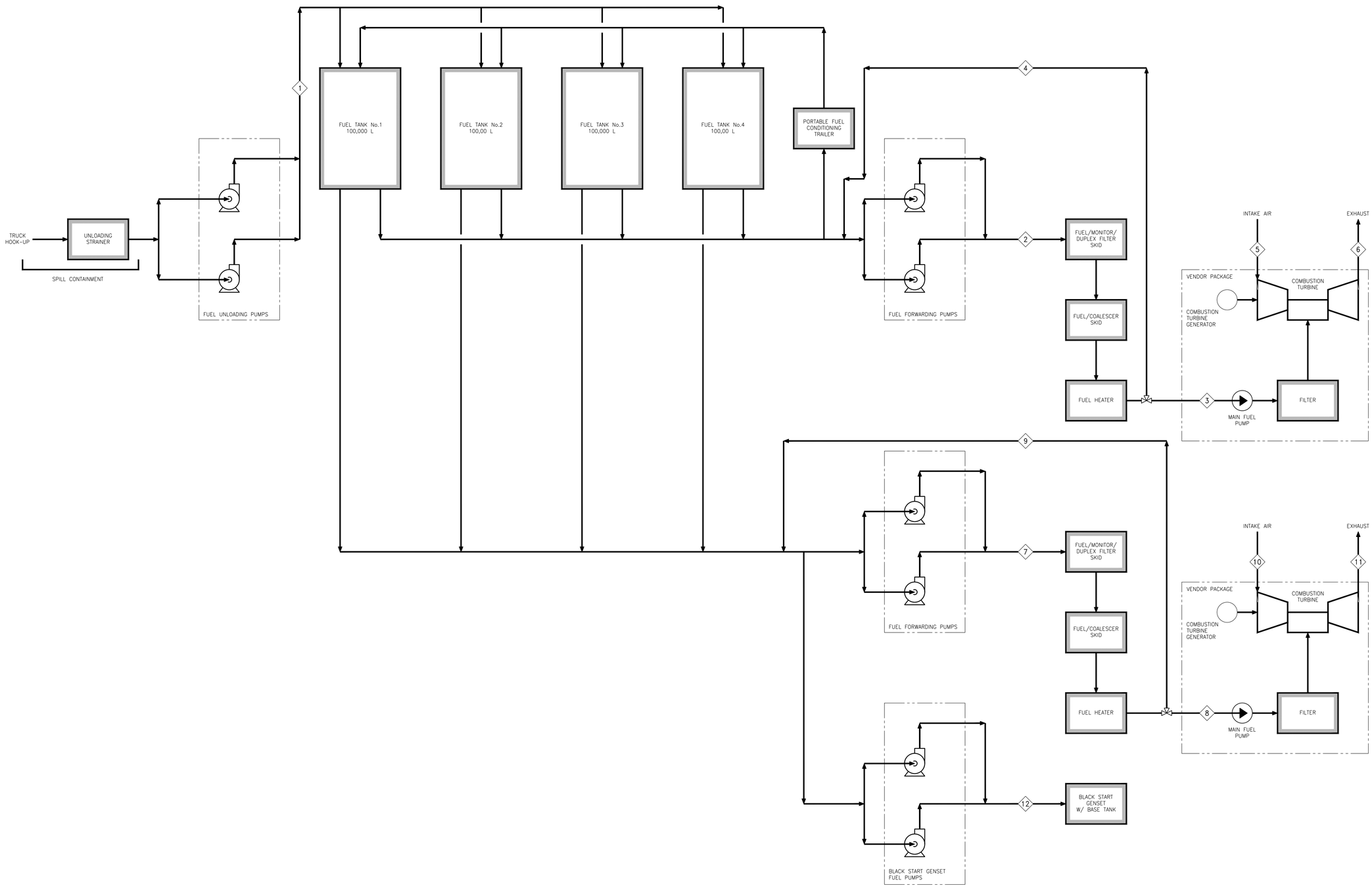
PROCESS FLOW DIAGRAM
FUEL SYSTEM
WESLEYVILLE

JOB No.	DWG. No.	REV
137026073	G-4021	B

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Aug 06, 2026 3:00pm cdunnett

STREAM NO.	1			2			3			4			5			6		
DESCRIPTION																		
FLOW CONDITIONS	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX
FLOW (USGPM)	0	0	250	–	–	–	–	19.2	–	–	–	–	–	–	–	–	–	–
PRESSURE (PSIG)	–	–	–	–	–	–	10	–	100	–	–	–	–	–	–	–	–	–
TEMPERATURE (°F)	–	–	–	–	–	–	–	–	140	–	–	–	–	–	–	–	–	–

STREAM NO.	7			8			9			10			11			12		
DESCRIPTION																		
FLOW CONDITIONS	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX	MIN	NORM	MAX
FLOW (USGPM)	–	–	–	–	19.2	–	–	–	–	–	–	–	–	–	–	–	–	–
PRESSURE (PSIG)	–	–	–	10	–	100	–	–	–	–	–	–	–	–	–	–	–	–
TEMPERATURE (°F)	–	–	–	–	–	140	–	–	–	–	–	–	–	–	–	–	–	–



REFERENCE DRAWINGS

DWG. No.	TITLE	BY

PRELIMINARY
FOR INFORMATION ONLY

REV.	ISSUED TO	ISSUED FOR
B	AUG. 07, 2026 CLIENT	INFORMATION
A	JUN. 12, 2026 CLIENT	INFORMATION

The Contractor shall verify and be responsible for all dimensions. DO NOT scale the drawing – any errors or omissions shall be reported to Stantec without delay. The Copyrights to all designs and drawings are the property of Stantec. Reproduction or use for any purpose other than that authorized by Stantec is forbidden.

No.	DATE	BY	REVISIONS	DES.	DRG.

DESIGNED TB	DRAWN CDO
CHECKED DESIGN / DFTG.	DATE MAY 19, 2026
	SCALE NTS
P.M. NH	SPEC.
P.T. CDO	

Stantec

GAS TURBINE REPLACEMENT

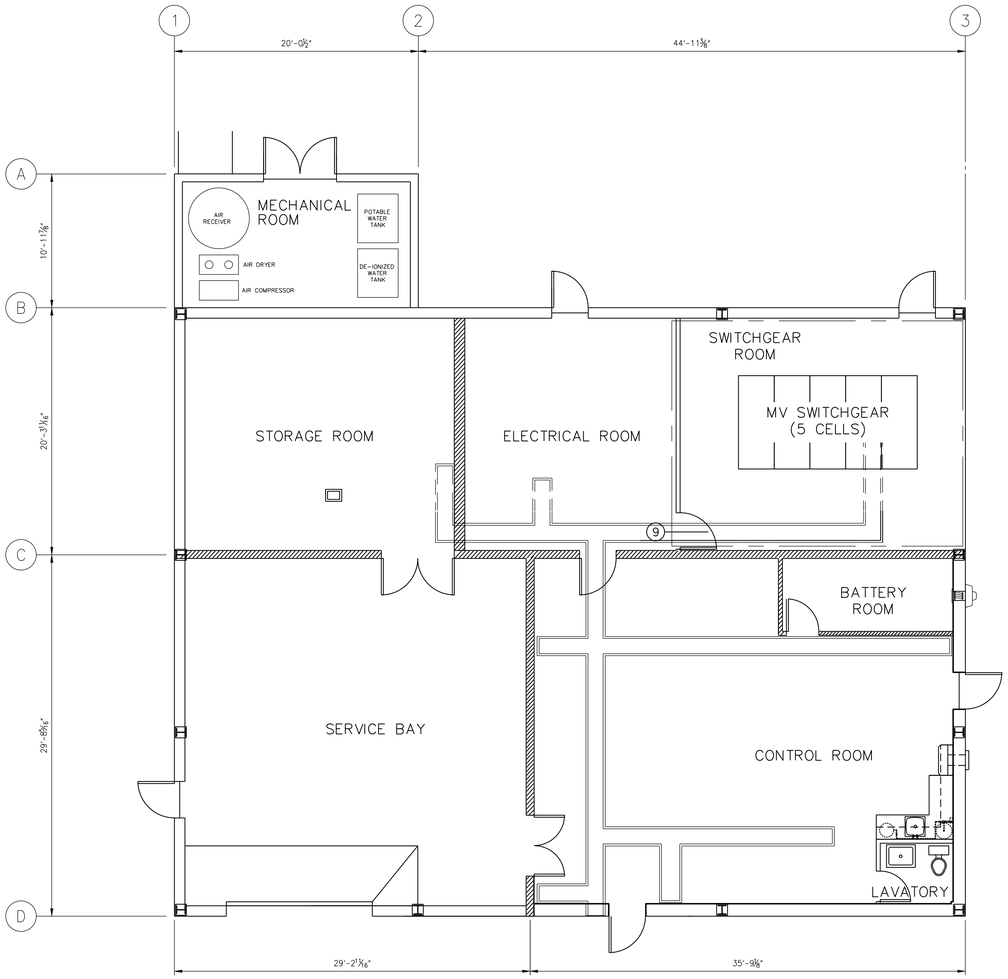
PROCESS FLOW DIAGRAM
FUEL SYSTEM
GREENHILL

JOB No.	DWG. No.	REV
137026073	G-4022	B

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Aug 06, 2026 3:01pm cdunnett

Appendix D General Arrangements (GA)



PLAN AT EL. XX'-XX" TOC (UNO)

SCALE: ¼"=1'-0"

REFERENCE DRAWINGS

DWG. No.	TITLE	BY

PRELIMINARY
FOR INFORMATION ONLY

REV.	ISSUED TO	ISSUED FOR
B	JUN. 19, 2026 CLIENT	INFORMATION
A	JUN. 12, 2026 CLIENT	INFORMATION

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No.	DATE	BY	REVISIONS	DES.

DESIGNED TB	DRAWN CDO
CHECKED DESIGN / DFTG.	DATE JUN. 10, 2026
	SCALE NTS
P.M. NH	SPEC.
P.T. CDO	

Stantec

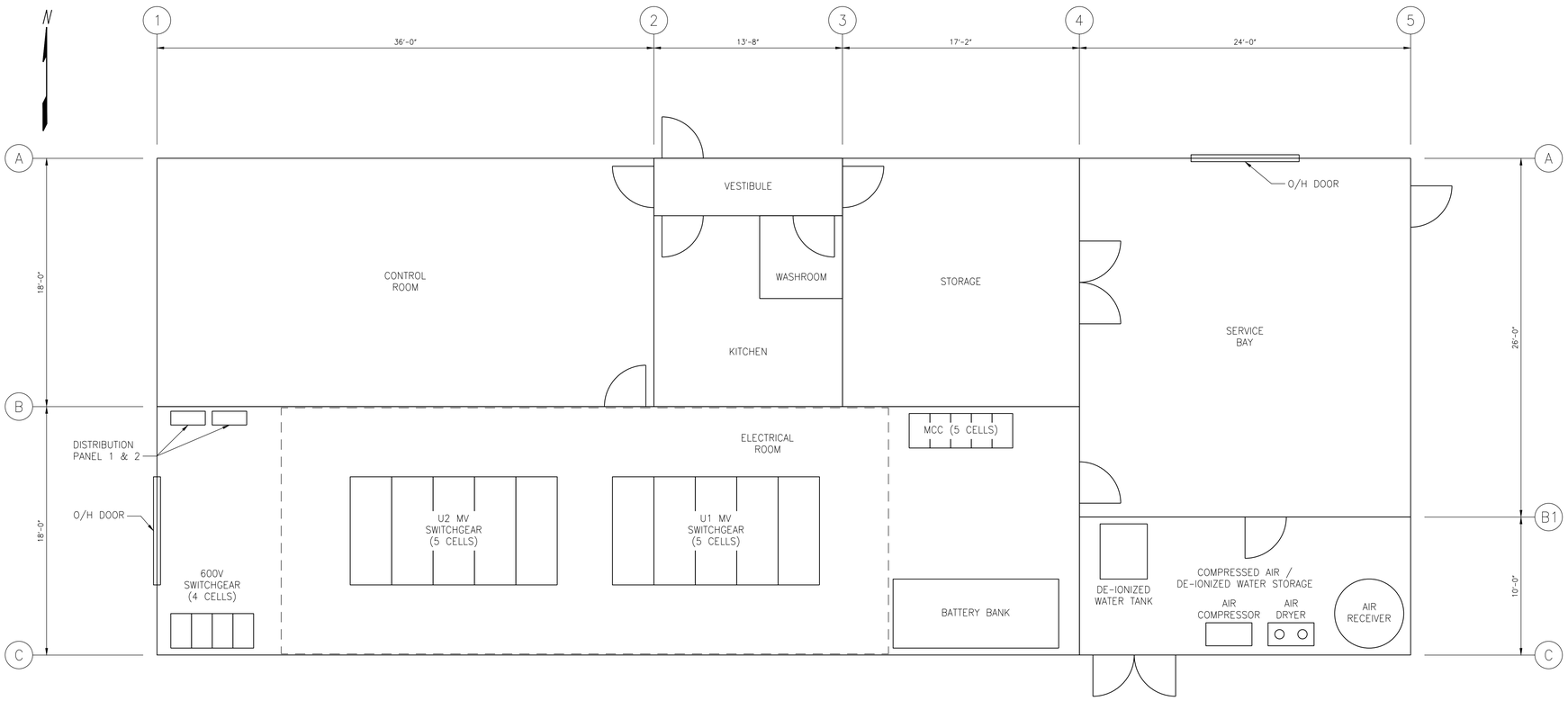
GAS TURBINE REPLACEMENT

GENERAL ARRANGEMENT
WESLEYVILLE BUILDING
PLAN AT EL. XX'-XX" TOC (UNO)
GRID 1-3 AND A-D

JOB No.	DWG. No.	REV
137026073	G-1002	B

Jul 10, 2026 3:07pm cdunnett

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PLAN AT EL. XX'-XX" TOC (UNO)

SCALE: ¼"=1'-0"

REFERENCE DRAWINGS

DWG. No.	TITLE	BY

PRELIMINARY
FOR INFORMATION ONLY

REV.	ISSUED TO	ISSUED FOR
C	JUL. 17, 2026 CLIENT	INFORMATION
B	JUN. 19, 2026 CLIENT	INFORMATION
A	JUN. 12, 2026 CLIENT	INFORMATION

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No.	DATE	BY	REVISIONS	DES.	DFTG.

DESIGNED TB		DRAWN CDO	
CHECKED		DATE JUN. 10, 2026	
DESIGN	DFTG.		
		SCALE NTS	
P.M. NH		SPEC.	
P.T. CDO			

Stantec

GAS TURBINE REPLACEMENT

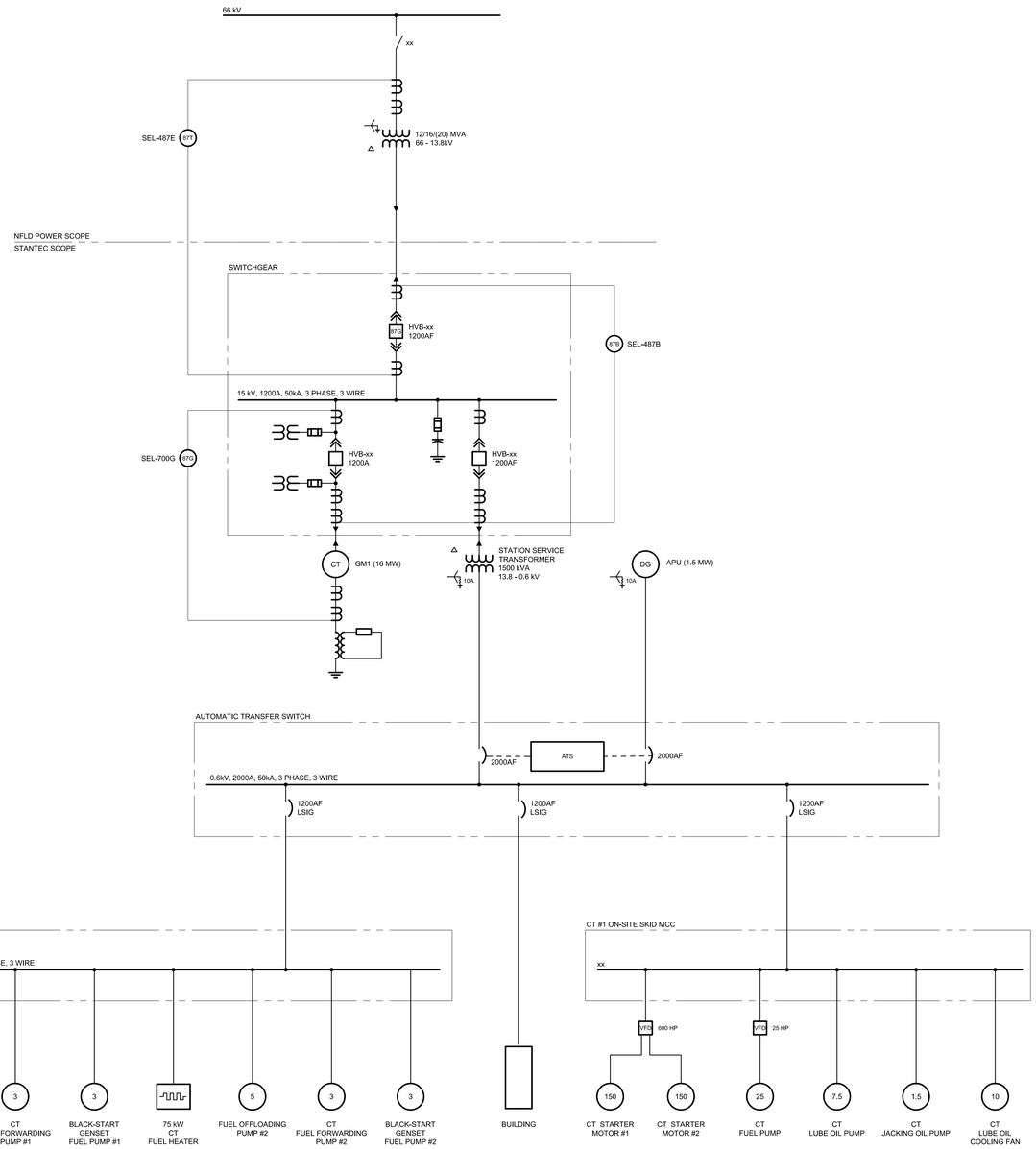
GENERAL ARRANGEMENT
GREENHILL BUILDING
PLAN AT EL. XX'-XX" TOC (UNO)
GRID 1-5 AND A-C

JOB No.	DWG. No.	REV
137026073	G-1001	C

Jul 10, 2026 2:54pm cdunnett

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Appendix E Single Line Diagrams (SLD)



NOTES:

Stantec

DWG #	TITLE
REFERENCE DRAWINGS	

REV	DATE	DESCRIPTION	APPROVED
A	JUL.03 2026	ISSUED FOR REVIEW	BDJ

REVISION HISTORY

NEWFOUNDLAND POWER
A FORTIS COMPANY

SITE: WESLEYVILLE (WES)

PROJECT: GAS TURBINE REPLACEMENT | PROJECT # 137026073

TITLE: SINGLE LINE DIAGRAM

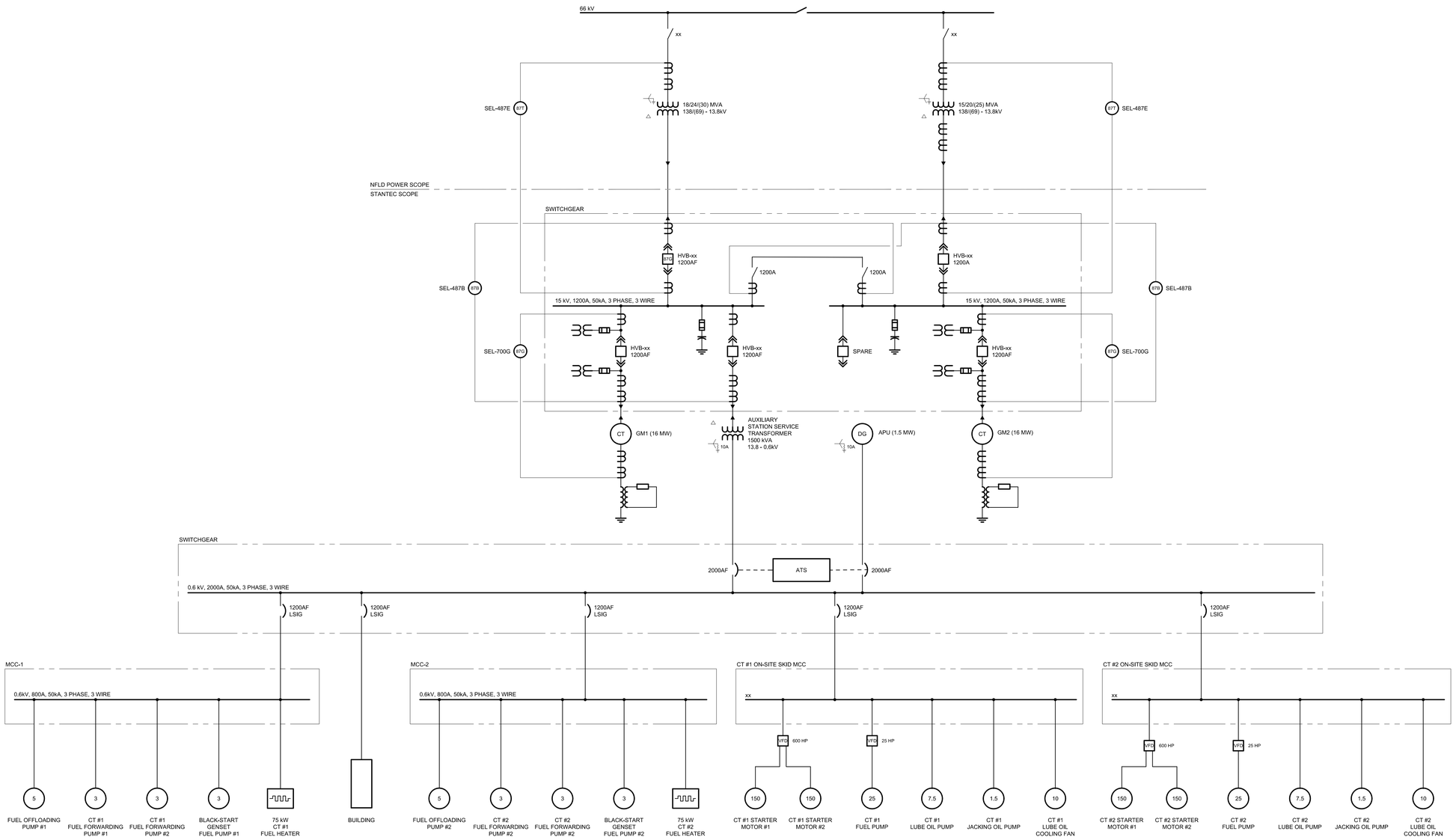
REV DESCRIPTION: ISSUED FOR REVIEW

DESIGNED: B. D. JONES | CHECKED: N/A

DRAWN: M. L. KENNEDY | APPROVED:

SCALE: NTS | DRAWING NUMBER: G-7102 1 OF 1 | REVISION: A

DATE: 2026/06/11



NOTES:

Stantec

DWG #	TITLE

REFERENCE DRAWINGS

REV	DATE	DESCRIPTION	APPROVED
A	JUL.03 2026	ISSUED FOR REVIEW	BDJ

REVISION HISTORY

NEWFOUNDLAND POWER
A FORTIS COMPANY

SITE: GREENHILL (GRH)

PROJECT: GAS TURBINE REPLACEMENT

PROJECT # 137026073

TITLE: SINGLE LINE DIAGRAM

REV DESCRIPTION: ISSUED FOR REVIEW

DESIGNED: B. D. JONES | CHECKED: N/A

DRAWN: M. L. KENNEDY | APPROVED:

SCALE: NTS | DRAWING NUMBER: G-7101 1 OF 1 | REVISION: A

DATE: 2026/06/11

Appendix F Cable Block Diagrams

COMBUSTION TURBINE ON-SKID
ELECTRICAL EQUIPMENT ROOM

COMBUSTION TURBINE
CONTROL PANEL

COMBUSTION TURBINE GENERATOR
PROTECTION PANEL

COMBUSTION TURBINE GENERATOR
TERMINAL BOX

12C#14 , TECK90, 600V (x2)
6F, OM4, ARMORED
4PR#16 , ACIC, SHLD, 300V
12C#14 , TECK90, 600V (x2)
6F, OM4, ARMORED
4C#8 , TECK90, 600V
4C#12 , TECK90, 600V

MAIN BUILDING -
CONTROL ROOM

TELECOM
CABINET

TO COMPRESSED AIR
RECEIVER DRAIN
SOLENOID VALVE

TO COMPRESSED AIR
PRESSURE TRANSMITTER

CAT 6, SF/UTP, ARMORED, 300V
2C#14 TECK90, 600V
1PR#16, ACIC, SHLD, 300V

12C#12 , TECK90, 600V
(x2)

COMBUSTION TURBINE
MANUAL SYNC/REMOTE
HMI PANEL

15kV SWITCHGEAR BUS
PROTECTION PANEL

CAT 6, SF/UTP, ARMORED, 300V

BALANCE OF PLANT (BOP)
PLC PANEL

4C#12 , TECK90, 600V
12C#12 , TECK90, 600V
(x2)
4C#12 , TECK90, 600V
12C#12 , TECK90, 600V
(x2)
4C#12 , TECK90, 600V
12C#12 , TECK90, 600V

GSU TRANSFORMER
PROTECTION PANEL

12C#12, TECK90, 600V (x3)
4C#8, TECK90, 600V (x3)
4C#12, TECK90, 600V
12C#12, TECK90, 600V
4C#8 , TECK90, 600V

12C#14, TECK90, 600V
FIRE ALARM
CONTROL PANEL

12C#14, TECK90, 600V
DOOR ACCESS /
SECURITY PANEL

12C#14, TECK90, 600V
HVAC CONTROL
PANEL

12C#14 , TECK90, 600V
12C#14 , TECK90, 600V

MAIN BUILDING -
SWITCHGEAR ROOM

15kV SWITCHGEAR

MAIN BUILDING -
ELECTRICAL ROOM

12C#14, TECK90, 600V
(x2)
12C#14, TECK90, 600V
(x2)
CAT 6, SF/UTP, ARMORED, 300V

MCC #1

MCC #2

600V AUTOMATIC
TRANSFER SWITCH

6F, OM4, ARMORED

12C#14, TECK90, 600V
12C#14, TECK90, 600V
6F, OM4, ARMORED

MAIN BUILDING -
BATTERY ROOM

BATTERY CHARGER

FUEL BUILDING

TO FUEL STORAGE
TANK LEVEL
TRANSMITTERS

COMBUSTION TURBINE
FUEL HEATER CONTROL
PANEL

12C#14 , TECK90, 600V
(x2)

1PR#16, ACIC, SHLD, 300V
(x2)

12C#14, TECK90, 600V

FUEL PIPING LEAK
DETECTION MODULE

TO LEAK SENSORS
1PR#16, ACIC, SHLD, 300V
(x4)

BALANCE OF PLANT
REMOTE I/O PANEL

1PR#16, ACIC, SHLD, 300V
(x2)
TO FUEL PUMP DISCHARGE
FLOW METERS

1PR#16, ACIC, SHLD, 300V
(x4)
TO FUEL PUMP SUCTION AND
DISCHARGE PRESSURE
TRANSMITTERS

2PR#16, ACIC, SHLD, 300V
TO FUEL RECIRCULATION
VALVE ELECTRO-PNEUMATIC
POSITIONERS

FUEL TRUCK
UNLOADING/OPERATOR
CONTROL STATION

12C#14 , TECK90, 600V
(x2)

1PR#16, ACIC,
SHLD, 300V
TO FUEL FILTER
DIFFERENTIAL
PRESSURE
TRANSMITTER

1PR#16, ACIC,
SHLD, 300V (x2)
TO FUEL
COALESCER
INSTRUMENTATION

1PR#16, ACIC,
SHLD, 300V
TO FUEL HEATER
OUTLET TEMPERATURE
TRANSMITTER

BLACK START GENSET AREA

BLACK START
GENSET

WASTE OIL TANK AREA

COMBUSTION TURBINE
WASTE OIL TANK
LEVEL/LEAK MONITORING
PANEL

NOTES:

1. ALL REQUIRED CABLING BETWEEN TURBINE VENDOR SUPPLIED PANELS IN THE ON-SKID ELECTRICAL EQUIPMENT ROOM AS WELL AS ALL REQUIRED CABLING BETWEEN THE TURBINE CONTROL PANEL AND ALL ON-SKID INSTRUMENTATION SHALL BE SUPPLIED AND FACTORY PRE-INSTALLED BY THE TURBINE VENDOR. ONLY OWNER SUPPLIED CABLES ARE SHOWN IN THIS DRAWING.

Stantec

DWG #	TITLE

REFERENCE DRAWINGS

REV	DATE	DESCRIPTION	APPROVED
A	JUN.19 2026	ISSUED FOR REVIEW	MRT

REVISION HISTORY

NEWFOUNDLAND POWER
A FORTIS COMPANY

SITE: WESLEYVILLE (WES)

PROJECT: GAS TURBINE REPLACEMENT
PROJECT # 137026073

TITLE: INSTRUMENT AND CONTROLS, AND PROTECTION AND CONTROL CABLE BLOCK DIAGRAM

REV. DESCRIPTION: ISSUED FOR REVIEW

DESIGNED: M. R. TOMPKINS
CHECKED: N/A
DRAWN: M. L. KENNEDY
APPROVED:

SCALE: NTS
DRAWING NUMBER: G-7113
1 OF 1
REVISION: A
DATE: 2026/06/11

COMBUSTION TURBINE ON-SKID ELECTRICAL EQUIPMENT ROOM

COMBUSTION TURBINE #2 ON-SKID ELECTRICAL EQUIPMENT ROOM

COMBUSTION TURBINE #1 TURBINE CONTROL PANEL

COMBUSTION TURBINE #1 GENERATOR PROTECTION PANEL

COMBUSTION TURBINE #1 GENERATOR TERMINAL BOX

COMBUSTION TURBINE #2 TURBINE CONTROL PANAEL

COMBUSTION TURBINE #2 GENERATOR PROTECTION PANEL

COMBUSTION TURBINE #2 GENERATOR TERMINAL BOX

12C#14, TECK 90, 600V (x2)

6F, 0M4, ARMORED (x2)

12C#14, TECK 90, 600V (x2)

12C#12, TECK 90, 600V

6F, 0M4, ARMORED

4C#12, TECK90, 600V

6F, 0M4, ARMORED

TELECOM CABINET

4PR#16, ACIC, SHLD, 300V

6F, 0M4, ARMORED

12C#14 , TECK90, 600V (x2)

4C#12, TECK90, 600V

4C#8, TECK90, 600V

12C#12 , TECK90, 600V

12C#12, TECK90, 600V

CAT 6, SF/UTP, ARMORED, 300V

12C#14, TECK90, 600V (x2)

6F, 0M4, ARMORED

4PR#16, ACIC, SHLD, 300V

4C#8, TECK90, 600V

15kV SWITCHGEAR #1 BUS PROTECTION PANEL

CAT 6, SF/UTP, ARMORED, 300V

BALANCE OF PLANT (BOP) PLC PANEL

CAT 6, SF/UTP, ARMORED, 300V

15kV SWITCHGEAR #2 BUS PROTECTION PANEL

COMBUSTION TURBINE #2 MANUAL SYNC/REMOTE HMI PANEL

COMBUSTION TURBINE #1 MANUAL SYNC/REMOTE HMI PANEL

2C#14, TECK90, 600V

TO COMPRESSED AIR RECEIVER DRAIN SOLENOID VALVE

TO COMPRESSED AIR PRESSURE TRANSMITTER

1PR#16, ACIC, SHLD, 300V

12C#14 , TECK90, 600V

FIRE ALARM CONTROL PANEL

12C#12, TECK90, 600V

12C#12 , TECK90, 600V

4C#12, TECK 90, 600V

12C#12, TECK 90, 600V (x2)

12C#12 , TECK90, 600V

DOOR ACCESS / SECURITY PANEL

GSU #2 TRANSFORMER PROTECTION PANEL

4C#12, TECK90, 600V

12C#12, TECK90, 600V (x2)

4C#8, TECK90, 600V (x2)

4C#12, TECK90, 600V

12C#12, TECK90, 600V (x2)

12C#12, TECK90, 600V

GSU #1 TRANSFORMER PROTECTION PANEL

HVAC CONTROL PANEL

4C#12, TECK 90, 600V

4C#12, TECK90, 600V (x3)

4C#8, TECK90, 600V (x3)

4C#12, TECK90, 600V

12C#12, TECK90, 600V

4C#8 , TECK90, 600V

12C#12, TECK90, 600V

4C#8 , TECK90, 600V

CONTROL BUILDING - CONTROL ROOM

12C#14, TECK 90, 600V (x2)

12C#14 , TECK90, 600V

15kV SWITCHGEAR #1

MCC #1

600V SWITCHGEAR

15kV SWITCHGEAR #2

MCC #2

BATTERY CHARGER

6F, OM4, ARMORED

12C#14, TECK90, 600V

12C#14, TECK90, 600V (x2)

6F, OM4, ARMORED

CONTROL BUILDING - ELECTRICAL ROOM

FUEL BUILDING

BLACK START GENSET AREA

WASTE OIL TANK AREA

TO FUEL STORAGE TANK LEVEL TRANSMITTERS

COMBUSTION TURBINE #1 FUEL HEATER CONTROL PANEL

12C#14 , TECK90, 600V (x2)

1PR#16, ACIC, SHLD, 300V (x4)

FUEL PIPING LEAK DETECTION MODULE

12C#14, TECK90, 600V

TO LEAK SENSORS

1PR#16, ACIC, SHLD, 300V (x6)

BALANCE OF PLANT REMOTE I/O PANEL

TO FUEL PUMP DISCHARGE FLOW METERS

1PR#16, ACIC, SHLD, 300V (x3)

TO FUEL PUMP SUCTION AND DISCHARGE PRESSURE TRANSMITTERS

1PR#16, ACIC, SHLD, 300V (x6)

TO FUEL RECIRCULATION VALVE ELECTRO-PNEUMATIC POSITIONERS

2PR#16, ACIC, SHLD, 300V

COMBUSTION TURBINE #2 FUEL HEATER CONTROL PANEL

12C#14 , TECK90, 600V (x2)

FUEL TRUCK UNLOADING/OPERATOR CONTROL STATION

12C#14 , TECK90, 600V (x2)

1PR#16, ACIC, SHLD, 300V (x2)

1PR#16, ACIC, SHLD, 300V (x4)

1PR#16, ACIC, SHLD, 300V (x2)

TO FUEL FILTER DIFFERENTIAL PRESSURE TRANSMITTER

TO FUEL COALESCER INSTRUMENTATION

TO FUEL HEATER OUTLET TEMPERATURE TRANSMITTER

BLACK START GENSET

COMBUSTION TURBINE #1 WASTE OIL TANK LEVEL/LEAK MONITORING PANEL

COMBUSTION TURBINE #2 WASTE OIL TANK LEVEL/LEAK MONITORING PANEL

NOTES:

1. ALL REQUIRED CABLING BETWEEN TURBINE VENDOR SUPPLIED PANELS IN THE ON-SKID ELECTRICAL EQUIPMENT ROOMS AS WELL AS ALL REQUIRED CABLING BETWEEN EACH TURBINE CONTROL PANEL AND ALL ON-SKID INSTRUMENTATION SHALL BE SUPPLIED AND FACTORY PRE-INSTALLED BY THE TURBINE VENDOR. ONLY OWNER SUPPLIED CABLES ARE SHOWN IN THIS DRAWING.

Stantec

DWG #	TITLE

REFERENCE DRAWINGS

REV	DATE	DESCRIPTION	APPROVED
A	JUN.19 2026	ISSUED FOR REVIEW	MRT

REVISION HISTORY

NEWFOUNDLAND POWER
A FORTIS COMPANY

SITE: GREENHILL (GRH)

PROJECT: GAS TURBINE REPLACEMENT

PROJECT # 137026073

TITLE: INSTRUMENT AND CONTROLS, AND PROTECTION AND CONTROL CABLE BLOCK DIAGRAM

REV. DESCRIPTION: ISSUED FOR REVIEW

DESIGNED: M.R.TOMPKINS

CHECKED: N/A

DRAWN: M. L. KENNEDY

APPROVED:

SCALE: NTS

DATE: 2026/06/11

DRAWING NUMBER: G-7112

1 OF 1

REVISION: A

Appendix G Network Architecture

COMBUSTION TURBINE ON-SKID ELECTRICAL EQUIPMENT ROOM (VENDOR SUPPLIED)

MAIN FUEL PUMP VFD

ALLEN-BRADLEY POWERFLEX 755

STARTER MOTORS VFD

ALLEN-BRADLEY POWERFLEX 755

ON-SKID MCC

ALLEN-BRADLEY E300 OVERLOAD RELAYS

ETHERNET/IP-DLR (TURBINE CONTROL NETWORK)

ETHERNET/IP-DLR (TURBINE CONTROL NETWORK)

TURBINE CONTROL PANEL

- AB GUARDLOGIX PLC RACK
- AB FLEX 5000 I/O RACK
- AB DYNAMIX 1444 VIBRATION MONITORS
- BASLER DECS-250 CGCM AVR AND AUTO-SYNC RELAY
- LOCAL HMI (SOLAR ACUITY)
- AB STRATIX 5800 MANAGED ETHERNET SWITCH

ETHERNET/IP (TURBINE CONTROL NETWORK)

TRIP SIGNALS

GENERATOR PROTECTION PANEL

- SEL-700G
- LOCK-OUT RELAY (86)

GENERATOR PT AND CT SIGNALS

GENERATOR TERMINAL BOX

- GENERATOR POTENTIAL AND CURRENT TRANSFORMER SECONDARY CONNECTIONS

TO ON-SKID FIELD INSTRUMENTATION

GENERATOR PT AND CT SIGNALS

MANUAL SYNC CONTROLS

GENERATOR PT AND CT SIGNALS

WASTE OIL TANK AREA

COMBUSTION TURBINE WASTE OIL TANK LEVEL / LEAK MONITORING PANEL

BLACK START GENSET AREA

BLACK START GENSET

FUEL BUILDING

BALLANCE OF PLANT (BOP) REMOTE I/O PANEL

ALLEN-BRADLEY FLEX 5000 I/O RACK

5094-AENSFPR | 5094-IF8 | 5094-IF8 | 5094-OF8 | 5094-IB16 | 5094-OB16

FUEL TANK UNLOADING / OPERATOR CONTROL STATION

- UNLOADING PUMP RUN / STOP SWITCH
- UNLOADING PUMP READY PILOT LIGHT
- UNLOADING RUNNING PILOT LIGHT
- FUEL STORAGE TANK LEVEL INDICATORS

FUEL SUPPLY INSTRUMENTATION

- PUMP SUCTION AND DISCHARGE PRESSURE
- PUMP DISCHARGE FLOW
- FILTER DIFFERENTIAL PRESSURE
- HEATER OUTLET TEMPERATURE
- COALESCER INSTRUMENTATION
- THREE-WAY / FUEL RECIRC VALVE

HEATER ALARM, HEATER RUNNING STATUS, PUMP RUNNING INTERLOCK

COMBUSTION TURBINE FUEL HEATER CONTROL PANEL

FUEL PIPING LEAK DETECTION MODULE

LEAK DETECTION ALARM, LEAK DETECTION INTERLOCK

FUEL STORAGE TANK LEVEL TRANSMITTERS

FUEL LEAK SENSORS

ETHERNET/IP (BOP CONTROL NETWORK)

FUEL TANK FLOAT SWITCH STATUSES FOR FUEL PUMP CONTROL

COMBUSTION TURBINE FUEL FORWARDING RUN REQUEST (TURBINE TO BOP) AND TURBINE IGNITION START PERMISSIVE (FUEL FORWARDING SYSTEM RUNNING AND HEALTHY; BOP TO TURBINE)

ALARMS

ETHERNET/IP (BOP CONTROL NETWORK)

TRANSFER TRIP AND BREAKER FAILURE SIGNALING

ETHERNET/IP (TURBINE CONTROL NETWORK)

COMBUSTION TURBINE MANUAL SYNC / REMOTE HMI PANEL (VENDOR SUPPLIED)

ALLEN-BRADLEY STRATIX 5800 MANAGED ETHERNET SWITCH

REMOTE HMI TERMINAL (SOLAR ACUITY)

ETHERNET/IP (TURBINE CONTROL NETWORK)

- MANUAL SYNC PUSHBUTTONS /SWITCHES
- MANUAL SYNC PILOT LIGHTS
- METERS
- SYNC SCOPE

BUS PT SIGNAL

15kV SWITCHGEAR BUS PROTECTION PANEL SEL-487B

BUS PT SIGNAL, GENERATOR BREAKER TRIP / BLOCK CLOSE SIGNALS AND GENERATOR BREAKER STATUS FEEDBACK

BUS PT SIGNAL, GENERATOR BREAKER CLOSE COMMAND AND GENERATOR BREAKER STATUS FEEDBACK

BREAKER FAILURE SIGNALING

GENERATOR STEP-UP (GSU) TRANSFORMER PROTECTION PANEL (BY OTHERS)

GSU PRIMARY WINDING CT SIGNALS (FOR TRANSFORMER DIFFERENTIAL PROTECTION), GSU BREAKER TRIP/BLOCK CLOSE SIGNALS AND GSU BREAKER STATUS FEEDBACK

BUS PT SIGNALS, BUS DIFFERENTIAL CT SIGNALS, BREAKER TRIP/BLOCK CLOSE SIGNALS AND BREAKER STATUS FEEDBACK

TELECOM CABINET (BY OTHERS)

- ENERGY CONTROL CENTER SCADA NETWORK EQUIPMENT

MODBUS TCP (BOP CONTROL NETWORK)

MODBUS TCP (BOP CONTROL NETWORK)

BALANCE OF PLANT (BOP) PLC PANEL

ALLEN-BRADLEY STRATIX 5800 MANAGED ETHERNET SWITCH

ETHERNET/IP (BOP CONTROL NETWORK)

HMI TERMINAL (AB PANELVIEW PLUS 7)

ETHERNET/IP (BOP CONTROL NETWORK)

MODBUS TCP (BOP CONTROL NETWORK)

ALLEN-BRADLEY CONTROLLOGIX PLC RACK (1756-A13)

1756-PA75 | 1756-L81E | 1756-ENBT/C | M/1756E-CPNET | 1756-IB16 | 1756-IB16 | 1756-IB16 | 1756-IB16 | 1756-OB16E | 1756-OB16E | 1756-IF8 | 1756-N2 | 1756-N2 | 1756-N2

COMPRESSED AIR PRESSURE TRANSMITTER

COMPRESSED AIR RECEIVER DRAIN VALVE (SOLENOID)

BUILDING ALARMS (FIRE, SECURITY, HVAC)

ALARMS

DNP3 (SCADA INTERFACE NETWORK)

MAIN BUILDING - CONTROL ROOM

MAIN BUILDING - SWITCHGEAR ROOM

MAIN BUILDING - BATTERY ROOM

MAIN BUILDING - ELECTRICAL ROOM

NGR MONITORING RELAY ALARM

ALARMS

MODBUS TCP (BOP CONTROL NETWORK)

FUEL PUMP FVNR STARTER CONTROLS

FUEL PUMP FVNR STARTER CONTROLS

15kV SWITCHGEAR

COMBUSTION TURBINE NGR

125VDC BATTERY CHARGER

600V AUTOMATIC TRANSFER SWITCH

MCC #1

MCC #2

NEUTRAL-GROUND CURRENT AND POTENTIAL SIGNALS

REMOTE START / STOP CONTROL

NOTES:

1. COMBUSTION TURBINE ON-SKID EQUIPMENT AND NETWORK TOPOLOGY IS PRELIMINARY AND BASED ON SOLAR PCM-130 PACKAGE. FINAL NETWORK TOPOLOGY TO BE CONFIRMED WITH SELECTED COMBUSTION TURBINE VENDOR. ALL EQUIPMENT AND PANELS LOCATED IN THE ON-SKID ELECTRICAL EQUIPMENT ROOM WILL BE SUPPLIED BY THE COMBUSTION TURBINE VENDOR.
2. REMOTE HMI AND MANUAL SYNC PANEL BASED ON SOLAR PCM-130 PACKAGE. FINAL CONFIGURATION TO BE CONFIRMED WITH SELECTED COMBUSTION TURBINE VENDOR.
3. SEPARATE ETHERNET (ALLEN-BRADLEY 1756-EN4TR) MODULES IN THE COMBUSTION TURBINE GUARDLOGIX PLC RACKS SHALL BE USED FOR:
   - 3.1. TURBINE CONTROL NETWORK (DLR)
   - 3.2. BOP INTERFACE
4. THE BALANCE OF PLANT PLC WILL IMPLEMENT THE FOLLOWING CONTROL AND MONITORING FUNCTIONS:
   - 4.1. FUEL STORAGE AND HANDLING SYSTEM CONTROLS AND MONITORING (FUEL STORAGE TANK LEVEL MONITORING, FUEL UNLOADING PUMPS, COMBUSTION TURBINE FUEL FORWARDING PUMPS, COMBUSTION TURBINE FUEL CONDITIONING SKID INTERFACES, BLACK START GENSET FUEL PUMPS, AND LEAK DETECTION).
   - 4.2. BLACK START GENSET AND 600V AUTOMATIC TRANSFER SWITCH MONITORING.
   - 4.3. FUEL FORWARDING COORDINATION WITH TURBINE START / STOP SEQUENSES VIA HARDWIRED I/O INTERFACES WITH THE TURBINE PLC.
   - 4.4. ADDITIONAL BALANCE OF PLANT ALARM MONITORING (COMPRESSED AIR, WASTE OIL STORAGE, BATTERY BANK, 15 kV SWITCHGEAR BUS PROTECTION, FIRE ALARM, SECURITY AND HVAC).
   - 4.5. TURBINE CONTROL SYSTEM DATA CONCENTRATION (ALARMING, METERING DATA, REMOTE CONTROL/SETPOINTS ETC.) FOR ENERGY CONTROL CENTER SCADA INTERFACE VIA ETHERNET/IP NETWORK INTERFACE WITH THE TURBINE PLC.
   - 4.6. TURBINE AND BALANCE OF PLANT INTERFACE WITH ENERGY CONTROL CENTER SCADA VIA DNP3. IT IS ASSUMED THAT THIS IS A DIRECT DNP3 OUTSTATION INTERFACE TO ENERGY CONTROL CENTER SCADA, VIA A FIREWALL IN THE TELECOM CABINET, AND SEPARATE FROM/ADDITIONAL TO THE TRANSMISSION SCADA RTU DNP3 OUTSTATION INTERFACE (SEE NOTE 5).
5. 138 kV SWITCHYARD PROTECTION & CONTROLS AND ASSOCIATED SCADA RTU (SEL AXION RTAC CONTROLLER) ARE BY OTHERS (NL POWER TRANSMISSION AND DISTRIBUTION GROUP). 138 kV SWITCHYARD PROTECTION & CONTROL AND SCADA INTERFACE NETWORKS WILL BE FULLY SEGREGATED FROM ALL COMBUSTION TURBINE AND BALANCE OF PLANT (GENERATION) RELATED NETWORKS. IT IS ASSUMED THAT GENERATION AND TRANSMISSION WILL SHARE THE SAME PHYSICAL NETWORK UPLINK INFRASTRUCTURE FROM THE STATION TO ENERGY CONTROL CENTER SCADA AND THAT THIS INFRASTRUCTURE WILL BE PROVIDED BY THE NL POWER TRANSMISSION AND DISTRIBUTION TELECOM GROUP.

LEGEND:

- ETHERNET (CAT 6)
- MULTIMODE FIBER (OM4)
- HARDWIRED I/O

Stantec

DWG #	TITLE

REFERENCE DRAWINGS

REV	DATE	DESCRIPTION	APPROVED
A	JUN.19 2026	ISSUED FOR REVIEW	MRT

REVISION HISTORY

NEWFOUNDLAND POWER
A FORTIS COMPANY

SITE: WESLEYVILLE (WES)

PROJECT: GAS TURBINE REPLACEMENT | PROJECT # 137026073

TITLE: CONTROL SYSTEM NETWORK ARCHITECTURE

REV DESCRIPTION: ISSUED FOR REVIEW

DESIGNED: M. R. TOMPKINS | CHECKED: N/A

DRAWN: M. L. KENNEDY | APPROVED:

SCALE: NTS | DRAWING NUMBER: G-7111 1 OF 1 | REVISION: A

DATE: 2026/06/11

COMBUSTION TURBINE #1 ON-SKID ELECTRICAL EQUIPMENT ROOM (VENDOR SUPPLIED)

MAIN FUEL PUMP VFD
ALLEN-BRADLEY POWERFLEX 755

STARTER MOTORS VFD
ALLEN-BRADLEY POWERFLEX 755

ON-SKID MCC
ALLEN-BRADLEY E300 OVERLOAD RELAYS

ETHERNET/IP-DLR (TURBINE CONTROL NETWORK)

ETHERNET/IP-DLR (TURBINE CONTROL NETWORK)

TURBINE CONTROL PANEL
- AB GUARDLOGIX PLC RACK
- AB FLEX 5000 I/O RACK
- AB DYNAMIX 1444 VIBRATION MONITORS
- BASLER DECS-250 CGCM AVR AND AUTO-SYNC RELAY
- LOCAL HMI (SOLAR ACUITY)
- AB STRATIX 5800 MANAGED SWITCH

TRIP SIGNALS

ETHERNET/IP (TURBINE CONTROL NETWORK)

GENERATOR PROTECTION PANEL
- SEL-700G
- LOCK-OUT RELAY (86)

GENERATOR TERMINAL BOX
- GENERATOR POTENTIAL AND CURRENT TRANSFORMER SECONDARY CONNECTIONS

GENERATOR PT AND CT SIGNALS

GENERATOR PT AND CT SIGNALS

TO ON-SKID FIELD INSTRUMENTATION

MANUAL SYNC CONTROLS

GENERATOR PT AND CT SIGNALS

COMBUSTION TURBINE #2 ON-SKID ELECTRICAL EQUIPMENT ROOM (VENDOR SUPPLIED)

MAIN FUEL PUMP VFD
ALLEN-BRADLEY POWERFLEX 755

STARTER MOTORS VFD
ALLEN-BRADLEY POWERFLEX 755

ON-SKID MCC
ALLEN-BRADLEY E300 OVERLOAD RELAYS

ETHERNET/IP-DLR (TURBINE CONTROL NETWORK)

ETHERNET/IP-DLR (TURBINE CONTROL NETWORK)

TURBINE CONTROL PANEL
- AB GUARDLOGIX PLC RACK
- AB FLEX 5000 I/O RACK
- AB DYNAMIX 1444 VIBRATION MONITORS
- BASLER DECS-250 CGCM AVR AND AUTO-SYNC RELAY

TRIP SIGNALS

ETHERNET/IP-DLR (TURBINE CONTROL NETWORK)

GENERATOR PROTECTION PANEL
- SEL-700G
- LOCK-OUT RELAY (86)

GENERATOR TERMINAL BOX
- GENERATOR POTENTIAL AND CURRENT TRANSFORMER SECONDARY CONNECTIONS

GENERATOR PT AND CT SIGNALS

GENERATOR PT AND CT SIGNALS

TO ON-SKID FIELD INSTRUMENTATION

ETHERNET/IP-DLR (GENERATOR PARALLELING INTERFACE NETWORK)

TRANSFER TRIP AND BREAKER FAILURE SIGNALLING

GENERATOR PT AND CT SIGNALS

MANUAL SYNC CONTROLS

FUEL BUILDING

BALLANCE OF PLANT (BOP) REMOTE I/O PANEL

ALLEN-BRADLEY FLEX 5000 I/O RACK

5094-AENSTPR | 5094-IF8 | 5094-IF8 | 5094-OF8 | 5094-IB16 | 5094-OB16

FUEL SUPPLY INSTRUMENTATION
- PUMP SUCTION AND DISCHARGE PRESSURE
- PUMP DISCHARGE FLOW
- FILTER DIFFERENTIAL PRESSURE
- HEATER OUTLET TEMPERATURE
- COALESCER INSTRUMENTATION
- THREE-WAY / FUEL RECIRC VALVES

FUEL TRUCK UNLOADING / OPERATOR CONTROL STATION
- UNLOADING PUMP RUN / STOP SWITCH
- UNLOADING PUMP READY PILOT LIGHT
- UNLOADING RUNNING PILOT LIGHT
- FUEL STORAGE TANK LEVEL INDICATORS

HEATER ALARM, HEATER RUNNING STATUS, PUMP RUNNING INTERLOCK

COMBUSTION TURBINE #1 FUEL HEATER CONTROL PANEL
- HEATER ALARM
- HEATER RUNNING STATUS
- PUMP RUNNING INTERLOCK

BLACK START GENSET AREA

BLACK START GENSET

HEATER ALARM, HEATER RUNNING STATUS, PUMP RUNNING INTERLOCK

COMBUSTION TURBINE #2 FUEL HEATER CONTROL PANEL
- HEATER ALARM
- HEATER RUNNING STATUS
- PUMP RUNNING INTERLOCK

REMOTE START / STOP COMMAND, GENERATOR READY FOR LOAD STATUS FEEDBACK, AND FUEL TANK FLOAT SWITCH STATUSES FOR FUEL PUMP CONTROL

LEAK DETECTION ALARM, LEAK DETECTION INTERLOCK

FUEL PIPING LEAK DETECTION MODULE
- LEAK DETECTION ALARM
- LEAK DETECTION INTERLOCK

MODBUS TCP (BOP CONTROL NETWORK)

FUEL STORAGE TANK LEVEL TRANSMITTERS

FUEL LEAK SENSORS

ETHERNET/IP (BOP CONTROL NETWORK)

COMBUSTION TURBINE #2 FUEL FORWARDING RUN REQUEST (TURBINE TO BOP) AND TURBINE IGNITION START PERMISSIVE (FUEL FORWARDING SYSTEM RUNNING AND HEALTHY; BOP TO TURBINE)

ETHERNET/IP (TURBINE CONTROL NETWORK)

ETHERNET/IP (BOP CONTROL NETWORK)

ETHERNET/IP (TURBINE CONTROL NETWORK)

TRANSFER TRIP AND BREAKER FAILURE SIGNALING

ETHERNET/IP (BOP CONTROL NETWORK)

BALANCE OF PLANT (BOP) PLC PANEL

ETHERNET/IP (BOP CONTROL NETWORK)

ALLEN-BRADLEY STRATIX 5800 MANAGED ETHERNET SWITCH

ETHERNET/IP (BOP CONTROL NETWORK)

HMI TERMINAL (AB PANELVIEW PLUS 7)

MODBUS TCP (BOP CONTROL NETWORK)

ETHERNET/IP (BOP CONTROL NETWORK)

MODBUS TCP (BOP CONTROL NETWORK)

ALLEN-BRADLEY CONTROLLOGIX PLC RACK (1756-A13)

1756-PA75 | 1756-L81E | MV156E-MNETC | MV156E-DPNET | 1756-IB16 | 1756-IB16 | 1756-IB16 | 1756-IB16 | 1756-OB16E | 1756-OB16E | 1756-IF8 | 1756-N2 | 1756-N2 | 1756-N2

COMBUSTION TURBINE #1 MANUAL SYNC / REMOTE HMI PANEL (VENDOR SUPPLIED)

ALLEN-BRADLEY STRATIX 5800 MANAGED ETHERNET SWITCH

REMOTE HMI TERMINAL (SOLAR ACUITY)

ETHERNET/IP (TURBINE CONTROL NETWORK)

- MANUAL SYNC PUSHBUTTONS/ SWITCHES
- MANUAL SYNC PILOT LIGHTS
- METERS
- SYNC SCOPE

COMBUSTION TURBINE #2 MANUAL SYNC / REMOTE HMI PANEL (VENDOR SUPPLIED)

ALLEN-BRADLEY STRATIX 5800 MANAGED ETHERNET SWITCH

REMOTE HMI TERMINAL (SOLAR ACUITY)

ETHERNET/IP (TURBINE CONTROL NETWORK)

- MANUAL SYNC PUSHBUTTONS/ SWITCHES
- MANUAL SYNC PILOT LIGHTS
- METERS
- SYNC SCOPE

TELECOM CABINET (BY OTHERS)
- ENERGY CONTROL CENTER SCADA NETWORK EQUIPMENT

DNP3 (SCADA INTERFACE NETWORK)

COMPRESSED AIR PRESSURE TRANSMITTER

COMPRESSED AIR RECEIVER DRAIN VALVE (SOLENOID)

BUILDING ALARMS (FIRE, SECURITY, HVAC)

ALARMS

BUS PT SIGNAL

GENERATOR STEP-UP (GSU) TRANSFORMER #1 PROTECTION PANEL (BY OTHERS)

15kV SWITCHGEAR BUS #1 PROTECTION PANEL SEL-487B

TRANSFER TRIP AND BREAKER FAILURE SIGNALING

GENERATOR STEP-UP (GSU) TRANSFORMER #2 PROTECTION PANEL (BY OTHERS)

BREAKER FAILURE SIGNALING

15kV SWITCHGEAR BUS #2 PROTECTION PANEL SEL-487B

NEUTRAL - GROUND CURRENT AND POTENTIAL SIGNALS

NGR MONITORING RELAY ALARM

COMBUSTION TURBINE #1 FUEL FORWARDING RUN REQUEST (TURBINE TO BOP) AND TURBINE IGNITION START PERMISSIVE (FUEL FORWARDING SYSTEM RUNNING AND HEALTHY; BOP TO TURBINE)

MAIN BREAKER AND BLACK START GENSET BREAKER TRIP / CLOSE CONTROLS, MAIN BREAKER AND BLACK START GENSET BREAKER STATUS FEEDBACK, AND MAIN BREAKER LINE UNDER VOLTAGE STATUS FEEDBACK

GSU #1 PRIMARY WINDING CT SIGNALS (FOR TRANSFORMER DIFFERENTIAL PROTECTION), GSU #1 BREAKER TRIP/BLOCK CLOSE SIGNALS AND GSU #1 BREAKER STATUS FEEDBACK

BREAKER FAILURE SIGNALING

CONTROL BUILDING - CONTROL ROOM

CONTROL BUILDING - ELECTRICAL ROOM

BUS PT SIGNAL, GENERATOR BREAKER TRIP / BLOCK CLOSE SIGNALS AND GENERATOR BREAKER STATUS FEEDBACK

BUS PT SIGNAL, GENERATOR BREAKER CLOSE COMMAND AND GENERATOR BREAKER STATUS FEEDBACK

BUS PT SIGNALS, BUS DIFFERENTIAL CT SIGNALS, BREAKER TRIP/BLOCK CLOSE SIGNALS AND BREAKER STATUS FEEDBACK

BUS PT SIGNALS, GENERATOR BREAKER CLOSE COMMAND AND GENERATOR BREAKER STATUS FEEDBACK

GSU #2 PRIMARY WINDING CT SIGNALS (FOR TRANSFORMER DIFFERENTIAL PROTECTION), GSU #2 BREAKER TRIP/BLOCK CLOSE SIGNALS AND GSU #2 BREAKER STATUS FEEDBACK

BUS PT SIGNALS, BUS DIFFERENTIAL CT SIGNALS, BREAKER TRIP/BLOCK CLOSE SIGNALS AND BREAKER STATUS FEEDBACK

BUS PT SIGNAL

BUS PT SIGNALS, BUS DIFFERENTIAL CT SIGNALS, BREAKER TRIP/BLOCK CLOSE SIGNALS AND BREAKER STATUS FEEDBACK

ALARMS

125VDC BATTERY CHARGER

FUEL PUMP FVNR STARTER CONTROLS

MCC #1

FUEL PUMP FVNR STARTER CONTROLS

MCC #2

600V SWITCHGEAR

15kV SWITCHGEAR #1

COMBUSTION TURBINE #1 NGR

15kV SWITCHGEAR #2

COMBUSTION TURBINE #2 NGR

NEUTRAL - GROUND CURRENT AND POTENTIAL SIGNALS

NGR MONITORING RELAY ALARM

WASTE OIL TANK AREA

ALARMS

COMBUSTION TURBINE #1 WASTE OIL TANK LEVEL/LEAK MONITORING

ALARMS

COMBUSTION TURBINE #2 WASTE OIL TANK LEVEL/LEAK MONITORING

NOTES:

1. COMBUSTION TURBINE ON-SKID EQUIPMENT AND NETWORK TOPOLOGY IS PRELIMINARY AND BASED ON SOLAR PCM-130 PACKAGE. FINAL NETWORK TOPOLOGY TO BE CONFIRMED WITH SELECTED COMBUSTION TURBINE VENDOR. ALL EQUIPMENT AND PANELS LOCATED IN THE ON-SKID ELECTRICAL EQUIPMENT ROOM WILL BE SUPPLIED BY THE COMBUSTION TURBINE VENDOR.
2. REMOTE HMI AND MANUAL SYNC PANEL BASED ON SOLAR PCM-130 PACKAGE. FINAL CONFIGURATION TO BE CONFIRMED WITH SELECTED COMBUSTION TURBINE VENDOR.
3. SEPARATE ETHERNET (ALLEN-BRADLEY 1756-EN4TR) MODULES IN THE COMBUSTION TURBINE GUARDLOGIX PLC RACKS SHALL BE USED FOR:
   - 3.1. TURBINE CONTROL NETWORK (DLR)
   - 3.2. BOP INTERFACE
   - 3.3. GENERATOR PARALLELING INTERFACE.
4. THE BALANCE OF PLANT PLC WILL IMPLEMENT THE FOLLOWING CONTROL AND MONITORING FUNCTIONS:
   - 4.1. FUEL STORAGE AND HANDLING SYSTEM CONTROLS AND MONITORING (FUEL STORAGE TANK LEVEL MONITORING, FUEL UNLOADING PUMPS, COMBUSTION TURBINE FUEL FORWARDING PUMPS, COMBUSTION TURBINE FUEL CONDITIONING SKID INTERFACES, BLACK START GENSET FUEL PUMPS, AND LEAK DETECTION).
   - 4.2. FUEL FORWARDING CO-ORDINATION WITH TURBINE START/STOP SEQUENCES VIA HARDWIRED I/O INTERFACES WITH EACH TURBINE PLC.
   - 4.3. BLACK START GENSET REMOTE START/STOP CONTROL AND ASSOCIATED 600V SWITCHGEAR BREAKER CONTROLS.
   - 4.4. ADDITIONAL BALANCE OF PLANT ALARM MONITORING (COMPRESSED AIR, WASTE OIL STORAGE, BATTERY BANK, 15 kV SWITCHGEAR BUS PROTECTION, FIRE ALARM, SECURITY AND HVAC).
   - 4.5. TURBINE CONTROL SYSTEM DATA CONCENTRATION (ALARMING, METERING DATA, REMOTE CONTROL/SETPOINTS ETC.) FOR ENERGY CONTROL CENTER SCADA INTERFACE VIA ETHERNET/IP NETWORK INTERFACE WITH THE TURBINE PLC.
   - 4.6. TURBINE AND BALANCE OF PLANT INTERFACE WITH ENERGY CONTROL CENTER SCADA VIA DNP3. IT IS ASSUMED THAT THIS IS A DIRECT DNP3 OUTSTATION INTERFACE TO ENERGY CONTROL CENTER SCADA, VIA A FIREWALL IN THE TELECOM CABINET, AND SEPARATE FROM/ADDITIONAL TO THE TRANSMISSION SCADA RTU DNP3 OUTSTATION INTERFACE (SEE NOTE 5).
5. 138 kV SWITCHYARD PROTECTION & CONTROLS AND ASSOCIATED SCADA RTU (SEL AXION RTAC CONTROLLER) ARE BY OTHERS (NL POWER TRANSMISSION AND DISTRIBUTION GROUP). 138 kV SWITCHYARD PROTECTION & CONTROL AND SCADA INTERFACE NETWORKS WILL BE FULLY SEGREGATED FROM ALL COMBUSTION TURBINE AND BALANCE OF PLANT (GENERATION) RELATED NETWORKS. IT IS ASSUMED THAT GENERATION AND TRANSMISSION WILL SHARE THE SAME PHYSICAL NETWORK UPLINK INFRASTRUCTURE FROM THE STATION TO ENERGY CONTROL CENTER SCADA AND THAT THIS INFRASTRUCTURE WILL BE PROVIDED BY THE NL POWER TRANSMISSION AND DISTRIBUTION TELECOM GROUP.

LEGEND:
- ETHERNET (CAT 6)
- MULTIMODE FIBER (OM4)
- HARDWIRED I/O

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DWG #	TITLE
REFERENCE DRAWINGS	

REV	DATE	DESCRIPTION	APPROVED
A	JUN.19 2026	ISSUED FOR REVIEW	MRT
REVISION HISTORY			

NEWFOUNDLAND POWER
A FORTIS COMPANY

SITE: GREENHILL (GRH)

PROJECT: GAS TURBINE REPLACEMENT

PROJECT # 137026073

TITLE: CONTROL SYSTEM NETWORK ARCHITECTURE

REV DESCRIPTION: ISSUED FOR REVIEW

DESIGNED: M. R. TOMPKINS | CHECKED: N/A

DRAWN: M. L. KENNEDY | APPROVED:

SCALE: NTS | DRAWING NUMBER: G-7110 | REVISION: A

DATE: 2026/06/11 | 1 OF 1

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Stantec is a global leader in sustainable engineering, architecture, and environmental consulting. The diverse perspectives of our partners and interested parties drive us to think beyond what's previously been done on critical issues like climate change, digital transformation, and future-proofing our cities and infrastructure. We innovate at the intersection of community, creativity, and client relationships to advance communities everywhere, so that together we can redefine what's possible.

Appendix B Opinion of Probable Capital Cost (OPCC)

WBS	Description	Major Characteristics	Unit	Final Quantity	Unit Labour Rate	Total Labour Cost	Material Unit Cost	Material Total Cost	Equipment Unit Cost	Equipment Total Cost	Other Unit Cost	Other Total Cost	Allowances	Overall Total ($)
	WESLEYVILLE COMBUSTION TURBINE		LS	1		$ 4,618,948		$ 34,623,680		$ 907,077		$ 16,221,124	$ 14,643,376	$ 71,014,205
1	MOBILIZATION AND SITE PREPARATION		LS	1		$ 123,795		$ 79,616		$ 72,170		$ -	$ 2,000	$ 277,581
1.1	Mobilization		LS	1		$ 71,656		$ 27,500		$ 47,873		$ -	$ -	$ 147,029
1.3	Temporary Construction Facilities (Contractor Mobilization)		LS	1		$ 8,376		$ -		$ 899		$ -	$ 2,000	$ 11,275
1.4	Site Fencing		LS	1		$ 8,591		$ 24,825		$ 4,298		$ -	$ -	$ 37,714
1.5	Laydown Areas		LS	1		$ 3,288		$ 7,291		$ 1,219		$ -	$ -	$ 11,799
1.6	Site Environmental Controls (erosion, sediment etc.)		LS	1		$ 7,288		$ 10,000		$ 599		$ -	$ -	$ 17,887
1.7	Temporary Site Lighting		LS	1		$ 1,822		$ -		$ 9,790		$ -	$ -	$ 11,612
1.8	Construction Access Control, Signage, and Traffic Management		LS	1		$ 22,774		$ 10,000		$ 7,491		$ -	$ -	$ 40,265
2	CIVIL WORKS		LS	1		$ 1,025,759		$ 760,017		$ 302,695		$ 32,352	$ -	$ 2,120,823
2.1	Clearing, Grubbing, Fill & Grading		LS	1		$ -		$ -		$ -		$ -	$ -	$ 303,117
2.2	Excavation & Earthworks		m3	984		$ -		$ -		$ -		$ -	$ -	$ 49,478
2.3	Restoration and drainage improvements		m3	757.4		$ 14,345		$ 30,299		$ 5,320		$ -	$ -	$ 49,964
2.4	Foundations		m3	367.1		$ 380,228		$ 270,229		$ 90,186		$ 4,512	$ -	$ 745,156
2.5	Building Modifications after CT Removal (WES)		LS	1		$ 302,654		$ 167,503		$ 76,774		$ -	$ -	$ 546,931
2.6	Fuel Forwarding Building		TN	8.61		$ -		$ -		$ -		$ -	$ -	$ 206,934
2.7	Trenches for Electrical Ductbanks		LS	1		$ -		$ -		$ -		$ -	$ -	$ 131,738
2.8	Tertiary Containment for Fuel Tanks		m3	408.1		$ -		$ -		$ -		$ -	$ -	$ 87,505
3	MECHANICAL		LS	1		$ 850,843		$ 30,636,857		$ 241,790		$ -	$ 4,852,400	$ 36,581,891
3.1	Equipment Receiving, Laydown & Inspection		LS	1		$ 35,378		$ -		$ 10,470		$ -	$ -	$ 45,848
3.2	Lift & Set CT in Place		LS	1		$ 21,227		$ 26,659,500		$ 31,674		$ -	$ 4,747,400	$ 31,459,801
3.3	CT Assembly & Alignment		LS	1		$ 70,756		$ 855,750		$ 20,940		$ -	$ -	$ 947,446
3.4	Lift, Set, & Install Air Inlet System (Some Assembly Required)		LS	1		$ 70,756		$ -		$ 20,940		$ -	$ -	$ 91,696
3.5	Lift, Set, & Install Exhaust Stack (Some Assembly Required)		LS	1		$ 21,227		$ 693,525		$ 6,282		$ -	$ 25,000	$ 746,034
3.6	Lift, Set, & Install Other CT Aux Systems (Some Assembly Required)		LS	1		$ 56,605		$ 105,398		$ 16,752		$ -	$ 5,000	$ 183,755
3.7	Lift, Set, & Install Fuel Tanks		LS	1		$ 37,147		$ 405,300		$ 17,012		$ -	$ 10,000	$ 469,459
3.8	Lift, Set, & Install Fuel Conditioning System		LS	1		$ 7,076		$ 34,367		$ -		$ -	$ -	$ 41,443
3.9	Fuel System Piping (piping & insulation) - Fuel Unloading to Fuel Tanks		LS	1		$ 113,210		$ 128,592		$ 33,504		$ -	$ 10,000	$ 285,307
3.10	Lift, Set, & Install Lube Oil System including piping		LS	1		$ 70,756		$ 98,051		$ 20,940		$ -	$ 5,000	$ 194,747
3.11	Lift, Set, & Install Black Start Diesel		LS	1		$ 7,076		$ 1,344,000		$ 2,094		$ -	$ 25,000	$ 1,378,170
3.12	Lift, Set, & Install Fire Protection Systems		LS	1		$ 7,076		$ -		$ 2,094		$ -	$ -	$ 9,170
3.13	Lift, Set, & Install Fuel Forwarding System		LS	1		$ 212,269		$ 240,487		$ 45,021		$ -	$ 25,000	$ 522,777
3.14	Access platforms, stairways, ladders, handrails for fuel tanks		LS	1		$ 35,378		$ 10,500		$ 10,470		$ -	$ -	$ 56,348
3.15	Fuel Forwarding Building Mechanical (HVAC, plumbing)		LS	1		$ 49,529		$ 45,150		$ 2,097		$ -	$ -	$ 96,777

WBS	Description	Major Characteristics	Unit	Final Quantity	Unit Labour Rate	Total Labour Cost	Material Unit Cost	Material Total Cost	Equipment Unit Cost	Equipment Total Cost	Other Unit Cost	Other Total Cost	Allowances	Overall Total ($)
3.16	Control Building Mechanical (HVAC, plumbing)		LS	1		$ 35,378		$ 16,237		$ 1,498		$ -	$ -	$ 53,113
4	ELECTRICAL		LS	1		$ 542,154		$ 2,588,474		$ 40,280		$ -	$ 90,000	$ 3,260,907
4.1	Power Equipment		LS	1		$ 45,690		$ 1,714,125		$ 15,134		$ -	$ 55,000	$ 1,829,949
4.2	Cabling		LS	1		$ 312,092		$ 510,490		$ 14,793		$ -	$ 35,000	$ 872,375
4.3	Cable Raceway		LS	1		$ 20,232		$ 33,642		$ 959		$ -	$ -	$ 54,833
4.4	125VDC System		LS	1		$ 16,041		$ 112,534		$ 3,272		$ -	$ -	$ 131,847
4.5	Building Services		LS	1		$ 18,617		$ 105,198		$ 882		$ -	$ -	$ 124,697
4.6	Grounding		LS	1		$ 105,156		$ 39,217		$ 4,984		$ -	$ -	$ 149,357
4.7	Heat Tracing		LS	1		$ 24,326		$ 73,269		$ 254		$ -	$ -	$ 97,849
5	INSTRUMENTATION		LS	1		$ 156,747		$ 513,581		$ 13,176		$ -	$ -	$ 683,505
5.1	Field Instrumentation		LS	1		$ 16,926		$ 237,956		$ 5,607		$ -	$ -	$ 260,489
5.2	Control Panels		LS	1		$ 3,319		$ 178,500		$ 1,099		$ -	$ -	$ 182,918
5.3	Cabling		LS	1		$ 62,381		$ 97,125		$ 2,957		$ -	$ -	$ 162,463
5.4	Control System Programming		LS	1		$ 74,121		$ -		$ 3,513		$ -	$ -	$ 77,634
6	PRE COMMISSIONING		LS	1		$ 102,364		$ 7,350		$ 31,410		$ -	$ 400,000	$ 541,125
6.1	Mechanical Completions		LS	1		$ 35,378		$ 5,250		$ 10,470		$ -	$ -	$ 51,098
6.2	Flushing & Cleaning of Systems (Fuel, lube, air, etc.)		LS	1		$ 35,378		$ 1,575		$ 10,470		$ -	$ -	$ 47,423
6.3	Electrical Completions		LS	1		$ 31,608		$ 525		$ 10,470		$ -	$ -	$ 42,603
6.4	Initial Fill of Fuel, Lube Oil		LS	1									$ 400,000	$ 400,000
7	COMMISSIONING & TESTING		LS	1		$ 523,596		$ -		$ 77,479		$ 400,000	$ -	$ 1,001,074
7.1	Commissioning & Testing		LS	1		$ 523,596		$ -		$ 77,479		$ 400,000	$ -	$ 1,001,074
8	STARTUP		LS	1		$ 35,378		$ -		$ 10,470		$ -	$ -	$ 45,848
8.1	Start Up and Systems Tuning		LS	1		$ 35,378		$ -		$ 10,470		$ -	$ -	$ 45,848
9	CLOSE OUT		LS	1		$ 91,690		$ 10,000		$ 50,616		$ -	$ -	$ 152,306
9.1	Demobilization		LS	1		$ 87,404		$ -		$ 49,206		$ -	$ -	$ 136,609
9.2	Site Restoration		LS	1		$ 4,287		$ 10,000		$ 1,411		$ -	$ -	$ 15,697
10	CONSTRUCTION INDIRECTS		LS	1		$ 115,223		$ 27,595		$ 60,796		$ 7,480,152	$ -	$ 7,683,766
10.1	CONTRACTOR INDIRECTS		LS	1		$ 115,223		$ 27,595		$ 60,796		$ 7,480,152	$ -	$ 7,683,766
11	PROJECT INDIRECTS		LS	1		$ 1,051,397		$ 190		$ 6,196		$ 8,308,620	$ 3,000	$ 9,369,404
12	ESCALATION		LS	1									$ -	$ -
13	CONTINGENCY		LS	1									$ 9,295,976	$ 9,295,976

WBS	Description	Major Characteristics	Unit	Final Quantity	Unit Labour Rate	Total Labour Cost	Material Unit Cost	Material Total Cost	Equipment Unit Cost	Equipment Total Cost	Other Unit Cost	Other Total Cost	Allowances	Overall Total ($)
	GREENHILL COMBUSTION TURBINE		LS	1		$ 6,730,019		$ 66,422,938		$ 1,435,743		$ 20,837,617	$ 26,647,519	$ 122,073,836
1	MOBILIZATION AND SITE PREPARATION		LS	1		$ 155,789		$ 118,313		$ 89,652		$ -	$ 11,000	$ 374,754
1.1	Mobilization		LS	1		$ 71,656		$ 27,500		$ 47,873		$ -	$ 5,000	$ 152,029
1.2	Temporary Construction Facilities (Contractor Mobilization)		LS	1		$ 26,235		$ -		$ 2,097		$ -	$ 6,000	$ 34,333
1.3	Site Fencing		LS	1		$ 17,136		$ 62,285		$ 8,673		$ -	$ -	$ 88,094
1.4	Laydown Areas		LS	1		$ 1,591		$ 3,528		$ 590		$ -	$ -	$ 5,709
1.5	Site Environmental Controls (erosion, sediment etc.)		LS	1		$ 10,932		$ 15,000		$ 899		$ -	$ -	$ 26,831
1.6	Temporary Site Lighting		LS	1		$ 5,466		$ -		$ 22,028		$ -	$ -	$ 27,494
1.7	Construction Access Control, Signage, and Traffic Management		LS	1		$ 22,774		$ 10,000		$ 7,491		$ -	$ -	$ 40,265
2	CIVIL WORKS		LS	1		$ 1,525,156		$ 1,463,326		$ 494,713		$ 70,944	$ -	$ 3,554,139
2.1	Clearing, Grubbing, Fill & Grading		LS	1		$ -		$ -		$ -		$ -	$ -	$ 422,559
2.2	Excavation & Earthworks		m3	3024		$ -		$ -		$ -		$ -	$ -	$ 116,455
2.3	Restoration and drainage improvements		m3	3399.2		$ 64,381		$ 135,971		$ 23,876		$ -	$ -	$ 224,228
2.4	Foundations		m3	714		$ 588,816		$ 476,736		$ 157,916		$ 8,424	$ -	$ 1,231,891
2.5	New Building Construction (GRH)		LS	1		$ 358,005		$ 477,960		$ 97,633		$ -	$ -	$ 933,598
2.6	Fuel Building (GRH)		TN	10.395		$ -		$ -		$ -		$ -	$ -	$ 221,046
2.7	Trenches for Electrical Ductbanks		LS	1		$ -		$ -		$ -		$ -	$ -	$ 294,581
2.8	Tertiary Containment for Fuel Tanks		m3	501.2		$ -		$ -		$ -		$ -	$ -	$ 109,782
3	MECHANICAL		LS	1		$ 1,483,758		$ 59,756,569		$ 413,948		$ -	$ 9,649,464	$ 71,303,738
3.1	Equipment Receiving, Laydown & Inspection		LS	1		$ 56,605		$ -		$ 16,752		$ -	$ -	$ 73,357
3.2	Lift & Set CT in Place		LS	1		$ 42,454		$ 53,319,000		$ 63,348		$ -	$ 9,494,464	$ 62,919,265
3.3	CT Assembly & Alignment		LS	1		$ 70,756		$ 1,709,400		$ 20,940		$ -	$ -	$ 1,801,096
3.4	Lift, Set, & Install Air Inlet System (Some Assembly Required)		LS	1		$ 141,512		$ -		$ 41,880		$ -	$ -	$ 183,393
3.5	Lift, Set, & Install Exhaust Stack (Some Assembly Required)		LS	1		$ 42,454		$ 1,387,050		$ 12,564		$ -	$ 50,000	$ 1,492,068
3.6	Lift, Set, & Install Other CT Aux Systems (Some Assembly Required)		LS	1		$ 56,605		$ 118,645		$ 16,752		$ -	$ 5,000	$ 197,002
3.7	Lift, Set, & Install Fuel Tanks		LS	1		$ 72,171		$ 752,850		$ 32,594		$ -	$ 40,000	$ 897,615
3.8	Fuel System Piping (piping & insulation) - Fuel Unloading to Fuel Tanks		LS	1		$ 155,664		$ 143,845		$ 46,068		$ -	$ 5,000	$ 350,577
3.9	Lift, Set, & Install Lube Oil System including piping		LS	1		$ 141,512		$ 139,065		$ 41,880		$ -	$ -	$ 322,458
3.10	Lift, Set, & Install Black Start Diesel		LS	1		$ 28,302		$ 1,344,000		$ 8,376		$ -	$ 25,000	$ 1,405,679
3.11	Lift, Set, & Install Fuel Forwarding System		LS	1		$ 403,310		$ 366,441		$ 86,902		$ -	$ 30,000	$ 886,652
3.12	Access platforms, stairways, ladders, handrails for fuel tanks		LS	1		$ 42,454		$ 42,000		$ 12,564		$ -	$ -	$ 97,018
3.13	Control Building Mechanical (HVAC, plumbing)		LS	1		$ 166,277		$ 286,717		$ 7,042		$ -	$ -	$ 460,036
3.14	Fuel Forwarding Building Mechanical (HVAC, plumbing)		LS	1		$ 42,454		$ 113,400		$ 1,798		$ -	$ -	$ 157,652
3.15	Lift, Set & Install Fuel Conditioning System		LS	1		$ 7,076		$ 34,157		$ 300		$ -	$ -	$ 41,532

WBS	Description	Major Characteristics	Unit	Final Quantity	Unit Labour Rate	Total Labour Cost	Material Unit Cost	Material Total Cost	Equipment Unit Cost	Equipment Total Cost	Other Unit Cost	Other Total Cost	Allowances	Overall Total ($)
3.16	Lift, Set, & Install Fire Protection Systems		LS	1		$ 14,151		$ -		$ 4,188		$ -	$ -	$ 18,339
4	**ELECTRICAL**		**LS**	**1**		**$ 798,004**		**$ 4,298,822**		**$ 60,559**		**$ -**	**$ 90,000**	**$ 5,247,386**
4.1	Power Equipment		LS	1		$ 71,245		$ 2,755,200		$ 23,600		$ -	$ 55,000	$ 2,905,044
4.2	Cabling		LS	1		$ 422,265		$ 1,099,461		$ 20,015		$ -	$ 25,000	$ 1,566,741
4.3	Cable Raceway		LS	1		$ 30,348		$ 47,901		$ 1,438		$ -	$ -	$ 79,687
4.4	125VDC System		LS	1		$ 16,041		$ 112,534		$ 3,272		$ -	$ -	$ 131,847
4.5	Building Services		LS	1		$ 31,880		$ 131,202		$ 1,511		$ -	$ -	$ 164,593
4.6	Grounding		LS	1		$ 200,870		$ 68,256		$ 9,521		$ -	$ 5,000	$ 283,648
4.7	Heat Tracing		LS	1		$ 25,356		$ 84,268		$ 1,202		$ -	$ 5,000	$ 115,825
5	**INSTRUMENTATION**		**LS**	**1**		**$ 258,825**		**$ 741,057**		**$ 22,254**		**$ -**	**$ 15,000**	**$ 1,037,136**
5.1	Field Instrumentation		LS	1		$ 30,755		$ 358,155		$ 10,187		$ -	$ 5,000	$ 404,097
5.2	Control Panels		LS	1		$ 4,425		$ 220,500		$ 1,466		$ -	$ -	$ 226,391
5.3	Cabling		LS	1		$ 142,887		$ 162,402		$ 6,773		$ -	$ 10,000	$ 322,061
5.4	Control System Programming		LS	1		$ 80,759		$ -		$ 3,828		$ -	$ -	$ 84,587
6	**PRE COMMISSIONING**		**LS**	**1**		**$ 163,783**		**$ 7,350**		**$ 50,256**		**$ -**	**$ 800,000**	**$ 1,021,389**
6.1	Mechanical Completions		LS	1		$ 56,605		$ 5,250		$ 16,752		$ -	$ -	$ 78,607
6.2	Flushing & Cleaning of Systems (Fuel, lube, air, etc.)		LS	1		$ 56,605		$ 1,575		$ 16,752		$ -	$ -	$ 74,932
6.3	Electrical Completions		LS	1		$ 50,573		$ 525		$ 16,752		$ -	$ -	$ 67,850
6.4	Initial Fill of Fuel, Lube Oil		LS	1									$ 800,000	$ 800,000
7	**COMMISSIONING & TESTING**		**LS**	**1**		**$ 792,469**		**$ -**		**$ 117,265**		**$ 800,000**	**$ -**	**$ 1,709,734**
7.1	Commissioning & Testing		LS	1		$ 792,469		$ -		$ 117,265		$ 800,000	$ -	$ 1,709,734
8	**STARTUP**		**LS**	**1**		**$ 70,756**		**$ -**		**$ 20,940**		**$ -**	**$ -**	**$ 91,696**
8.1	Start Up and Systems Tuning		LS	1		$ 70,756		$ -		$ 20,940		$ -	$ -	$ 91,696
9	**CLOSE OUT**		**LS**	**1**		**$ 148,419**		**$ 10,000**		**$ 81,550**		**$ -**	**$ -**	**$ 239,969**
9.1	Demobilization		LS	1		$ 139,846		$ -		$ 78,729		$ -	$ -	$ 218,575
9.2	Site Restoration		LS	1		$ 8,573		$ 10,000		$ 2,821		$ -	$ -	$ 21,394
10	**CONSTRUCTION INDIRECTS**		**LS**	**1**		**$ 136,337**		**$ 27,500**		**$ 74,379**		**$ 9,302,513**	**$ -**	**$ 9,540,729**
10.1	Contractor Indirects		LS	1		$ 136,337		$ 27,500		$ 74,379		$ 9,302,513	$ -	$ 9,540,729
11	**PROJECT INDIRECTS**		**LS**	**1**		**$ 1,196,723**		**$ -**		**$ 10,227**		**$ 10,664,160**	**$ 3,000**	**$ 11,874,110**
12	**ESCALATION**		**LS**	**1**									**$ -**	**$ -**
13	**CONTINGENCY**		**LS**	**1**									**$ 16,079,055**	**$ 16,079,055**

Appendix C Basis of Estimate (BOE)

Basis of Estimate (BOE) - Wesleyville and Greenhill Combustion Turbine Sites

A basis of estimate document to support two separate capital cost estimates for combustion turbine sites.

Stantec

Prepared for:
Newfoundland Power

Prepared by:
Mark MacNevin

Date:
September 28, 2026

Project/File:
137026073 - CT Class 3 Study

Stantec Consulting Ltd.

Revision Record

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Disclaimer

The conclusions in the Report titled Basis of Estimate (BOE) - Wesleyville and Greenhill Combustion Turbine Site are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

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Executive Summary

Newfoundland Power is advancing an initiative to replace aging combustion turbine facilities at the Greenhill and Wesleyville generating stations. The existing combustion turbine generators, installed between 1969 and 1975, have reached the end of their useful service lives and require replacement to maintain emergency generation capability, system reliability, and operational flexibility across the provincial electrical system. The proposed project will modernize both facilities through the installation of new liquid-fueled combustion turbine technology, associated balance-of-plant infrastructure, upgraded electrical systems, fuel storage and handling facilities, control systems, and supporting civil and structural works. At Greenhill, approximately 30 MW_e of new combustion turbine generation will be installed, while Wesleyville will receive approximately 15 MW_e of new generation capacity.

Stantec was retained by Newfoundland Power to complete an Association for the Advancement of Cost Engineering (AACE) International Class 3 engineering study and capital cost estimate to support project planning, regulatory approval submissions, and future investment decisions. The estimate was developed using approximately 10% engineering definition and incorporates preliminary design deliverables, quantity take-offs, historical project data, contractor productivity assumptions, and current market pricing. To improve confidence in the estimate, budgetary quotations were obtained for several major equipment packages including combustion turbines, medium-voltage switchgear, black-start generators, fuel tanks, and other key electrical and mechanical systems. A design allowance was also incorporated to account for remaining uncertainty associated with the current level of project development.

The estimated total overnight capital cost for the Wesleyville project is $71.0 million CAD, including project indirects and contingency. The estimated total overnight capital cost for the Greenhill project is $122.1 million CAD, including project indirects and contingency. Mechanical systems, including the combustion turbine packages and associated balance-of-plant equipment, represent the largest cost component at both sites and account for approximately half of the total project costs. Project indirect costs, construction indirects, owner's cost, commissioning, and contingency have been included to provide a comprehensive assessment of anticipated project expenditures. Escalation, AFUDC, and substation-related costs have been excluded from the overnight capital estimates and are expected to be addressed separately by Newfoundland Power as part of the overall business case evaluation.

Given the current volatility within the global combustion turbine market, the estimate includes a dedicated escalation allowance on combustion turbine equipment pricing to account for ongoing supply chain constraints, limited manufacturing capacity, extended lead times, and sustained demand for power generation equipment. This approach is intended to better reflect current market conditions and mitigate procurement risk associated with long-lead equipment.

To establish an appropriate contingency allowance and improve estimate reliability, Stantec completed independent Monte Carlo risk analyses for both the Greenhill and Wesleyville projects. The simulations evaluated uncertainties associated with quantities, unit pricing, equipment costs, market conditions, and project execution risks. Based on the results, a P90 contingency level was selected for both projects, representing a funding position with a 90% probability that final project costs will not exceed the estimated budget. The resulting contingencies are $16.1 million CAD (15.2%) for Greenhill and $9.3 million CAD (15.1%) for Wesleyville. This risk-based approach aligns with industry best practices and strengthens the overall confidence associated with the Class 3 estimate.

Acronyms / Abbreviations

Acronym / Abbreviation	Full Name
AACE	Association for the Advancement of Cost Engineering
AFUDC	Allowance for Funds used During Construction
CTG	Combustion Turbine Generators
EOR	Engineer of Record
GRH	Greenhill
IDC	Interest During Construction
NP	Newfoundland Power
PFD	Process Flow Diagrams
QRA	Quantitative Risk Analysis
SCADA	Supervisory Control and Data Acquisition
STS	Small Tools and Supplies
WES	Wesleyville

1 Project Description

Newfoundland Power (NP) is undertaking an initiative to replace aging combustion turbine generation facilities at its Greenhill (GRH) and Wesleyville (WES) generating stations. The existing combustion turbine generators (CTGs), originally installed between 1969 and 1975 have reached the end of their service lives and require replacement to maintain system reliability and emergency power generation capabilities.

The project involves the replacement of the existing generating assets with modern, liquid-fueled combustion turbine technology designed to provide dependable emergency generation and support the provincial electrical system during peak demand and contingency events. At GRH, the existing generating facility, building, and fuel storage infrastructure will be decommissioned and replaced with approximately 30 MW_e of new CTG, a new control building, upgraded electrical systems, and a modern fuel storage and handling facility. At WES, the existing turbine and fuel storage systems will be replaced with approximately 15 MW_e of new CTG and associated fuel storage system, while retaining and repurposing the existing powerhouse building.

The project includes comprehensive mechanical, electrical, instrumentation and control, civil, and structural upgrades at both sites. Key project components include new combustion turbines, black-start generators, fuel storage tanks with secondary containment systems, fuel handling and filtration equipment, switchgear, protection and control systems, communications and SCADA interfaces, site infrastructure improvements, foundations, drainage systems, fencing, access roads, and ancillary utility services.

As part of the development process, NP has engaged Stantec Consulting Ltd. (Stantec) to complete a Class 3 engineering study and cost estimate in accordance with the Association for the Advancement of Cost Engineering (AACE) Recommended Practice No. 18R-97. The study will support regulatory approval submissions and establish the technical, environmental, permitting, and cost basis for project implementation. Environmental assessment and permitting activities will be completed in accordance with applicable provincial and federal regulations, with a focus on managing environmental risks, modernizing fuel storage systems, reducing operational impacts, and ensuring long-term compliance with current industry standards.

Upon completion, the project will provide NP with modern, reliable, and environmentally compliant generation assets that enhance grid resiliency, improve operational flexibility, and support continued electrical service reliability for customers.

2 Estimate Classification

The Class 3 cost estimate has been developed based on an approximately 10% level of engineering design and follows the AACE Recommended Practice No. 18R-97 methodology for Class 3 estimates. At this stage of project development, the estimate is supported by preliminary engineering deliverables, including site layouts, process flow diagrams, general arrangements, single-line diagrams, and design basis documentation. To improve estimate accuracy and increase cost confidence, recent vendor budgetary quotations and market pricing were incorporated for several major equipment packages, including combustion turbines, switchgear, black-start generators, fuel tanks, and other key electrical and mechanical systems. These quotations provide a current market benchmark for the largest cost drivers within the project, while remaining scope elements were developed using discipline-specific quantity take-offs, historical project data, supplier budget pricing, and industry-standard estimating techniques. Stantec used a 5% added quantity value to account for the classification of estimate and design completed. This is to combat unknowns in the design process that typically arise as the level of detailed design gets completed. As a result, the estimate provides a robust planning-level assessment of the anticipated capital cost and is considered suitable for project evaluation, regulatory approvals, and investment decision-making.

The expected accuracy range for a Class 3 estimate in the process industry is typically -10% to -20% on the low side and +10% to +30% on the high side, depending on project complexity, site conditions, execution strategy, market conditions, and the quality of the underlying project definition. A Class 3 estimate is commonly associated with an AACE estimate suitable for budget approval and is often supplemented by Quantitative Risk Analysis (QRA), such as Monte Carlo simulation, to establish an appropriate contingency and improve confidence in the projected cost. As such, Stantec's opinion on the accuracy range on the estimate is +30%/-20% and completed a QRA to establish a defendable contingency to carry to achieve a P90 confidence on the capital costs presented.

3 Basis of Estimate Methodology

The following sections help define the overall methodology by the various scopes and level of engineering completed.

3.1 Labour

Labour costs for the estimate were developed using current applicable union collective agreements and associated wage schedules, including base wage rates, overtime provisions, payroll burdens, statutory costs, and other contractual obligations. Given the remote locations of both the GRH and WES sites and the limited availability of local skilled trades resources, the estimate assumes that the 50% of construction personnel will be sourced from outside the immediate project areas and will therefore require lodging, travel allowances, and subsistence payments for the duration of their site assignments. These additional workforce accommodation costs have been incorporated into the estimate to reflect anticipated project execution conditions and to provide a realistic assessment of total construction labour expenditures.

Construction crews were developed using typical contractor crew compositions based on industry-standard labour makeups for the required union trades, including electricians, instrument technicians, pipefitters, boilermakers, ironworkers, carpenters, labourers, equipment operators, and associated supervisory personnel. Labour resources were assigned to both direct construction activities, such as installation of mechanical, electrical, civil, and structural infrastructure, as well as indirect activities including site services, temporary facilities, commissioning support, safety management, quality control, material handling, and construction supervision. This crew-based estimating approach provides a practical representation of how the project would be executed in the field and supports the development of a Class 3 estimate with an appropriate level of confidence for project planning and regulatory review purposes.

Labour rates are based on a fifty (50) hour work week of five (5) days per week, ten (10) hours per day.

Included in the labour costs is a $5/hr allowance for small tools and supplies (STS). This would include items such as hammers, nails, nuts, bolts, etc. that are used throughout the job site that are too fine-scale to be estimated at this stage of a project. This allowance typically ranges from $3-$10 depending on the complexity of the project.

Crew makeup and hourly costs are listed in Table 1 below:

Table 1. Crew Composition

Crew	Cost	Composition
Concrete Crew	$626.33	1 IronWorker (IW), 1 Labourer (Lab), 4 Concrete (Conc) Lab, 1 Carpenter (Carp), 1 Conc Foreman
Rebar Crew	$643.45	5 IW, 1 IW Apprentice, 1 IW Foreman
Formwork Crew	$740.96	5 Carp, 1 Lab, 1 IW, 1 Carp Foreman
Heavy Mechanical	$672.56	4 IW, 1 IW Foreman, 2 Millwright (MW)
Earthworks Crew	$138.19	1 Operator (OP), 0.5 Lab

3.2 Equipment

Equipment costs were developed using industry-standard construction equipment rental databases, with monthly rental rates converted to productive hourly ownership and operating rates for estimating purposes. The calculated equipment rates include fuel, lubricants, and other routine consumables required for operation, providing a comprehensive all-in operating cost for each equipment type. Major construction equipment considered in the estimate includes cranes, excavators, loaders, dozers, compactors, aerial work platforms, generators, welding equipment, and material handling equipment necessary to support civil, structural, mechanical, and electrical construction activities.

Equipment requirements were allocated to specific construction activities based on the planned means and methods of execution and the anticipated crew compositions. Equipment maintenance, routine repairs, and associated downtime allowances are assumed to be included within the contractor's indirect costs and overhead structure and have therefore not been separately identified within the estimate. In addition, no additional allowance has been included for standby equipment rates or extended equipment idle periods beyond those inherent within normal construction productivity assumptions. This approach reflects typical contractor utilization practices and is considered appropriate for a Class 3 estimate prepared at the current stage of project definition

3.3 Materials

Material costs were primarily developed using Stantec's internal estimating databases, which contain historical pricing information derived from comparable projects, industry benchmarks, supplier budget pricing, and recent market experience. These database values were used to establish unit rates for bulk materials, commodities, building systems, and common construction components across the civil, structural, mechanical, electrical, and instrumentation disciplines. To improve estimate accuracy and reflect current market conditions, internal pricing was supplemented with recent vendor quotations and budget pricing for major permanent equipment packages, including combustion turbines, switchgear, generators, fuel tanks, and other high-value specialty equipment.

Material quantities were developed from the available preliminary engineering deliverables and design basis information, with unit pricing applied in accordance with the level of project definition associated with a Class 3 estimate. Freight, handling, and contractor procurement considerations were incorporated where appropriate to reflect the remote nature of the project sites. This combination of historical cost data and current vendor-supplied pricing provides a balanced estimating approach that leverages both proven project experience and market-based equipment costs, resulting in an estimate with an appropriate level of confidence for project planning, regulatory review, and investment decision-making.

Materials that were quoted include the following:

1. Medium Voltage Switchgear.
2. Diesel Generator.
3. CTG and associated equipment.
4. Fuel Heater.
5. Compressed Air System.

6. Exhaust Stack.
7. Fuel Polishing Equipment.
8. HVAC Equipment.
9. Waste Oil Tank.
10. Ball Valves.
11. Centrifugal Pump Assembly.
12. HV Cables.
13. Fuel Tanks.

Materials that were used from recently completed projects

1. Low Voltage Switchgear.
2. Station Service Transformer.
3. MCC.
4. Cabling.
5. Piping.
6. Concrete Supply.
7. Aggregate Supply.

3.4 Project Directs

Project Directs include all tasks directly related to the completion of the project by the Contractor. This would include those direct costs of performing the work as well as the indirect costs such as staffing, trailers, profit & overhead, etc. Each section below provides a brief description of the Project Direct costs.

3.4.1 Site Preparation

The site preparation scope includes all work necessary to establish a safe, accessible, and construction-ready site prior to the start of major civil, mechanical, and electrical activities. This work typically begins with clearing and grubbing, which involves the removal of vegetation, trees, brush, stumps, unsuitable materials, and other surface obstructions within the project footprint. Environmental controls are then installed and maintained to ensure compliance with regulatory requirements and environmental permits, including erosion and sediment control measures, and stormwater management features. The scope also includes mobilization, covering the transportation of personnel, equipment, temporary facilities, construction materials, and support services to the site, as well as the establishment of laydown areas, and contractor construction offices. In addition, temporary and permanent utility hookups are provided as

required to support construction and future operations, including electrical power, water, communications, sewer, and other site services.

Site Preparation activities have been assumed to be completed outside of peak bird nesting season in NL which is May 1 – August 31. To avoid additional costs and reduced productivity, the clearing and grubbing is predominantly occurring in April.

3.4.2 Civil/Structural

Civil and structural quantities were developed from the preliminary engineering completed as part of the Design Basis Memorandum, including the site layout drawings, general arrangement drawings, process flow diagrams, equipment layouts, and discipline-specific design criteria. Quantities for earthworks were derived from the proposed site grading concepts, equipment footprints, building locations, roadways, fuel storage areas, and required site expansions at both facilities. At GRH, quantities were based on the creation of a new turbine and control building area at the upper site elevation, including excavation of the existing hill crest, cut-and-fill operations, access roads, equipment pads, fuel tank containment systems, and site fencing. At WES, quantities were developed based on the proposed eastern site expansion required to accommodate the new combustion turbine and fuel storage infrastructure, including granular fill placement to raise the extension area to match existing grades. Geotechnical assumptions documented in the Design Basis Memorandum were used to estimate excavation volumes, unsuitable material removal, imported granular materials, and foundation excavation requirements.

Structural quantities were developed from the preliminary building arrangements and major equipment layouts identified during the study. Concrete quantities were estimated for combustion turbine foundations, exhaust stack foundations, transformer pads, black-start generator foundations, fuel tank foundations, containment structures, and building foundations based on conceptual sizing and vendor information available at the time of estimating. Structural steel quantities were derived from preliminary building dimensions and assumed framing systems for the new Greenhill control building, fuel buildings, and modifications to the existing Wesleyville facility. Additional quantities were developed for stairs, access platforms, equipment supports, fencing and gates, fuel tank containment berms, drainage infrastructure, septic systems, and miscellaneous site civil works. The resulting quantities reflect the approximately 10% project definition level associated with an AACE Class 3 estimate and are considered appropriate for planning, budgeting, and regulatory approval purposes

3.4.3 Mechanical

Mechanical quantities were developed from the process flow diagrams (PFDs), preliminary general arrangement drawings, site layouts, and the mechanical design basis established for the combustion turbine facilities. Major equipment quantities were derived directly from the defined project scope, assuming two (2) 15 MW_e CTGs at GRH, one (1) 15 MW_e CTG at WES, black-start generators at each site, fuel storage systems, fuel handling and filtration equipment, compressed air systems, waste oil systems, de-ionized water systems, HVAC equipment, potable water systems, and building utility services. Fuel system quantities were based on the preliminary fuel process configurations, including forwarding pumps, heaters, monitoring and coalescing skids, fuel piping, valves, instrumentation interfaces, and truck offloading facilities. Tank quantities were established from the design basis requirement for four (4) 100,000 L tanks at GRH and two (2) 100,000 L tanks at WES, along with associated containment systems and ancillary equipment.

Bulk mechanical material quantities, including piping, valves, insulation, heat tracing, supports, and miscellaneous accessories, were developed using preliminary equipment layouts and conceptual routing assumptions based on the available design information. Building mechanical quantities were derived from the proposed facility layouts and identified requirements for potable water, plumbing, HVAC, washroom facilities, heating equipment, and ventilation systems. Where vendor data was available, such as for the combustion turbines and associated balance-of-plant systems, equipment dimensions and utility requirements were utilized to improve quantity accuracy. Quantities were developed consistent with the approximately 10% engineering definition expected for an AACE Class 3 estimate and reflect the level of detail available during the study phase.

3.4.3.1 CT Escalation

Due to ongoing volatility and supply constraints within the combustion turbine market, an escalation allowance has been applied to account for pricing risk over the project development and procurement period. While US Bureau of Labor and Statistics producer price indices indicate that turbine-related equipment costs have increased by approximately 8% annually on average over the past five years, market experience and recent vendor budget pricing suggest that escalation for the specific combustion turbine technology being considered has significantly exceeded broader industry trends. ((n.d.), 2026)[i] Factors such as limited manufacturing capacity, extended lead times, global demand for power generation equipment, and supply chain pressures have contributed to higher cost growth for this equipment class. As a result, a conservative escalation rate of 16% has been carried in the estimate to better reflect current market conditions and mitigate the risk of future price increases prior to procurement.

3.4.4 Electrical and Instrumentation

The Electrical includes the installation, testing, and commissioning of all electrical systems required to support power generation, plant operations, and grid interconnection. This scope encompasses the generator electrical systems, auxiliary transformers, medium- and low-voltage switchgear, motor control centers, protective relaying, grounding and bonding systems, station service power distribution, lighting, and lightning protection. Electrical work also includes the installation of cable trays, conduits, power and control cabling, terminations, electrical equipment foundations interfaces, and connections to the plant control and monitoring systems. The scope further includes utility interconnection facilities, electrical testing, energization support, and commissioning activities to verify system performance and compliance with applicable codes, standards, and utility requirements. Together, these electrical systems enable the safe, reliable, and efficient operation of the combustion turbine facility and its associated balance-of-plant equipment.

Electrical quantities were developed from the preliminary single-line diagrams, site layouts, cable block diagrams, network architecture drawings, and the electrical design basis documentation prepared for both generating stations. Major equipment quantities were established directly from the defined system configuration, including new 15 kV switchgear lineups, station service transformers, standby generators, motor control centres, DC battery systems, UPS systems, protection and control equipment, grounding systems, lighting systems, panel boards, and associated power distribution infrastructure. Quantities for major electrical equipment were refined using vendor budget pricing and equipment selections developed during the AACE Class 3 study.

Cable quantities were estimated using preliminary equipment locations and conceptual routing between generating units, switchgear, transformers, control buildings, MCCs, and ancillary systems. Cable tray, buried conduit, precast trenching, grounding conductor, and duct bank quantities were developed from the site layouts and building arrangements. Electrical building service quantities, including lighting, receptacles, heating systems, fire alarm systems,

access control, and exterior lighting, were established using preliminary building footprints and anticipated operational requirements. The estimate also incorporated quantities associated with black-start capability, station service distribution, and interfaces with the existing substations. Quantities reflect the level of definition available at the study stage and are consistent with the requirements of an AACE Class 3 estimate.

Instrumentation, control, and protection system quantities were developed from the control system network architecture diagrams, cable block diagrams, process flow diagrams, equipment counts, and the Instrumentation & Control and Protection & Control design basis sections of the study. The estimate was based on vendor-supplied turbine control and generator protection systems for each combustion turbine, including two complete turbine control systems at Greenhill and one at Wesleyville. Additional quantities were developed for balance-of-plant control systems, operator interface stations, SCADA integration, communications equipment, network infrastructure, and associated field instrumentation.

Field instrumentation quantities were established from the identified mechanical process requirements, including fuel storage tanks, fuel transfer systems, fuel filtration and heating equipment, compressed air systems, waste oil systems, and auxiliary utility systems. Control cabling, fibre optic infrastructure, communication networks, marshalling equipment, and system interfaces were developed using preliminary architecture drawings and equipment layouts. Protection and control quantities included bus differential protection systems, neutral grounding resistor systems, switchgear protection, transformer interfaces, relaying, annunciation, and integration with Newfoundland Power's System Control Centre SCADA systems. Quantities were determined using equipment counts and conceptual interconnection requirements and reflect the level of engineering definition appropriate for an approximately 10% design and an AACE Class 3 estimate.

3.4.5 Commissioning

Commissioning costs were developed based on the commissioning strategy defined for the installation of the new combustion turbine generating facilities at GRH and WES. A significant portion of the commissioning scope is associated with the combustion turbine packages themselves, and vendor-supplied commissioning services have been incorporated directly into the estimate using recent budgetary quotations received from the combustion turbine supplier. These vendor services are assumed to include factory and site technical support, equipment inspections, start-up assistance, functional testing, performance verification, operator training support, and achievement of commercial operation criteria for the combustion turbine generator systems.

The estimate also includes a dedicated contractor commissioning team responsible for planning, coordinating, executing, and documenting commissioning activities across all project disciplines. Commissioning labour was developed using a combination of commissioning managers, commissioning specialists, electrical and mechanical superintendents, field technicians, and union trade personnel required to support testing, troubleshooting, punch list completion, system turnover, and operational readiness activities. Trade support was included for mechanical, electrical, instrumentation, and civil deficiencies identified during pre-commissioning and commissioning, as well as for energization, loop checks, calibration, equipment run testing, and integrated system testing.

In addition to contractor and vendor resources, the estimate assumes active participation by NP as the Owner, as well as the Owner's Engineer of Record (EOR) throughout the commissioning process. Owner and EOR representation are assumed for commissioning planning, design clarification, witnessing of critical tests, review of commissioning documentation, deficiency management, operational acceptance, and final turnover activities. The commissioning estimate therefore reflects a collaborative execution model involving vendor specialists, contractor commissioning

personnel, supporting construction trades, Owner representatives, and EOR personnel to ensure safe start-up, successful system integration, and reliable operation of the new generating facilities. The Owner and EOR Commissioning costs are found in Project Indirects.

3.4.6 Contractor Indirects

Contractor indirect costs were included in the estimate to account for the temporary facilities, management resources, support personnel, and services required to execute the work, but which cannot be directly assigned to a specific construction activity. These costs were developed using a crew-based approach and are proportional to the anticipated project duration, workforce size, and overall construction complexity. Contractor indirects include project management, site supervision, construction management, field engineering, quality assurance and quality control, health and safety management, environmental compliance, planning and scheduling, document control, procurement support, warehouse and materials management, security, and administrative personnel required throughout the execution phase.

The estimate also includes temporary construction facilities and site services such as mobilization and demobilization, temporary offices, utilities, communications systems, construction power, water and sanitary services, site security, access control, signage, temporary fencing, laydown and storage areas, environmental protection measures, and temporary lighting. In addition, contractor indirects include small tools and consumables, routine equipment maintenance, vehicle usage, material handling, general site logistics, and support required to coordinate the activities of multiple trades and subcontractors throughout the project lifecycle.

Given the remote nature of the GRH and WES sites, the estimate also assumes that contractor indirect costs will include workforce accommodation requirements, travel coordination, and camp or lodging administration for personnel requiring subsistence. These indirect costs are intended to represent a realistic project execution environment and provide the necessary infrastructure and management systems to safely and efficiently deliver the project. Contractor indirects were developed separately from direct labour, material, equipment, and major subcontract costs and are considered appropriate for an AACE Class 3 estimate prepared at approximately 10% design completion.

3.4.6.1 Overhead and Profit

Overhead and Profit for the contractor is intended to cover various overhead costs such as corporate legal, executives, non-billable staff and infrastructure, and a profit margin. It was assumed for this project that a larger contractor would be required to execute this work and as such a higher overhead rate would be required. The blended rate was assumed at 20% on all project direct costs, excluding bonding and the CTG purchase. It is assumed that the CTG purchase will be performed by NP.

3.4.6.2 Contractor Bonding and Insurance

Contractor bonding and insurance was estimated to be 1% of all direct costs excluding CTG purchases.

3.5 Project Indirects

Project indirect costs encompass expenditures that are necessary to plan, design, permit, and manage a project but are not directly associated with physical construction activities. These costs typically include owner's costs, such as project management, procurement support, legal services, stakeholder engagement, and internal administration required to

advance the project. Engineering and design costs are also included and cover activities such as preliminary and detailed design, technical studies, preparation of construction documents, tendering support, and construction-phase services. Permitting and regulatory fees form another key component and may include environmental approvals, municipal and provincial permits, application fees, and compliance monitoring requirements. In addition, indirect costs include site investigations required to support design and construction, such as topographic and boundary surveys, utility locates, and geotechnical investigations to characterize subsurface conditions, assess foundation requirements, and identify potential geotechnical risks. Collectively, these indirect costs are essential for project development, risk mitigation, regulatory compliance, and successful project execution.

3.5.1 Owner's Costs

Owner's costs represent the expenditures incurred directly by the project owner to initiate, oversee, and administer the project throughout its lifecycle. These costs are separate from construction and engineering expenses and typically include project management, administrative support, procurement and contract management, legal services, financial oversight, stakeholder and Indigenous engagement, public consultation, and internal labor required to support project development and execution. Owner's costs also include travel expenses, land acquisition or easement negotiations, insurance, utility coordination, and contingency allowances for project administration. These activities are essential to ensuring effective governance, decision-making, risk management, and coordination among project stakeholders, and are often incurred from project conception through commissioning and closeout.

3.5.2 Consultant Costs

Consultant costs include the professional services required to plan, design, assess, and support the implementation of a project. These costs typically encompass engineering, environmental, regulatory, and technical advisory services provided throughout the project lifecycle. Consultant activities may include feasibility studies, site assessments, surveys, geotechnical investigations, environmental studies, detailed design, preparation of drawings and specifications, cost estimating, risk assessments, permitting support, and stakeholder consultation. During procurement and construction, consultant costs may also include tendering assistance, construction administration, site inspections, quality assurance reviews, and commissioning support. These services provide the technical expertise necessary to develop a safe, reliable, and constructible design, manage project risks, ensure regulatory compliance, and support successful project execution.

Consultant costs were estimated based on a bottom-up approach for each site.

3.5.3 Contingency

A Monte Carlo risk analysis was completed to evaluate the potential range of project costs and quantify the impact of uncertainty on the estimate. Monte Carlo simulation is a probabilistic modeling technique that assesses the combined effect of multiple cost risks and estimating uncertainties by repeatedly calculating project costs using thousands of iterations. For each iteration, key cost elements are varied within defined ranges based on their anticipated level of uncertainty, producing a distribution of potential project outcomes rather than a single deterministic value.

The analysis allows project stakeholders to better understand the likelihood of achieving specific cost targets and provides insight into the level of contingency required to achieve a desired confidence level. By incorporating uncertainty associated with quantities, unit rates, equipment pricing, market conditions, schedule impacts, and other

project-specific risks, the simulation generates a range of potential project costs along with associated probability metrics such as P50, P80, and P90 values. These results support risk-informed decision making and provide a more comprehensive understanding of potential cost exposure.

Separate Monte Carlo analyses were performed for the Greenhill and Wesleyville projects to account for the unique scope, site conditions, risk profiles, and cost structures associated with each development. Conducting the analyses independently ensured that project-specific uncertainties were appropriately represented and that risk outcomes accurately reflected the characteristics of each estimate. Uncertainties and ranges were determined based on Stantec's industry experience and the manner in which the estimate was progressed.

For an AACE Class 3 estimate, which is typically developed with a level of project definition sufficient to support budget authorization and project control decisions, the Monte Carlo analysis strengthens estimate reliability by providing a quantitative assessment of cost uncertainty and contingency requirements. Rather than relying solely on deterministic contingency allowances, the simulation evaluates the cumulative impact of individual estimating uncertainties and project risks, resulting in a more defensible and transparent estimate. This approach aligns with industry's best practices for risk-informed estimating and improves confidence that the estimate appropriately reflects the range of potential outcomes expected at the AACE Class 3 level of project definition.

The results of the Monte Carlo simulations have been documented within the Design Basis Report, including the key assumptions, uncertainty ranges, confidence levels, and recommended contingency allowances. These findings were used to inform the development of the project estimates, establish risk-adjusted project budgets, and support decision-making by providing a comprehensive assessment of potential cost variability under a range of foreseeable project conditions.

GRH contingency has been carried at $16,079,055.28 (15.17%) representing a P90 contingency.

WES contingency has been carried at $9,295,975.94 (15.06%) representing a P90 contingency.

The P90 estimate represents the cost value at which there is a 90% likelihood that the final project cost will not be exceeded. The associated contingency is intended to account for the combined effects of identified risks, estimating uncertainty, quantity variability, market conditions, and other potential cost fluctuations modeled during the Monte Carlo simulation. Selecting a P90 funding level provides a high degree of budget confidence, with only a 10% probability that actual project costs will exceed the estimated amount. As such, the P90 result is often used to support capital funding decisions where a conservative budget position is desired, and budget overruns must be minimized.

4 Design Maturity

As part of estimate development, a focused effort was undertaken to advance overall design maturity and reduce uncertainty associated with key cost drivers. Elements previously assessed at conceptual level were further developed wherever practical through additional engineering definition, refinement of quantities, constructability considerations, and improved scope delineation. Particular emphasis was placed on higher-value and higher-risk components, where supplier and contractor budget quotations were actively solicited to validate pricing assumptions and better reflect current market conditions. The incorporation of vendor input, updated technical requirements, and enhanced design information has improved confidence in both quantities and unit rates, reducing reliance on conceptual estimating techniques. These activities have strengthened the basis of estimate, and when combined with a 10% design maturity,

align with the requirements outlined for an initial AACE Class 3 estimate. This results in a more robust and defensible cost estimate suitable for project planning, risk evaluation, and investment decision making

The following Table 2 and Table 3 define the Class 4 and Class 3 requirements as a high-level summary.

Table 2. AACE Class 4 Definition

CLASS 4 ESTIMATE	
Description: Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval. Typically, engineering is from 1% to 15% complete, and would comprise at a minimum the following: plant capacity, block schematics, indicated layout, process flow diagrams (PFDs) for main process systems, and preliminary engineered process and utility equipment lists. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Process flow diagrams (PFDs) issued for design. 1% to 15% of full project definition. **End Usage:** Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage.	**Estimating Methodology:** Class 4 estimates generally use factored estimating methods such as equipment factors, Lang factors, Hand factors, Chilton factors, Peters-Timmerhaus factors, Guthrie factors, the Miller method, gross unit costs/ratios, and other parametric and modeling techniques. **Expected Accuracy Range:** Typical accuracy ranges for Class 4 estimates are -15% to -30% on the low side, and +20% to +50% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Screening, top-down, feasibility (pre-feasibility for metals processes), authorization, factored, pre-design, pre-study.

Table 2b – Class 4 Estimate

Table 3. AACE Class 3 Definition

CLASS 3 ESTIMATE	
Description: Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists. Remedial action plan resulting from HAZOPs is identified. **Maturity Level of Project Definition Deliverables:** Key deliverable and target status: Piping and instrumentation diagrams (P&IDs) issued for design. 10% to 40% of full project definition. **End Usage:** Class 3 estimates are typically prepared to support full project funding requests, and become the first of the project phase control estimates against which all actual costs and resources will be monitored for variations to the budget. They are used as the project budget until replaced by more detailed estimates. In many owner organizations, a Class 3 estimate is often the last estimate required and could very well form the only basis for cost/schedule control.	**Estimating Methodology:** Class 3 estimates generally involve more deterministic estimating methods than conceptual methods. They usually involve predominant use of unit cost line items, although these may be at an assembly level of detail rather than individual components. Factoring methods may be used to estimate less-significant areas of the project. **Expected Accuracy Range:** Typical accuracy ranges for Class 3 estimates are -10% to -20% on the low side, and +10% to +30% on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination). Ranges could exceed those shown if there are unusual risks. **Alternate Estimate Names, Terms, Expressions, Synonyms:** Budget, scope, sanction, semi-detailed, authorization, preliminary control, concept study, feasibility (for metals processes) development, basic engineering phase estimate, target estimate.

Table 2c – Class 3 Estimate

The following table has been created to define the current stage of design maturity (in green) across the Stantec preliminary design phase.

S – Started

P – Preliminary

NR – Not Required

C - Completed

Table 4. AACE Design Maturity Matrix

Technical Deliverable	Class 4 (1–15%)	Class 3 (10–40%)
Block Flow Diagrams – N/A	C	C
Equipment Datasheets	P	C
Equipment Lists – Electrical	P	C
Equipment Lists – Mechanical / Process	P	C
Heat & Material Balances	C	C
Process Flow Diagrams (PFDs)	C	C
Utility Flow Diagrams (UFDs) – N/A	C	C

Design Specifications / Basis of Design	S/P	C
Technical Deliverable	**Class 4 (1–15%)**	**Class 3 (10–40%)**
Electrical One-Line Diagrams	S/P	C
General Equipment Arrangement Drawings	S/P	C
Instrument List	S/P	C
Piping & Instrumentation Diagrams (P&IDs)	S/P	C
Plot Plans / Facility Layouts	S/P	C
Civil / Site / Structural / Architectural Drawings	S/P	P
Demolition Plans and Drawings	S/P	P
Erosion Control Plans and Drawings	S/P	P
Fire Protection & Life Safety Drawings	S/P	P
Electrical Schedules	NR/S	P
Instrument & Control Schedules	NR/S	P
Instrument Datasheets	NR/S	P
Piping Schedules	NR/S	P (Large Bore)
Piping Discipline Drawings	NR/S	S/P
Spare Parts Listings	NR	P
Electrical Discipline Drawings	NR	S/P
Facility Emergency Communication Drawings	NR	S/P
Information Systems / Telecom Drawings	NR	S/P
Instrumentation / Control System Drawings	NR	S/P
Mechanical Discipline Drawings	NR	S/P

5 Construction Execution Strategy and Sequence

For both sites, the project is assumed to be a standard Design-Bid-Build methodology with the exception of the CTG purchases being performed by NP and free issued to the selected contractor. The designer will work with NP to procure the CTGs and detail the design accordingly for procurement. This will reduce the design uncertainty in the bidding process for contractors.

The expected phased construction is outlined below:

- Phase 1 – Engineering and Procurement: detailed engineering, permitting, geotechnical investigations and procurement.
- Phase 2 – Site Preparation: clearing, grubbing, temporary facilities and access roads.
- Phase 3 – Civil Construction: excavation, foundations, underground services and equipment pads.
- Phase 4 – Structural and Building Construction: control building, electrical building and structural steel erection.
- Phase 5 – Mechanical Installation: combustion turbine, auxiliary systems, fuel gas systems and fire protection.
- Phase 6 – Electrical Installation: GSU transformer, protection systems, cabling, grounding and SCADA.
- Phase 7 – Interconnection Works: switchyard construction and transmission tie-ins.
- Phase 8 – Commissioning and Startup: testing, synchronization, performance testing and reliability run.

6 Capital Cost Breakdown

The following tables outline the findings of the study for the GRH and WES AAC Class 3 estimates.

Table 5. Wesleyville Cost Breakdown

WBS	Description	Overall Total ($ 2026 CAD)
	WESLEYVILLE COMBUSTION TURBINE	**$ 71,014,205**
1	MOBILIZATION AND SITE PREPARATION	$ 277,581
2	CIVIL WORKS	$ 2,120,823
3	MECHANICAL	$ 36,581,891
4	ELECTRICAL	$ 3,260,907
5	INSTRUMENTATION	$ 683,505
6	PRE COMMISSIONING	$ 541,125
7	COMMISSIONING & TESTING	$ 1,001,074
8	STARTUP	$ 45,848
9	CLOSE OUT	$ 152,306
10	CONSTRUCTION INDIRECTS	$ 7,683,766
11	PROJECT INDIRECTS	$ 9,369,404
12	ESCALATION (*CT Market Escalation included under Mechanical*)	$ -
13	CONTINGENCY	$ 9,295,976

Table 6. Greenhill Cost Breakdown

WBS	Description	Overall Total ($ 2026 CAD)
	GREENHILL COMBUSTION TURBINE	**$ 122,073,836**
1	MOBILIZATION AND SITE PREPARATION	$ 374,754
2	CIVIL WORKS	$ 3,554,139
3	MECHANICAL	$ 71,303,738
4	ELECTRICAL	$ 5,247,386
5	INSTRUMENTATION	$ 1,037,136
6	PRE COMMISSIONING	$ 1,021,389
7	COMMISSIONING & TESTING	$ 1,709,734
8	STARTUP	$ 91,696
9	CLOSE OUT	$ 239,969
10	CONSTRUCTION INDIRECTS	$ 9,540,729
11	PROJECT INDIRECTS	$ 11,874,110
12	ESCALATION (*CT Market Escalation included under Mechanical*)	$ -
13	CONTINGENCY	$ 16,079,055

7 Estimate Assumptions, Clarifications, and Exclusions

Key elements of the estimate are outlined in the following subsections and are to be review in conjunction with the AACE Class 3 estimates.

7.1 Estimate Assumptions

Estimate assumptions include the following:

- Labour is readily available to perform the work.
- Four-year delivery for combustion turbines.
- Public Utilities Board approval in early 2027.
- Overnight costs based on 2026 pricing.
- Quotations are valid representations of actual procurement costs.

7.2 Escalation and Currency

Escalation other than CT escalation allowance has been excluded from this estimate and is being calculated by NP to be added to the business case.

Currency is Canadian Dollars (CAD).

7.3 AFUDC

Allowance for Funds Used During Construction (AFUDC) represents financing costs incurred during construction and capitalized into the asset.

AFUDC has been excluded from this estimate and is being calculated by NP to be added to the business case.

7.4 Substation Costs

Substation costs have been excluded from this estimate and is being calculated by NP to be added to the business case.

7.5 Exclusions

Standard with this level of estimate, the follow exclusions have been made:

- Taxes (HST).

- Additional legal costs associated with contract negotiations not covered in Overhead.
- Delays in manufacturing or delivery of major components.
- General project escalation (exception: combustion turbines).
- AFUDC / Financing costs.
- Substation Costs.
- Project offsetting costs.
- Any Indigenous or Rightsholder engagement or associated costs.
- Strike or demonstration interruptions.
- Severe weather impacts.
- Force majeure and pandemic impacts.

8 Risks and Opportunities

This estimate does provide several risks and opportunities to the overall project and how it could be executed. It is recommended that these risks and opportunities be looked at through various sensitivity analyses.

- Escalation: depending on the rate chosen, this may fluctuate drastically as seen through the pandemic.
- AFUDC: Utilities and developers have varying degrees of costs for these
- Combustion Turbine delivery time: the delivery time of the project could cause additional escalation costs not currently accounted for. Alternatively, a faster timeline would potentially reduce escalation costs.
- Work Schedule: While the current schedule is estimated on a 5-day per week at 10-hr per day basis, the project does have the ability to put a back-shift or work weekends to achieve schedule. These costs are not included in the estimate and may have an impact depending on the schedule saved vs baseline as indirect costs are predominantly time based.
- Contracting Methodology: While a standard Design-Bid-Build methodology has been taken for this estimate, the project may choose to pre-qualify a preferred contractor and engage them in the early design of the project to allow for construction efficiencies to be found through the design process. This is referred to as early contractor engagement. The owner maintains a contract separately with both the designer and the contractor but pairs them together as a team. Alternatively, there are other progressive models such as an Alliance model which may be used to team contractors with designers and have one governing contract from the owner where painshare and gainshare can be used as motivational tools to perform.

9 References

U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Turbine and Turbine Generator Set Units Manufacturing (PCU333611333611), retrieved from Federal Reserve Economic Data (FRED), accessed at https://fred.stlouisfed.org/series/PCU333611333611

With every community, we redefine what's possible.

Stantec is a global leader in sustainable engineering, architecture, and environmental consulting. The diverse perspectives of our partners and interested parties drive us to think beyond what's previously been done on critical issues like climate change, digital transformation, and future-proofing our cities and infrastructure. We innovate at the intersection of community, creativity, and client relationships to advance communities everywhere, so that together we can redefine what's possible.

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Appendix D Monte Carlo Assessment

CONTINGENCY REPORT
August 5, 2026

CLIENT: Newfoundland Power
PROJECT: WESLEYVILLE COMBUSTION TURBINE
Stantec Project Number 1370260073
Report prepared by: Keir Fiske

Project estimate updated August 4, 2026
File Name: "Wesleyville CT_Capex_2026-06-26_R6_@RISK RUN-20260805"

@RISK (AACE 40R-08 Probabilistic method)

The @Risk Monte Carlo probabilistic simulation performed 100,000 iterations on the estimate values. The input analysis for this redesign effort was elicited from each of the individual discipline groups for the most representative data on each design focus, these captured values were incorporated for the respective estimate range accuracy and confidence. For the Indirect and Soft cost components, a range of -5% and +30% with 85% confidence was utilized.

The @Risk Monte Carlo Simulation resulted in a P90 Value of $71,014,205.14 and report is attached. The result of this analysis is a determined P90 contingency value of $9,295,975.94 when compared to the estimated value before contingency ($61,718,229.20). The attached output reports provide additional details of the summary below.

@Risk Monte Carlo Simulation Method for determining contingency

@Risk Report P10 Total	$64,769,721.00	P10 Mean_Contingency	$3,051,491.80
		4.94% @Risk _ Run @ ~9:50 am Aug 05, 2026	
@Risk Report P50 Total	$67,661,601.57	P50 Mean_Contingency	$5,943,372.37
		9.63% @Risk _ Run @ ~9:50 am Aug 05, 2026	
@Risk Report P90 Total	$71,014,205.14	P90 Mean_Contingency	$9,295,975.94
		15.06% @Risk _ Run @ ~9:50 am Aug 05, 2026	

AACE 119R-21

Contingency Calculation following the AACE 119R-21 recommended practice was not utilized. With this project being at the FEL3 gate stage and the understood confidence in the values being high, specifically with Quoted CT Equipment, the 119R-21 method does not provide the correct representative values to use for recommending contingency value determination.

AACE 119R-21 Method for determining contingency

	Parameters Used
Estimate Class	
Technology Level	
Complexity Level	

Updated : NOT UPDATED

Table 4 from section 2.6 of AACE 119R-21

High p90	Tech	Complexity L	M	H	Low p10	Tech	Complexity L	M	H	Median p50	Tech	Complexity L	M	H
Class 3	L	3%	11%	20%	Class 3	L	-3%	-9%	-14%	Class 3	L	2%	8%	13%
	M	8%	16%	31%		M	-7%	-12%	-19%		M	6%	11%	19%
	H	13%	23%	37%		H	-10%	-16%	-21%		H	9%	15%	21%
Class 4	L	15%	26%	40%	Class 4	L	-12%	-17%	-22%	Class 4	L	10%	16%	22%
	M	22%	35%	53%		M	-15%	-21%	-26%		M	14%	20%	27%
	H	30%	46%	70%		H	-19%	-24%	-29%		H	18%	25%	32%
Class 5	L	37%	56%	85%	Class 5	L	-21%	-26%	-31%	Class 5	L	21%	28%	36%
	M	48%	73%	114%		M	-25%	-30%	-35%		M	25%	33%	42%
	H	63%	97%	158%		H	-28%	-33%	-38%		H	30%	38%	48%

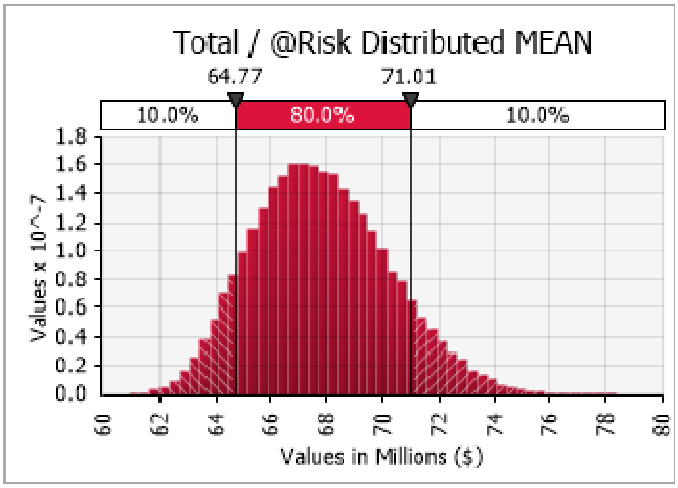
Table 4 – RAND Model-Based Accuracy and Contingency Values

P90 (With x1.2 critical event multiplier) =		*Potential MAX*	$0.00
P50 = (With x1.2 critical event multiplier)		***Most Probable***	**$0.00**
P10 =		*Potential MIN*	$0.00

WESLEYVILLE COMBUSTION TURBINE

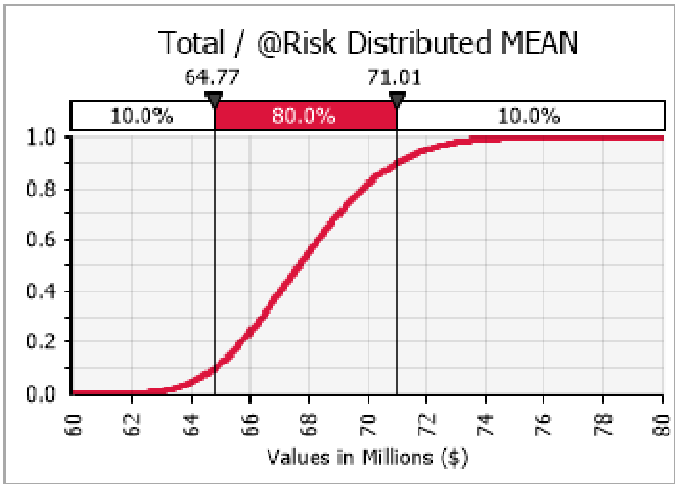
Total / @Risk Distributed MEAN - '@ Risk Contingency'!J90

Report: Compact Output Report
Performed By: kfiske
Date: Wednesday, August 5, 2026



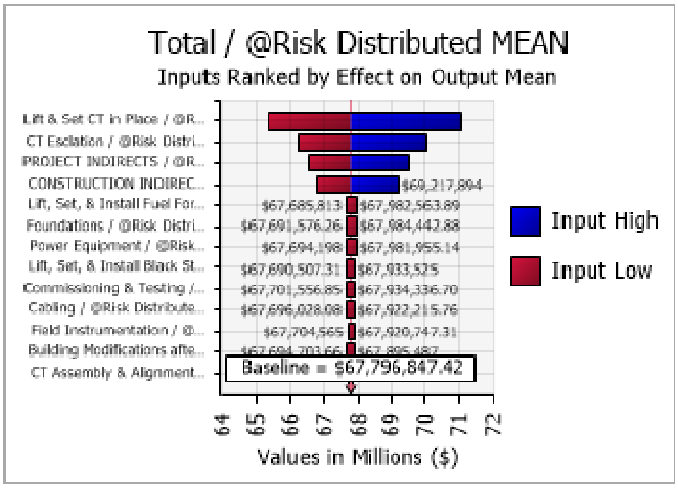
Summary Statistics

Statistic	Value
Minimum	$60,939,206.92
Maximum	$78,334,610.53
Mean	$67,796,847.42
Std. Deviation	$2,389,313.93
Variance	5.709E+012
Skewness	0.2780
Kurtosis	2.7736
Median	$67,661,601.57
Mode	$67,131,722.28
Left X	$64,769,721
Left P	10%
Right X	$71,014,205.14
Right P	90%



Percentiles

Percentile	Value
1%	$62,999,543.25
2.5%	$63,564,846.49
5%	$64,098,247.29
10%	$64,769,721
20%	$65,692,262
25%	$66,061,228.50
50%	$67,661,601.57
75%	$69,407,034.09
80%	$69,842,481
90%	$71,014,205.14
95%	$71,956,305.24
97.5%	$72,748,737.53
99%	$73,637,083.88



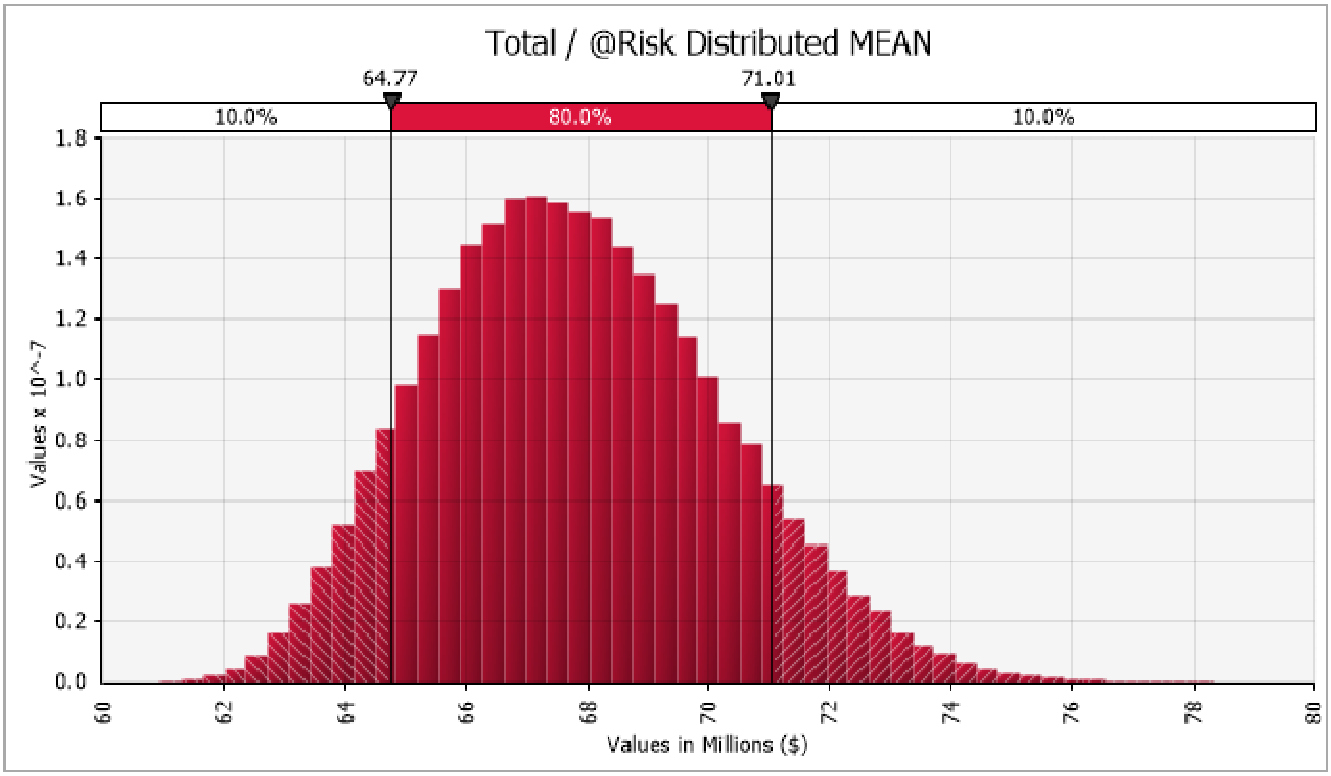
Change in Output

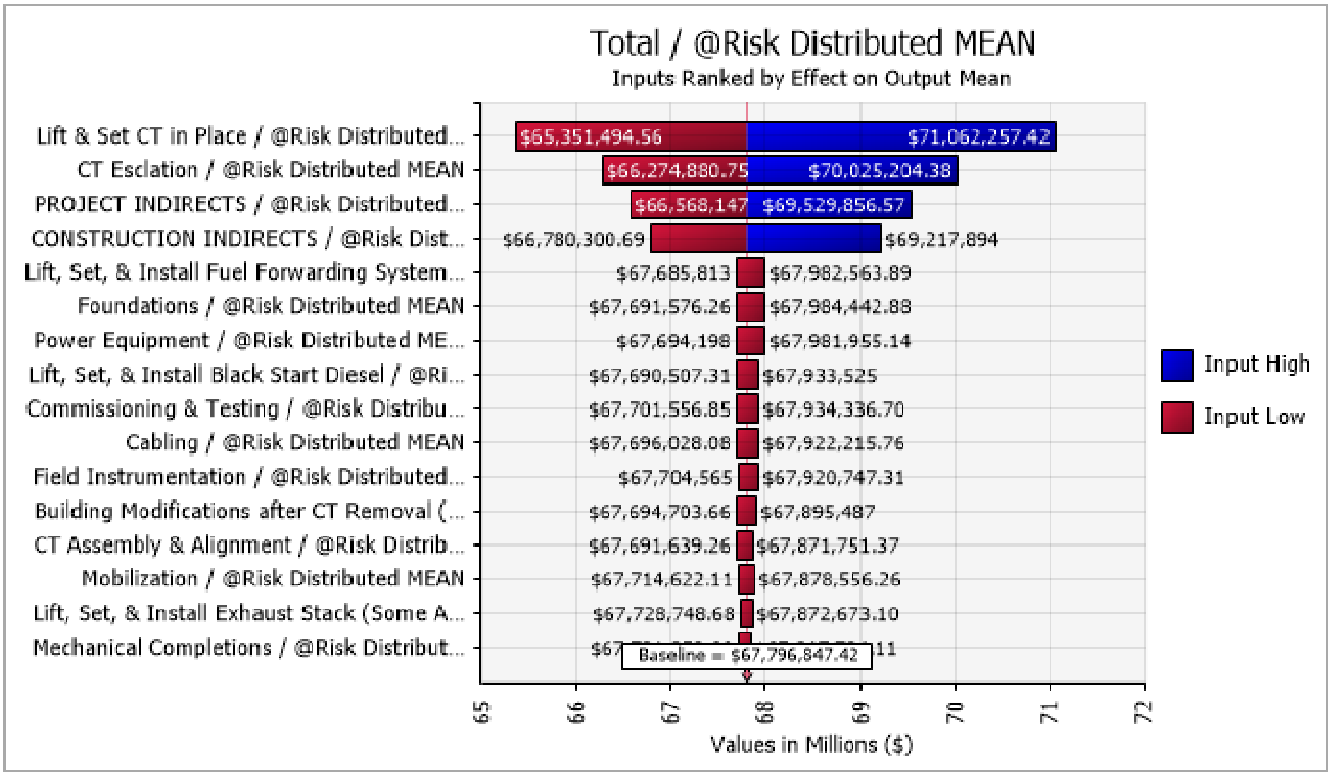
Rank	Name	Lower	Upper
1	Lift & Set CT in Plac...	$65,351,494.56	$71,062,257.42
2	CT Esclation / @Risk...	$66,274,880.75	$70,025,204.38
3	PROJECT INDIRECT...	$66,568,147	$69,529,856.57
4	CONSTRUCTION IN...	$66,780,300.69	$69,217,894
5	Lift, Set, & Install Fu...	$67,685,813	$67,982,563.89
6	Foundations / @Risk...	$67,691,576.26	$67,984,442.88
7	Power Equipment /...	$67,694,198	$67,981,955.14
8	Lift, Set, & Install Bl...	$67,690,507.31	$67,933,525
9	Commissioning & Te...	$67,701,556.85	$67,934,336.70
10	Cabling / @Risk Dist...	$67,696,028.08	$67,922,215.76
11	Field Instrumentatio...	$67,704,565	$67,920,747.31
12	Building Modification...	$67,694,703.66	$67,895,487
13	CT Assembly & Align...	$67,691,639.26	$67,871,751.37

WESLEYVILLE COMBUSTION TURBINE

Total / @Risk Distributed MEAN - '@ Risk Contingency'!J90

Report: Graph Output Report
Performed By: kfiske
Date: Wednesday, August 5, 2026

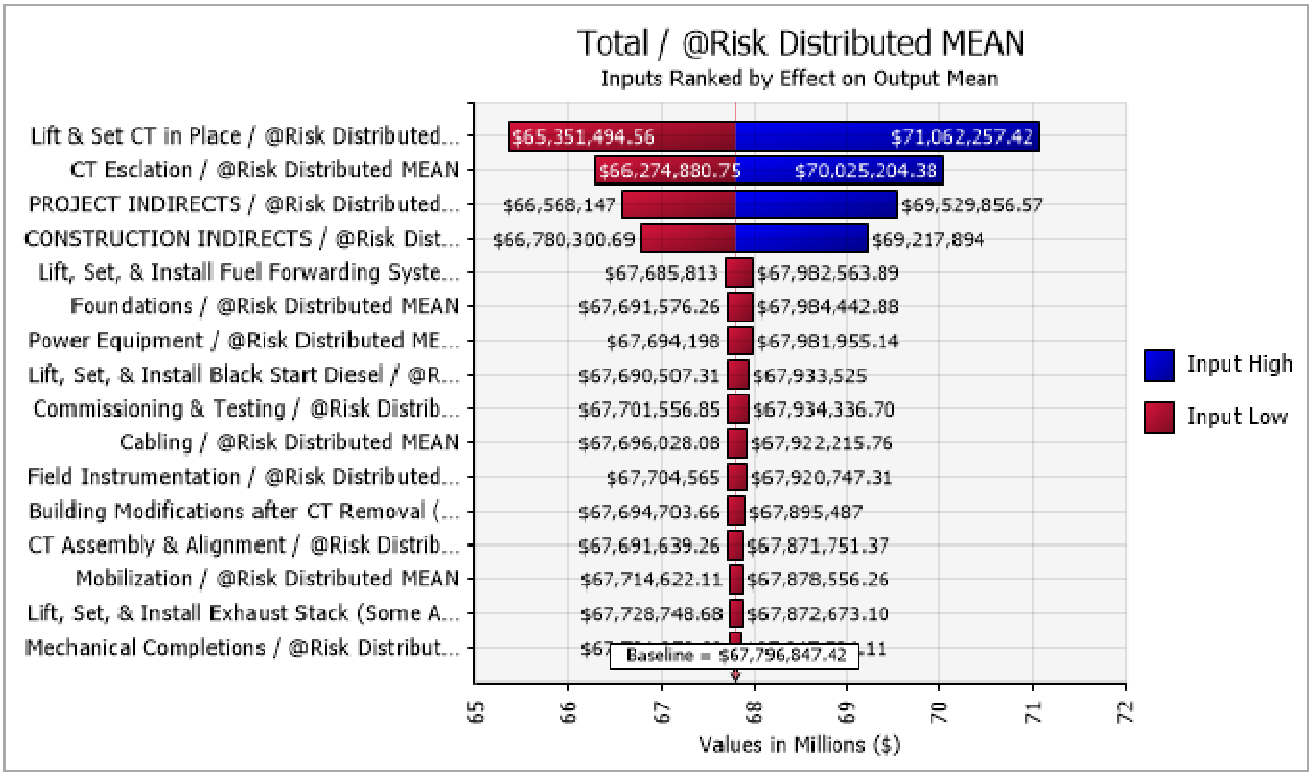




WESLEYVILLE COMBUSTION TURBINE

Total / @Risk Distributed MEAN - '@ Risk Contingency'!J90

Report: Sensitivity Report
Performed By: kfiske
Date: Wednesday, August 5, 2026



Change in Output			
Rank	Name	Lower	Upper
1	Lift & Set CT in Place / @Risk Distributed MEAN	$65,351,494.56	$71,062,257.42
2	CT Esclation / @Risk Distributed MEAN	$66,274,880.75	$70,025,204.38
3	PROJECT INDIRECTS / @Risk Distributed MEAN	$66,568,147	$69,529,856.57
4	CONSTRUCTION INDIRECTS / @Risk Distributed...	$66,780,300.69	$69,217,894
5	Lift, Set, & Install Fuel Forwarding System / @Ri...	$67,685,813	$67,982,563.89
6	Foundations / @Risk Distributed MEAN	$67,691,576.26	$67,984,442.88
7	Power Equipment / @Risk Distributed MEAN	$67,694,198	$67,981,955.14
8	Lift, Set, & Install Black Start Diesel / @Risk Dist...	$67,690,507.31	$67,933,525
9	Commissioning & Testing / @Risk Distributed ME...	$67,701,556.85	$67,934,336.70
10	Cabling / @Risk Distributed MEAN	$67,696,028.08	$67,922,215.76
11	Field Instrumentation / @Risk Distributed MEAN	$67,704,565	$67,920,747.31
12	Building Modifications after CT Removal (WES) /...	$67,694,703.66	$67,895,487
13	CT Assembly & Alignment / @Risk Distributed M...	$67,691,639.26	$67,871,751.37

CONTINGENCY REPORT
September 17, 2026

CLIENT: Newfoundland Power
PROJECT: GREENHILL COMBUSTION TURBINE
Stantec Project Number 1370260073
Report prepared by: Keir Fiske

Project estimate updated September 16, 2026
File Name: "Greenhill CT_Capex_2026-07-09_R8_@RiskRun Sept 17 2026"

@RISK (AACE 40R-08 Probabilistic method)

The @Risk Monte Carlo probabilistic simulation performed 100,000 iterations on the estimate values. The input analysis for this redesign effort was elicited from each of the individual discipline groups for the most representative data on each design focus, these captured values were incorporated for the respective estimate range accuracy and confidence. For the Indirect and Soft cost components, a range of -5% and +30% with 80% confidence was utilized.

The @Risk Monte Carlo Simulation resulted in a P90 Value of $122,073,836.34 and report is attached. The result of this analysis is a determined P90 contingency value of $16,079,055.28 when compared to the estimated value before contingency ($105,994,781.06). The attached output reports provide additional details of the summary below.

@Risk Monte Carlo Simulation Method for determining contingency

@Risk Report P10 Total	$110,531,101.23		P10 Mean_Contingency	$4,536,320.17
		4.28%	@Risk _ Run @ ~10:00 am Sept 17, 2026	
@Risk Report P50 Total	$115,789,881.19		P50 Mean_Contingency	$9,795,100.13
		9.24%	@Risk _ Run @ ~10:00 am Sept 17, 2026	
@Risk Report P90 Total	$122,073,836.34		P90 Mean_Contingency	$16,079,055.28
		15.17%	@Risk _ Run @ ~10:00 am Sept 17, 2026	

AACE 119R-21

Contingency Calculation following the AACE 119R-21 recommended practice was not utilized. With this project being at the FEL3 gate stage and the understood confidence in the values being high, specifically with Quoted CT Equipment, the 119R-21 method does not provide the correct representative values to use for recommending contingency value determination.

AACE 119R-21 Method for determining contingency

	Parameters Used
Estimate Class	
Technology Level	
Complexity Level	

Updated : NOT UPDATED

Table 4 from section 2.6 of AACE 119R-21

High p90	Tech	Complexity L	M	H	Low p10	Tech	Complexity L	M	H	Median p50	Tech	Complexity L	M	H
Class 3	L	3%	11%	20%	Class 3	L	-3%	-9%	-14%	Class 3	L	2%	8%	13%
	M	8%	16%	31%		M	-7%	-12%	-19%		M	6%	11%	19%
	H	13%	23%	37%		H	-10%	-16%	-21%		H	9%	15%	21%
Class 4	L	15%	26%	40%	Class 4	L	-12%	-17%	-22%	Class 4	L	10%	16%	22%
	M	22%	35%	53%		M	-15%	-21%	-26%		M	14%	20%	27%
	H	30%	46%	70%		H	-19%	-24%	-29%		H	18%	25%	32%
Class 5	L	37%	56%	85%	Class 5	L	-21%	-26%	-31%	Class 5	L	21%	28%	36%
	M	48%	73%	114%		M	-25%	-30%	-35%		M	25%	33%	42%
	H	63%	97%	158%		H	-28%	-33%	-38%		H	30%	38%	48%

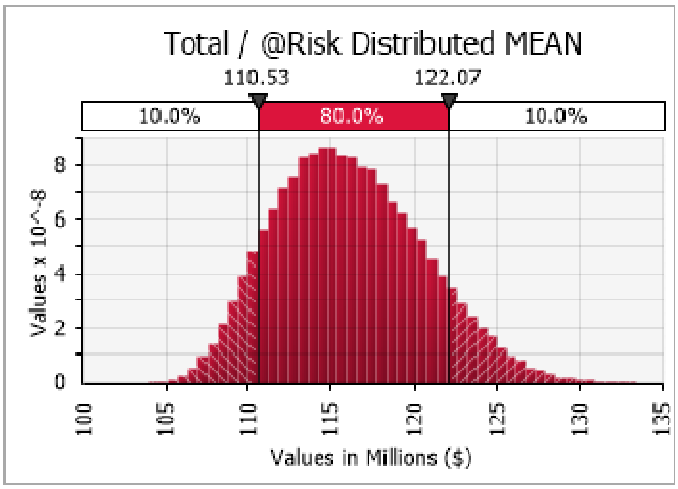
Table 4 – RAND Model-Based Accuracy and Contingency Values

P90 (With x1.2 critical event multiplier) =		*Potential MAX*	$0.00
P50 = (With x1.2 critical event multiplier)		***Most Probable***	**$0.00**
P10 =		*Potential MIN*	$0.00

GREENHILL COMBUSTION TURBINE

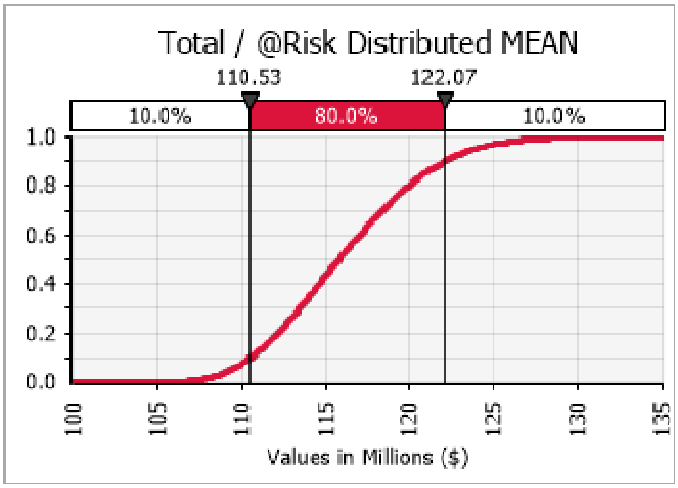
Total / @Risk Distributed MEAN - '@ Risk Contingency'!K92

Report: Compact Output Report
Performed By: kfiske
Date: Thursday, September 17, 2026



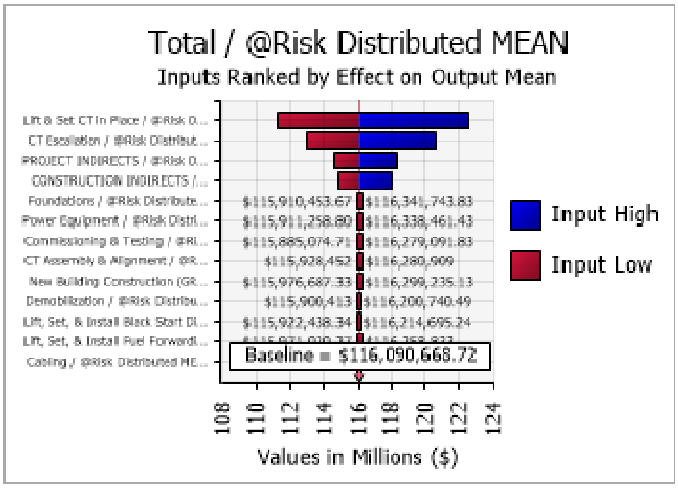
Summary Statistics

Statistic	Value
Minimum	$103,953,326.35
Maximum	$133,393,863.26
Mean	$116,090,668.72
Std. Deviation	$4,413,545.97
Variance	1.948E+013
Skewness	0.3199
Kurtosis	2.7197
Median	$115,789,881.19
Mode	$115,131,075.88
Left X	$110,531,101.23
Left P	10%
Right X	$122,073,836.34
Right P	90%



Percentiles

Percentile	Value
1%	$107,502,267
2.5%	$108,485,996.22
5%	$109,379,698.37
10%	$110,531,101.23
20%	$112,147,620.40
25%	$112,823,150.21
50%	$115,789,881.19
75%	$119,090,635.45
80%	$119,924,461.19
90%	$122,073,836.34
95%	$123,821,396
97.5%	$125,277,854.56
99%	$126,940,185.57



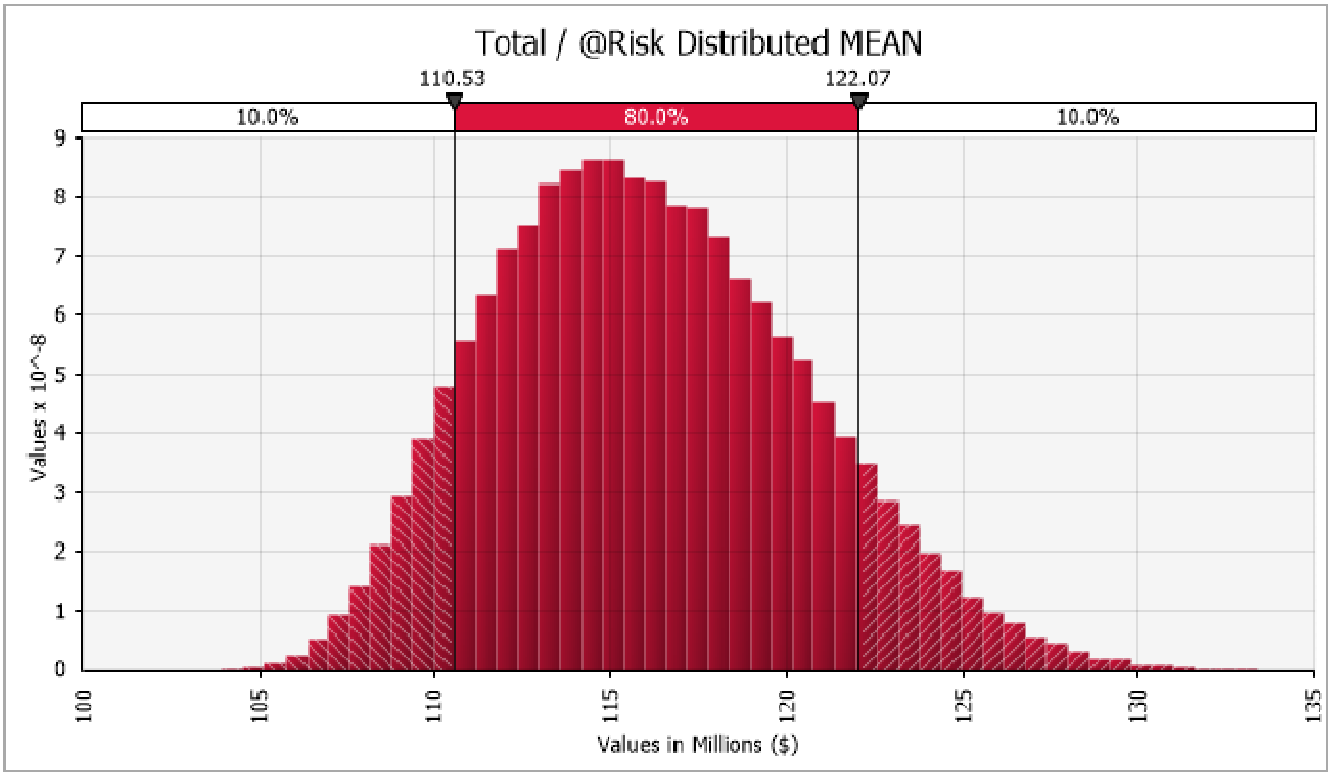
Change in Output

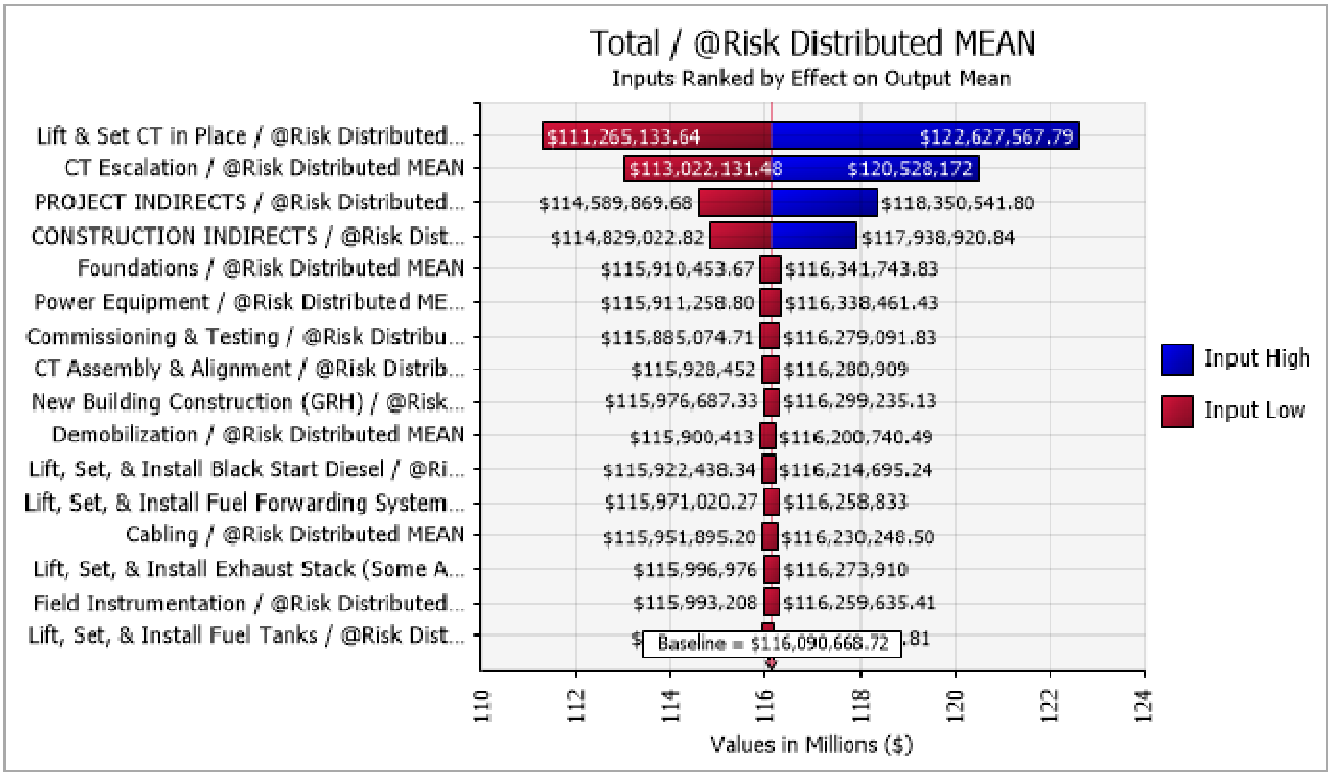
Rank	Name	Lower	Upper
1	Lift & Set CT in Plac...	$111,265,133...	$122,627,567...
2	CT Escalation / @Ri...	$113,022,131...	$120,528,172
3	PROJECT INDIRECT...	$114,589,869...	$118,350,541...
4	CONSTRUCTION IN...	$114,829,022...	$117,938,920...
5	Foundations / @Risk...	$115,910,453...	$116,341,743...
6	Power Equipment /...	$115,911,258...	$116,338,461...
7	Commissioning & Te...	$115,885,074...	$116,279,091...
8	CT Assembly & Align...	$115,928,452	$116,280,909
9	New Building Constr...	$115,976,687...	$116,299,235...
10	Demobilization / @R...	$115,900,413	$116,200,740...
11	Lift, Set, & Install Bl...	$115,922,438...	$116,214,695...
12	Lift, Set, & Install Fu...	$115,971,020...	$116,258,833
13	Cabling / @Risk Dist...	$115,951,895...	$116,230,248...

GREENHILL COMBUSTION TURBINE

Total / @Risk Distributed MEAN - '@ Risk Contingency'!K92

Report: Graph Output Report
Performed By: kfiske
Date: Thursday, September 17, 2026

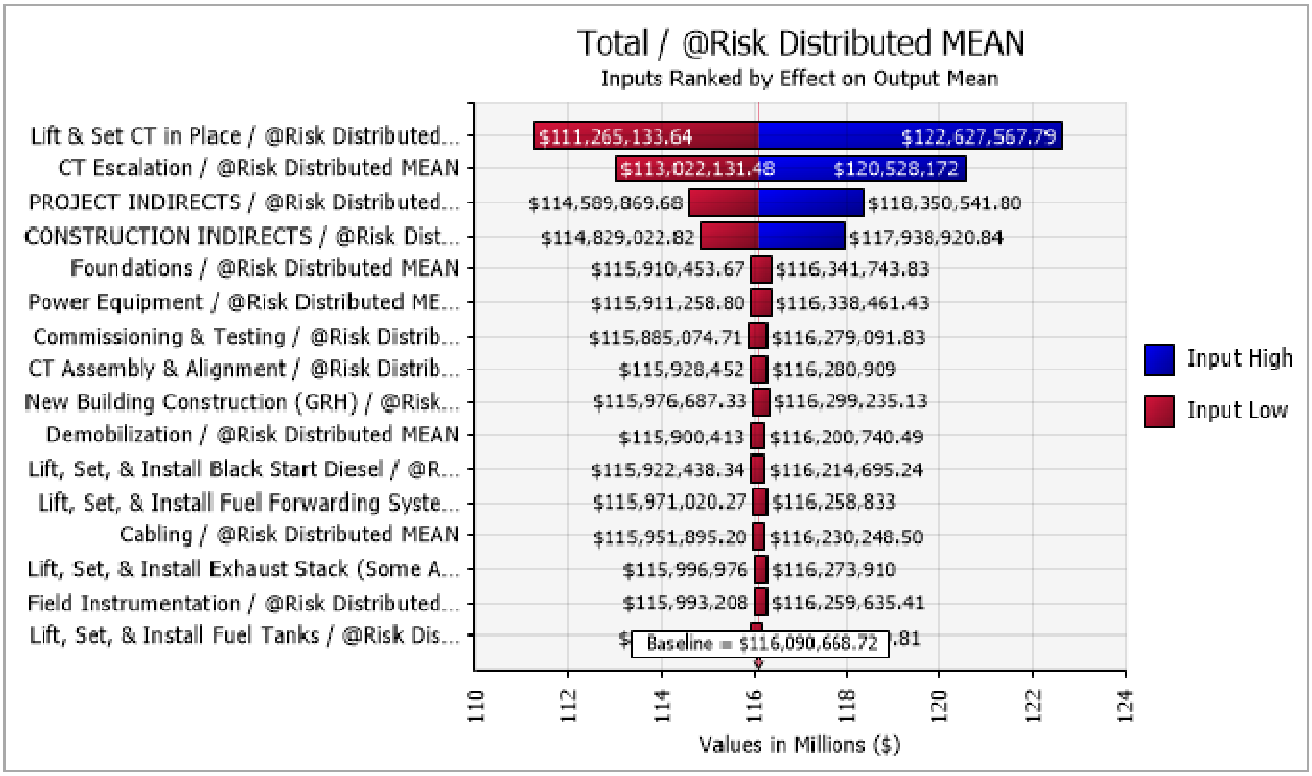




GREENHILL COMBUSTION TURBINE

Total / @Risk Distributed MEAN - '@ Risk Contingency'!K92

Report: Sensitivity Report
Performed By: kfiske
Date: Thursday, September 17, 2026



Change in Output			
Rank	Name	Lower	Upper
1	Lift & Set CT in Place / @Risk Distributed MEAN	$111,265,133.64	$122,627,567.79
2	CT Escalation / @Risk Distributed MEAN	$113,022,131.48	$120,528,172
3	PROJECT INDIRECTS / @Risk Distributed MEAN	$114,589,869.68	$118,350,541.80
4	CONSTRUCTION INDIRECTS / @Risk Distributed...	$114,829,022.82	$117,938,920.84
5	Foundations / @Risk Distributed MEAN	$115,910,453.67	$116,341,743.83
6	Power Equipment / @Risk Distributed MEAN	$115,911,258.80	$116,338,461.43
7	Commissioning & Testing / @Risk Distributed ME...	$115,885,074.71	$116,279,091.83
8	CT Assembly & Alignment / @Risk Distributed M...	$115,928,452	$116,280,909
9	New Building Construction (GRH) / @Risk Distrib...	$115,976,687.33	$116,299,235.13
10	Demobilization / @Risk Distributed MEAN	$115,900,413	$116,200,740.49
11	Lift, Set, & Install Black Start Diesel / @Risk Dist...	$115,922,438.34	$116,214,695.24
12	Lift, Set, & Install Fuel Forwarding System / @Ri...	$115,971,020.27	$116,258,833
13	Cabling / @Risk Distributed MEAN	$115,951,895.20	$116,230,248.50

With every community, we redefine what's possible.

Stantec is a global leader in sustainable engineering, architecture, and environmental consulting. The diverse perspectives of our partners and interested parties drive us to think beyond what's previously been done on critical issues like climate change, digital transformation, and future-proofing our cities and infrastructure. We innovate at the intersection of community, creativity, and client relationships to advance communities everywhere, so that together we can redefine what's possible.

Stantec Consulting Ltd.
845 Prospect Street
Fredericton NB E3B 2T7
stantec.com

APPENDIX F:

Stakeholder Engagement Letters of Support

Town of Centreville-Wareham-Trinity

PO Box 130, Centreville, NL A0G 4P0

July 15, 2026

To whom it may concern:

On behalf of the residents and Council of the Town of Centreville-Wareham-Trinity, I am pleased to express our support for Newfoundland Power's proposed thermal generation replacement project in New-Wes-Valley.

We recently received an overview of the proposed project from Newfoundland Power and understand that the existing generation unit is approaching the end of its service life and must be replaced. The proposed investment will enhance the reliability of backup power throughout our region while also contributing to the overall resilience of the Island's electricity system. These improvements are important to our community, supporting local residents, businesses, and future growth.

Please accept this letter as confirmation of our endorsement of the thermal generation replacement project in New-Wes-Valley. Should you require any additional information, please feel free to contact our office.

Sincerely,

Ivan Pickett
Mayor, Town of Centreville-Wareham-Trinity
355 J.W. Pickersgill Blvd.
Centreville, NL A0G 4P0
townofcwt@bellaliant.com
709-678-2840

HARE BAY
GATEWAY TO THE SEA

July 8, 2026

To whom it may concern:

On behalf of the residents and Council of **Town of Hare Bay**, I am pleased to express our support for Newfoundland Power's proposed thermal generation replacement project in New-Wes-Valley.

Following a recent briefing from Newfoundland Power, we understand that the current generation unit is nearing the end of its operational life and requires replacement. This project represents an important investment in energy infrastructure that will secure the reliability of backup power for communities across our region while enhancing the resilience of the Island's electricity system.

Reliable electrical service is essential to the well-being of our residents, the success of local businesses, and the continued growth and development of our community. We recognize the value of this project in helping to support these priorities.

Please accept this letter as our endorsement of the proposed thermal generation replacement project in New-Wes-Valley. Should further information be required, please contact our office.

Sincerely,

Woodrow Dean Wells
Mayor, Town of Town of Hare Bay

mayor@harebay.ca or townmanager@harebay.ca
Office (709) 537-2187
Cellphone (709) 424-2898

July 9, 2026

Dear Chair and Members of the Public Utilities Board,

On behalf of the residents and Council of the Town of New-Wes-Valley, I am pleased to express our strong support for Newfoundland Power's proposed thermal generation replacement project in New-Wes-Valley.

Council understands that the existing thermal generation unit has reached the end of its service life and requires replacement to ensure the continued reliability of electrical service in our region. We believe this investment is necessary to maintain a dependable supply of electricity for our community and to strengthen the resilience of the Island's electricity system.

Reliable electrical service is essential to the health, safety, and well-being of our residents. Our health care facilities, schools, local businesses, municipal infrastructure, and emergency services all depend on a stable and reliable electricity supply to serve the people of New-Wes-Valley. Interruptions to electrical service can have significant impacts on essential services, economic activity, and the daily lives of our residents.

The importance of a reliable electrical system has increased as many households have transitioned from fossil-fuel heating systems to electric home heating through provincial and federal programs designed to reduce greenhouse gas emissions and lessen reliance on fossil fuels. Today, many homes in our community depend on electricity not only for lighting and appliances but also as their primary source of heat. This makes the reliability of the electrical system particularly important during the winter months, when dependable service is critical to the safety and comfort of residents.

Council recognizes that replacing the aging thermal generation unit is an important investment in maintaining reliable backup generation for our area. This project will help ensure that residents, businesses, and essential public services continue to receive dependable electrical service while supporting the long-term reliability and resilience of Newfoundland and Labrador's electricity system.

Please accept this letter as confirmation of the Town of New-Wes-Valley's support for Newfoundland Power's proposed thermal generation replacement project. We respectfully request that the Public Utilities Board give due consideration to the importance of this investment for the continued reliability of electrical service to our community and the surrounding region.

P.O. Box 64
Badger's Quay, NL A0G 1B0

T: 709.536.2010
F: 709.536.3481

info@townofnewwesvalley.ca
www.townofnewwesvalley.ca

Should you require any additional information, please do not hesitate to contact our office.
Sincerely,

Dean Kean
Mayor, Town of New-Wes-Valley
mayorkean@townofnewwesvalley.ca
709-536-7305

BEOTHIC FISH PROCESSORS LTD.
P.O. BOX 10, VALLEYFIELD, NEW-WES-VALLEY, NL • A0G 1B0
TEL: (709) 536-2425 • FAX: (709) 536-3465

September 14, 2026

Ms. Glenda Power
Director, Stakeholder Relations & Communications
Newfoundland Power
PO Box 8910
St. John's, NL
A1B 3P6

Dear Ms. Power,

Re: PROPOSED GENERATOR UPGRADE – WESLEYVILLE

First of all, I want to thank Newfoundland Power for taking the initiative to visit our production facility in Valleyfield. I think it was a great opportunity for me to discuss with your executives the positive impact that the current generator has had on our operation, and more importantly the future benefits that will come from the upgrade.

Newfoundland Power's proposed replacement of the existing back-up generation unit at Wesleyville is welcomed news. As you know, seafood processing relies heavily on electricity. Downtime due to unplanned outages can result in significant costs as production halts, raw material can spoil, and paid workers are idle. This upgrade will further reduce the impact of unplanned outages and provide needed security and peace-of-mind during the peak of the fishing season.

We are fully supportive of this initiative and once again we cannot thank you enough for your attention and recognition of our need for a reliable energy source.

Sincerely,

Scott Boland

Scott Boland
President, Beothic Fish Processors Ltd.

TOWN OF GARNISH townclerk@eastlink.ca
P. O. Box 70 / Garnish, NL A0E 1T0 / Phone: 709 826-2330 / Fax: 709 826-2173

May 20, 2026

To Whom It May Concern:

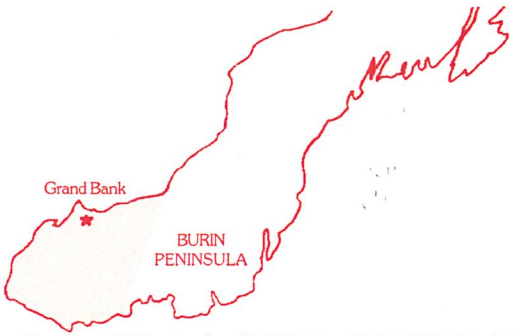
I am writing on behalf of the residents and council of the Town of Garnish to express our strong support for the thermal generation replacement project identified by Newfoundland Power for the area of Greenhill on the Burin Peninsula. We recently were briefed on the proposed project by the utility and understand the current unit is nearing end of life and requires replacement. Modernizing this unit will strengthen backup generation for our region and strengthen the energy grid for the island, which is important to our town, residents and businesses.

Please accept this letter as confirmation of our support for the thermal generation replacement project at Greenhill on the Burin Peninsula. If further information is required, please do not hesitate to contact our office.

Sincerely,

David Yetman

Mayor David Yetman
Town of Garnish
dyetman@townofgarnish.com



Town of Grand Bank
P.O. Box 640, 2 Church Street
Grand Bank, NL
A0E 1W0

☎ (709) 832-1600
Fax: (709) 832-1636
Email: townofgrandbank@townofgrandbank.net
Website: www.townofgrandbank.com

Commercial Center for the Western Side of the Burin Peninsula

A Rich History and Prosperous Future

JOHN BURFITT (JACK)
Mayor

STAN BURT
Deputy Mayor

ROGER BROOKS
Councillor

COLIN CLEMENTS
Councillor

DERRICK DUNNE
Councillor

AMANDA MEADE
Councillor

ELAINE STROWBRIDGE
Councillor

TERRY FLEMING
CAO

MICHELLE PATTEN
Town Clerk

MICHELLE OSMOND
Administrative Clerk

JOE PERIERA
Director of Operations
Facilities Manager

TONY SNOOK
Fire Chief

April 23, 2026

Glenda Power
Director Stakeholder Relations & Communications
55 Kenmount Road
St. John's, NL
A1B 3P6

Dear Ms. Power:

Re: Thermal Generation Replacement Project, Greenhill, Grand Bank, NL

I am writing on behalf of the residents and council of the Town of Grand Bank to express our strong support for the thermal generation replacement project identified by Newfoundland Power in the area of Greenhill, located in the Town of Grand Bank.

The Town of Grand Bank, along with other Town's on the Burin Peninsula, were briefed on the proposed project by the utility and we understand the current unit is nearing end of life and replacement is recommended.

From the briefing, the Town of Grand Bank understands that modernizing this unit will strengthen back-up generation for our region and strengthen the energy grid for the island, which are important to our town, residents and businesses.

Please accept this letter as confirmation of the Town of Grand Bank's support for the thermal generation replacement project at Greenhill on the Burin Peninsula.

If further information is required, please do not hesitate to contact our office.

Sincerely,
Town of Grand Bank

John (Jack) Burfitt
Mayor

Cc: Paul Pike, MHA Burin-Grand Bank

Town of Lawn
P.O. Box 29
Lawn, NL, A0E 2E0
Telephone (709) 873-2439 Facsimile (709) 873-3006
Email: LTC@townoflawn.com

Shane Kearney
Mayor

David Pretty
Deputy Mayor

Paul Slaney
Councillor

Jackie Strang
Councillor

John Strang
Councillor

JeanAnn Lambert
Councillor

Joe Strang
Councillor

Shelby Cox
Clerk/Manager

Natalie Kearney
Assistant Clerk

May 4, 2026

To Whom It May Concern,

I am writing to express the Town of Lawn's strong support for the proposed replacement of the thermal generation project by Newfoundland Power on Greenhill. This will bring significant benefits to the residents of the Burin Peninsula.

We were recently briefed on this project by the utility and understand that the current thermal generation unit is nearing the end of its operational life. This reinforces the importance of moving forward with a modern, reliable, and efficient replacement to ensure continued service for the region.

By modernizing this unit it will strengthen the energy grid for the island and our town but also for local businesses and critical services.

Please accept this letter as confirmation of our support for the project by Newfoundland Power in advancing this initiative and encourage all stakeholders to recognize its long-term value to our communities.

Thank you for your consideration. If further information is required, please do not hesitate to contact our office.

Sincerely,

Shane Kearney
Mayor, Town of Lawn
Shane.kearney@townoflawn.com

Town of Marystown

P.O. Box 1118
Marystown, NL
A0E 2M0
Telephone (709) 279-1661 Fax (709) 279-2862
www.marystown.ca info@townofmarystown.ca

Marystown

May 5, 2026

Council

Mayor
Gerry Brenton

Deputy Mayor
Robert Warr

Councillors
Joan Brown
Georgina Brushett
Andy Edwards
Keith Keating
Gary Myles

Staff

Town Manager
Greg Osmond

Director of Finance and Administration
Melanie Kilfoy

Director of Operations and Public Works
Randy Brockerville

Director of Planning & Economic Development
Ray Nolan

Director of Recreation and Community Services
Debbie Fitzpatrick

To Whom It May Concern,

I am writing on behalf of the residents and Council of the Town of Marystown to express our strong support for the thermal generation replacement project identified by Newfoundland Power for the area of Greenhill on the Burin Peninsula. We were recently briefed on the proposed project by the utility and understand the current unit is nearing end of life and requires replacement. Modernizing this unit will strengthen backup generation for our region and strengthen the energy grid for the island, both of which are important to our town, residents and businesses.

Please accept this letter as confirmation of our support for the thermal generation replacement project at Greenhill on the Burin Peninsula.

If further information is required, please do not hesitate to contact our office.

Sincerely,

Gerry Brenton
Mayor

Town of
Parker's Cove

PO BOX 103,
12 New Branch Road, Parker's Cove, NL A0E 1H0
(709) 443-2216
Council@eastlink.ca

June 2, 2026

To whom it may concern:

I am writing on behalf of the residents and council of the Town of Parker's Cove to express our strong support for the thermal generation replacement project identified by Newfoundland Power for the area of Greenhill on the Burin Peninsula. We recently were briefed on the proposed project by the utility and understand the current unit is nearing end of life and requires replacement. Modernizing this unit will strengthen backup generation for our region and strengthen the energy grid for the island, which is important to our town, residents and businesses.

Please accept this letter as confirmation of our support for the thermal generation replacement project at Greenhill on the Burin Peninsula. If further information is required, please do not hesitate to contact our office.

Sincerely,

Harold Murphy
Mayor
(709)689-9953

Mayor
Harold Murphy

Deputy Mayor
Alex Murphy

Councilor
Sadie Murphy

Councilor
Yvonne Murphy

Councilor
Corey Hickey

Town of St. Lawrence
P.O. Box 128
St. Lawrence, NL A0E 2V0
Telephone (709) 873-2222 Facsimile (709) 873-3352
Email: info@townofstlawrence.com

Kevin Pittman
Mayor

Rodney Doyle Sr.
Deputy Mayor

Ernie Lundrigan
Councillor

Amanda Slaney
Councillor

Colleen Miller
Councillor

Lisa Loder
Councillor

Karl Tarrant
Councillor

Amanda Edwards
Clerk/Manager

May 27, 2026

Public Utilities Board (NL)
P.O. Box 21040
St. John's, Newfoundland and Labrador
Canada, A1A 5B2

To whom it may concern:

I am writing on behalf of the residents and council of St. Lawrence to express our strong support for the thermal generation replacement project identified by Newfoundland Power for the Greenhill area on the Burin Peninsula. We were recently briefed on the proposed project by Derek Mercer, Director of Operations, NL Power and understand the current unit is nearing the end of its life and requires replacement. Modernizing this unit will strengthen backup generation for our region and the island's energy grid, which is important to our town, residents, and businesses in the region.

Please accept this letter as confirmation of our support for the thermal generation replacement project at Greenhill on the Burin Peninsula. If further information is required, please do not hesitate to contact our office.

Sincerely,

Mayor Kevin Pittman
Town of St. Lawrence

REMARKABLE SEAFOOD, RESPONSIBLE CHOICE

To Whom it may Concern:

I am writing on behalf of Clearwater Seafoods Grand Bank, to express our support for

Newfoundland Power's proposed thermal generation replacement project at Grand Bank on the Burin Peninsula.

We have been briefed on the project by Newfoundland Power and understand that the existing unit is nearing the end of its operational life and requires replacement. Reliable electricity service is critical to our operations and the broader business community in the region. Replacing this unit with modern infrastructure will help strengthen backup generation for the Burin Peninsula while also contributing to the overall resilience of the Island's electricity system.

As a local business, we recognize the importance of dependable energy supply to support economic activity, employment, and long-term investment in our region. We believe this project represents an important step in maintaining system reliability and supporting continued growth for businesses and communities alike.

Please accept this letter as confirmation of Clearwater Seafoods Grand Bank support for the thermal generation replacement project. Should you require any additional information. We would be pleased to provide it

Sincerely

Colin Matthews

Chief Engineer

Clearwater Seafoods Grand Bank

709-832-3109