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July 30, 2024

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

Attention: Jo-Anne Galarneau
Executive Director and Board Secretary

Re: Newfoundland and Labrador System Operator Annual Assessments

The Newfoundland and Labrador System Operator ("NLSO") Transmission Planning process involves the execution of power system studies to demonstrate that the power system meets Transmission Planning Criteria necessary for maintaining the reliability of the Newfoundland and Labrador (NL) transmission system. These power system studies are performed by the NLSO and include an annual assessment of the NL transmission system, which is comprised of transmission infrastructure operating at a voltage level of 230 kV or higher and includes the Labrador-Island Link, the Labrador Transmission Assets, the Labrador Interconnected System, and Island Interconnected System. The NLSO also performs, on behalf of Newfoundland and Labrador Hydro ("Hydro"), an assessment of all other transmission system facilities with a rated voltage of 46 kV and above that are under its operational control.

Two reports were generated as a result of these power system studies:

1) TP-R-077: "NLSO Report – 2024 Annual Planning Assessment," Newfoundland and Labrador Hydro, July 26, 2024; and
2) TP-R-078: "NL Hydro Report – 2024 Annual Planning Assessment," Newfoundland and Labrador Hydro, July 26, 2024.

Details of the assessments are provided to the Board of Commissioners of Public Utilities for its information as committed in Hydro's response to PUB-NLH-025 of the *Reliability and Resource Adequacy Study Review* proceeding, filed May 24, 2019.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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NLSO Report - 2024 Annual Planning Assessment

Doc # TP-R-077

Date: 2024/07/26

Executive Summary

A key function of the Newfoundland and Labrador System Operator ("NLSO") is to ensure the coordinated development of a safe, reliable and economical transmission system for transmission customers.

The NLSO Transmission Planning Process involves the execution of power system studies to demonstrate that the power system meets Transmission Planning Criteria. An annual planning assessment of the transmission system is utilized to determine the timing of system additions/modifications to ensure long-term safe, reliable, and economical operation.

This report addresses the Newfoundland and Labrador ("NL") Transmission System, which is comprised of transmission facilities located in NL, operating at a voltage level of 230 kV or higher, including, the Labrador-Island Link ("LIL"), the Labrador Transmission Assets ("LTA"), the Labrador Interconnected System ("LIS") and Island Interconnected System ("IIS").[1,2]

Conclusions of the 2024 Annual Planning Assessment are stated as follows:

- The NL Transmission System includes Radial and Local Networks where outages to system elements may result in customer impacts. Transmission Planning Criteria are not strictly applied in these cases. Rather, these systems are designed to meet customer reliability and cost requirements.
- The steady Transmission Planning Criteria are strictly applied to the Primary Transmission System ("PTS").[3] Steady state analyses were performed and the following conditions were confirmed for the long-term horizon:
    - There are no pre-contingency transmission equipment overloads or voltage violations
    - **There were two transmission equipment overload violations following single contingency events, which include the loss of TL236 and TL266. Further detail is provided in Section 5.3.3.**
- The short circuit analyses were performed and it was confirmed that there are no issues with circuit breaker ratings in the near-term or long-term planning horizons.
- Transient stability analysis is currently in progress as part of ongoing operational studies in support of the Lower Churchill Project ("LCP") integration effort. Due to delays with LIL commissioning, these studies are now expected to be completed by the end of 2024. The final operational study will be provided as part of the 2025 Annual Planning Assessment. The NLSO will also provide a plan for future transient stability analysis, as it is expected it may not be required on an annual basis or will be triggered based on material changes to the IIS or LIS.

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[1] A separate annual planning assessment is performed by Newfoundland and Labrador Hydro ("Hydro"), which includes all system elements 46 kV and above that are under its operational control and not included in the NLSO assessment.

[2] The Churchill Falls (Labrador) Corporation ("CFLCo") 735 kV transmission facilities are currently not included in the NLSO assessment.

[3] All transmission elements with a voltage rating greater than or equal to 230 kV. A power transformer must have a primary and secondary voltage rating of ≥230kV to be considered part of the PTS.

Table of Contents

1 Introduction

The NLSO Transmission Planning Process involves the execution of power system studies to ensure compliance with Transmission Planning Criteria and to determine the timing of system additions and modifications.

The 2024 Annual Planning Assessment covers the period extending to 2033. Cases are assessed to investigate the capability of the transmission system to meet peak load and to meet firm transmission commitments of 250 MW.

This report addresses the NL Transmission System, which is comprised of transmission facilities located in NL, operating at a voltage level of 230 kV or higher, including, the LIL, LTA, the LIS and IIS.[4,5] Analysis is performed to ensure compliance with the NLSO's Transmission Planning Criteria.

The maps of the IIS and LIS are provided in Appendix A.

[4] Hydro performs an annual assessment of the NL interconnected system, which includes all system elements 46 kV and above that are under its operational control and not included in the NLSO assessment.

[5] The CFLCo 735 kV transmission facilities are currently not included in the NLSO assessment.

2 Selection of Study Cases

System models have been developed to reflect the latest load forecast with completed system changes including proposed additions/modifications for future years ranging to 2033. The following system additions are included in the 2033/2034 study cases:

- The Final Under Frequency Load Shedding ("UFLS") Scheme is implemented to allow for increased power transfer over the LIL.[6]
- The Muskrat Falls Generating Station ("MFAGS") is complete, with four 206 MW generating units in service.
- The LIL is operating in Bipole Mode up to its rated capacity of 900 MW (Rdc = 19.29 ohm).
    - All filter banks are available at each of Muskrat Falls and Soldiers Pond Converter Stations.
    - Electrode lines and electrode sites are in service.
- Churchill Falls recall power (less Labrador loads) is available to send to the Island.
- There are two 60 MVAr line reactors installed on the Muskrat Falls end of 315 kV lines L3101 and L3102.
- There are two Soldiers Pond 175 MVAr synchronous condensers in service for analysis (the third unit is available).
- The Maritime Link ("ML") exports are set at 250 MW at Bottom Brook Terminal Station 2 ("BBKTS2") – in both the peak and light load cases.
- Holyrood Thermal Generating Station is out of service with Unit 3 operating in synchronous condenser mode.
- Holyrood combustion turbine (G4) is in-service.
- Proposed Bay d'Espoir Unit 8 (154.4 MW) and new combustion turbine(s) on the Avalon Peninsula are in-service. As per the recommendation of the 2024 Resource Adequacy Plan in order to meet forecasted load growth in the study cases.
- 100 MW of proposed new wind generation is included, as per the recommendation of the 2024 Resource Adequacy Plan, in order to meet forecasted load growth in the study cases.
- Stephenville gas turbine is in-service as a synchronous condenser (no longer available as a generator).
- Hardwoods gas turbine is in-service as a synchronous condenser (no longer available as a generator).
- Wind Hydrogen loads have been connected at the following locations:
    - Stephenville TS 230 kV bus.
    - Voisey's Bay Nickel TS 230 kV bus.
- Wabush Terminal Station upgrades include:
    - Addition of a 23 MVAr capacitor bank C3.
    - Transformers T4 and T5 have been replaced with 125 MVA units.

The following load flow plots for the Year Ten (2033/2034) cases are provided in Appendix B:

- 2033/2034 Peak Load Conditions
- 2033 Light Load Conditions

[6] Hydro and Newfoundland Power are currently in the process of designing the final UFLS scheme.

3 Special Consideration

Special considerations for this study period are discussed in the sections below.

3.1 Operational Studies

Hydro is currently conducting a set of operational studies as part of the integration effort of the LCP assets into the NL Transmission System. The objective of these studies is to identify operating limits or guidelines to allow for the development of instructions to be used by the NLSO. These operational studies include assessments of the transient stability of the IIS and LIS with all LCP assets fully integrated. Transient stability considerations will therefore be outside of the scope of annual planning assessments until the operational studies are complete. The final operational study is expected to be completed by late 2024, with a summary of results provided in the 2025 Annual Planning Assessment.

3.2 Labrador Incremental Load

Hydro is currently undertaking a process to investigate large incremental customer load requests in Labrador. These incremental requests are beyond the baseline forecast and outside of the scope of any annual planning assessment. Transmission system expansion requirements to serve incremental customers in Labrador West will be assessed in a standalone study to be completed in 2024/2025 in accordance with Hydro’s Network Addition Policy.

4 Load Forecast

The 2024 Annual Planning Assessment is based upon the following load forecasts prepared by the Market Analysis and Load Forecasting Section, and the Resource and Transmission Planning Department of Hydro:

- IIS Peak Demand Forecast System – prepared in Fall 2023; and
- LIS Long Term Load Forecast – prepared in Fall 2023.

The IIS and LIS P90[7] forecasted peaks are summarized in Table 1.

Table 1 – Peak Load Forecasts (P90) - IIS and LIS

Forecasted Demand (MW)[8]			
Year[9]	Island Interconnected System	Labrador Interconnected System	
		Lab East	Lab West
2023/24	1,745	79.8	383.4
2024/25	1,784	80.2	383.7
2025/26	1,796	80.9	383.9
2026/27	1,813	81.4	384.2
2027/28	1,831	81.9	384.5
2028/29	1,868	82.5	385.1
2029/30	1,882	83.2	386.5
2030/31	1,903	83.9	387.5
2031/32	1,925	84.7	388.6
2032/33	1,954	85.4	389.7
2033/34	1,984	86.1	391.1

[7] A forecast in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time (i.e., there is a 10% chance of the actual peak demand exceeding the forecast peak demand).

[8] These forecasts do not include Hydro system transmission losses or station service load requirements.

[9] The peak is assumed to occur sometime between December and March of the following year.

5 Steady State Analysis

The NL Transmission System consists of Radial Networks, Local Networks as well as the Primary Transmission System. Radial Network and Local Networks allow for the delivery of electricity to specific customers and Transmission Planning Criteria are not strictly applied. These systems are designed to meet customer reliability and cost requirements. In such a network, the loss of a transmission system element may result in a customer impact. This is in contrast to the Primary Transmission System ("PTS"), where all Transmission System Criteria are strictly enforced.

Steady state analysis is performed on all systems when fully intact (pre-contingency) and following the loss of each single transmission element (single contingency). The pre-contingency analysis is performed to ensure that with all equipment in service under normal operation, power flow through all elements does not exceed their designed rating and voltages are within normal limits (0.95 pu and 1.05 pu). Similarly, the single contingency analysis assesses the system impact following the loss of each individual transmission element, where voltage levels are acceptable within a larger range, or the emergency limits (0.9 pu and 1.1 pu).

The ratings of each type of transmission element are defined as per TP-S-001 - NLSO Facilities Rating Guide. The results of the steady state analysis are described in the sections below.

Load flow plots during normal operation of the NL Transmission System for Year Ten (2033/2034) are provided in Appendix B.

5.1 Radial Networks

5.1.1 Supply to Vale

Vale is supplied by radial transmission line TL208. There are no overloads to this transmission line under normal operation. In the event of an outage to this transmission line, there will be an interruption of electrical supply which is deemed acceptable by Vale.

5.2 Local Networks

5.2.1 The Labrador West System

The transmission system in western Labrador is considered a local network and consists of two 230 kV transmission lines that connect Churchill Falls Terminal Station #1 to the Wabush Terminal Station. These transmission lines are designated as L23 and L24. This network also includes three synchronous condensers at the Wabush Terminal Station (SC1, SC2, and SC3[10]).

[10] SC3 is owned by IOC.

Criteria for this local network were defined as part of Hydro's LIS Transmission Expansion Study that was completed in 2018. Criteria were defined to ensure that there shall be no customer interruption for the loss of a synchronous condenser, a capacitor bank, or a power transformer. Loss of load is permitted for a transmission line outage.

For the purposes of the NLSO annual planning assessment, analysis was performed to assess the impact of a transformer, a synchronous condenser, or a capacitor bank. No violations to the local network criteria were identified.

5.3 Primary Transmission System

Analysis was performed to assess steady state contingencies for the PTS. The PTS includes all transmission elements[11] within the IIS and LIS with a voltage rating greater than or equal to 230 kV. Transmission Planning Criteria are applied to the network to ensure that no system events result in the interruption of load or firm imports or export commitments.

5.3.1 Bay d'Espoir System

The Bay d'Espoir System consists of a network of 230 kV transmission lines that includes the following:

- TL234 between Bay d'Espoir Terminal Station #2 and Upper Salmon Terminal Station
- TL263 between Upper Salmon Terminal Station to Granite Canal Terminal Station
- TL269 between Granite Canal Terminal Station to Bottom Brook Terminal Station #2

This network also includes hydraulic generating facilities at Bay d'Espoir, Upper Salmon and Granite Canal Generation Stations. The Bay d'Espoir Generation Station is the largest plant on the IIS with a total capacity of approximately 613 MW. The largest unit at the Bay d'Espoir Generation Station is Unit 7 (154.4 MW), which can also operate as a synchronous condenser.

Future expansion is assumed for Bay d'Espoir Generation Station with the addition of Unit 8 (154.4 MW), upgrading the total capacity to approximately 767 MW.

This network also includes a 15 MVAr reactor at Granite Canal Tap Terminal Station.

Steady state analysis indicates that within the long term horizon, there are no violations within this network under normal operation or any contingency event involving the loss of any 230 kV line, generator, reactor or synchronous machine.

[11] A power transformer must have a primary and secondary voltage rating of ≥230kV to be considered part of the PTS.

In the event of an outage to the Granite Canal Tap Shunt Reactor, TL269 would be removed from service in accordance with NLSO operating instructions. There are no violations to Transmission Planning Criteria associated with this scenario.

5.3.2 Bay d'Espoir - Western Avalon Corridor

Bay d'Espoir Terminal Station is interconnected to Western Avalon Terminal Station through a network of 230 kV transmission lines that includes the following:

- TL202 between Bay d'Espoir Terminal Station #1 and Sunnyside Terminal Station
- TL206 between Bay d'Espoir Terminal Station #2 and Sunnyside Terminal Station
- TL267 between Bay d'Espoir Terminal Station #2 and Western Avalon Terminal Station
- TL203 between Sunnyside Terminal Station and Western Avalon Terminal Station
- TL207 between Sunnyside Terminal Station and Come by Chance Terminal Station
- TL237 between Come by Chance Terminal Station and Western Avalon Terminal Station

This network also includes four 38.45 MVAr capacitor banks at Come by Chance Terminal Station.

Steady state analysis indicates that within the near- and long-term horizons there are no violations in this corridor under normal operation or any contingency event involving the loss of a transmission line or capacitor bank.

There are transmission constraints on the 230 kV lines[12] to the Avalon Peninsula during a LIL bipole outage (N-2 contingency), but it is outside the scope of the annual planning assessment and is currently being investigated as part of another study.

Operating limits in this corridor are defined in accordance with NLSO guidelines. Transient stability limits for this transmission corridor are currently being assessed as part of the operational studies mentioned in Section 3.1.

5.3.3 Avalon Peninsula System

The Avalon Peninsula is the largest load center on the IIS that is comprised of a network of 230 kV transmission lines that include the following:

- TL201 and TL217 between Western Avalon Terminal Station and Soldiers Pond Terminal Station
- TL265 and TL268 between Soldiers Pond Terminal Station and Holyrood Terminal Station

[12] TL201, TL202, TL203, TL206, TL207, TL217, TL237 and TL267.

- TL242 and TL266 between Soldiers Pond Terminal Station and Hardwoods Terminal Station
- TL236 between Hardwoods Terminal Station and Oxen Pond Terminal Station
- TL218 between Oxen Pond Terminal Station and Holyrood Terminal Station

This network also includes synchronous condensers at Soldiers Pond as well as Unit 3 at Holyrood Generating Station and the Gas Turbines at Holyrood and Hardwoods Terminal Station.

Steady state analysis indicates that within the near- and long-term horizons there are two violations within the Avalon Peninsula System following a contingency event involving the loss of a transmission line. These violations include the following:

Table 2 - Avalon Violations

Contingency	Violation	Year of Violation
Loss of TL236	Overload of TL218	2034
	Overload of HWD-T1	2031
	Overload of HWD-T2	2034
	Overload of HWD-T3	2031
	Overload of HWD-T4	2032
Loss of TL266	HRD-T5	2033
	Overload of TL-242	2031

The violations in Table 2 will be further assessed prior to the 2025 NLSO Annual Planning Assessment and proposed solutions will be provided. The advancement of these violations are due to load growth in the St. John's area and the planned retirement of the Hardwood Gas Turbine as a generator.[13]

There are transmission constraints on the 230 kV lines[14] to the Avalon Peninsula during a LIL bipole outage (N-2 contingency), but they are outside the scope of the annual planning assessment and are currently being investigated as part of another study.

Operating limits on the Avalon Peninsula are defined in accordance with NLSO operating limits.

5.3.4 Western Island Interconnected System

The Western Island Interconnected system consists of a network of 230 kV transmission lines that include the following:

- TL204 between Bay d'Espoir Terminal Station #1 and Stony Brook Terminal Station

[13] The HWD CT will remain as a synchronous condenser only.

[14] TL201, TL202, TL203, TL206, TL207, TL217, TL237 and TL267.

- TL231 between Bay d'Espoir Terminal Station #2 and Stony Brook Terminal Station
- TL205 and TL232 between Stony Brook Terminal Station and Buchans Terminal Station
- TL233 between Buchans Terminal Station and Bottom Brook Terminal Station #2
- TL211 between Bottom Brook Terminal Station #2 and Massey Drive Terminal Station
- TL228 between Buchans Terminal Station and Massey Drive Terminal Station
- TL248 between Massey Drive Terminal Station and Deer Lake Terminal Station
    - Loss of this line isolates Cat Arm generation
- TL247 between Deer Lake Terminal Station and Cat Arm Terminal Station
    - Loss of this line isolates Cat Arm generation

This network also includes three hydro generating facilities, Cat Arm, Hinds Lake and Deer Lake Generation Stations. The two units at the Cat Arm Generating Station can also operate in synchronous condenser mode.

Steady state analysis indicates that within the near- and long-term horizons, there are no violations on this network under normal operation or the loss of any 230kV line or generator. Operating limits for the Western Island Interconnected System are defined in accordance with NLSO operating limits. Transient stability considerations are being investigated as part of operational studies, as addressed in Section 7.

Considerations associated with outages to TL248 are defined in accordance with NLSO operating instructions.

5.3.5 The Exploits System

This network only includes the 230 kV line from Stony Brook Terminal Station to the Grand Falls Terminal Station (TL235). The loss of this line isolates Exploits Generation from the rest of the Island Interconnected System, which results in no violations.

5.3.6 The Labrador 315 kV System

The LIS consists of two 315 kV transmission lines between Churchill Falls Terminal Station #2 and Muskrat Falls Terminal Station #2. These two lines are designated as L3101 and L3102.

Table 3 provides a summary of the pre-contingency transformer loading levels across the planning horizons for transformers located on the LIS that fall under the planning authority of the NLSO.

Table 3 – Transformer Peak Loads

Transformer	2033/2034	
	MVA	%
CHFTS2-T1	74.97	8.9%
CHFTS2-T2	74.75	8.9%

Table 4 provides the transformer loading with the largest transformer out of service.

Table 4 – Transformer Peak Loads – Loss of Largest Transformer[15]

Transformer	2033/2034	
	MVA	%
CHFTS2-T1	137.36	16.4%
CHFTS2 T2	***Out of Service***	

There are no thermal overloads on the 315 kV lines in a pre-contingency state for any generation dispatch scenario on the LIS. With a 315 kV line out of service, the remaining line is limited to avoid under or over frequency if that line trips. The 315 kV transfer limits with a prior line outage are provided in the relevant operating instruction.

5.3.7 The Labrador-Island Link

The LIL is an HVdc bipole that electrically connects the IIS and LIS, which terminates at the Muskrat Falls Converter Station and the Soldiers Pond Converter Station. Steady state analysis indicates that within the near and long-term horizons, there are no violations under normal operation or any contingency event involving the loss of a single pole or an ac filter at the Muskrat Falls or Soldiers Pond terminal stations. The LIL transfer limits are a function of the following:

- Island Demand (MW)
- LIL Mode of Operation (Bipole or Monopole)
- Available frequency response from the ML[16]
- Muskrat Falls Generation Dispatch
- Soldiers Pond Synchronous Condenser Dispatch
- Status of the Labrador 315 kV System
- Accepted[17] amount Under Frequency Load Shedding (UFLS) following a LIL Bipole Trip

[15] The following are two scenarios in which higher flow on the 315 kV system could be experienced:

1. Minimum MFAGS generation and high LIL flow
2. LIL is offline and full MFAGS generation is dispatched

In both cases, the transformers and 315 kV lines would not be overloaded.

[16] Frequency Controller Capacity or Status of ML Runbacks/Power Demand Overrides (“PDOs”).

[17] Once the LIL bipole is proven reliable, the amount of acceptable UFLS will increase as a LIL bipole trip should be less probable.

5.3.8 The Maritime Link

The ML is an HVdc bipole that electrically connects the Island Interconnected System to Nova Scotia via two 170 km subsea cables. The link terminates at BBKTS2 in Newfoundland and at Woodbine Terminal Station in Nova Scotia. Steady state analysis indicates that within the near and long term horizons, there are no violations under normal operation or any contingency event involving the loss of a single pole or an ac filter at BBKTS2. There is currently a firm export commitment of 158 MW[18] to Nova Scotia that must not be interrupted unless there is a LIL pole or bipole outage, at which time the firm exports would be pro-rated based on LIL available capacity. The study cases were all setup with the total firm export commitment on the ML of 250 MW. The ML is capable of operating within its full import (320 MW) and export (500 MW) capacity range with LIL PDOs[19] enabled.

The ML import and export limits are provided in the applicable operating procedure.

[18] At Bottom Brook Terminal Station.

[19] HVdc PDOs are used to help regulate system frequency on the IIS following a HVdc contingency on another link and can be defined as follows:

Runback: a coordinated instantaneous reduction of the power order (imports or exports) on an HVdc link in an attempt to avoid an under or over frequency event.

Run-up: a coordinated instantaneous increase of the power order (imports or exports) on an HVdc link in an attempt to avoid an under or over frequency event.

6 Short Circuit Analysis

Short circuit analysis is required to ensure that the prospective short circuits for equipment locations do not exceed the interrupting capacity of the circuit breakers used to protect the equipment. All circuit breakers with known asset information were assessed.[20] Short circuit analysis was performed and the results indicate that there are no circuit breaker rating violations.

7 Stability Analysis

As discussed in previous sections, Hydro is undertaking operational studies to assess the transient stability of the NL Transmission System. Until these studies are complete, the dynamic analysis of the NL Transmission System shall remain outside of the scope of the annual planning assessment process. Once the LCP assets are closer to being fully integrated into the NL Transmission System, the operational studies can be finalized. The final operational study is currently in progress and is expected to be completed by the end of 2024. The NLSO will provide a plan for future transient stability analysis, as it is expected it may not be required on annual basis or will be triggered based on material changes to the IIS or LIS.

[20] Planned outages are required to gather the unknown asset information, but will eventually be collected during scheduled maintenance to avoid any unnecessary customer impact.

8 Conclusions

The 2024 Annual Planning Assessment focuses on the planning horizon to 2033/2034. Conclusions of the 2024 Annual Planning Assessment are stated as follows:

- The NL Transmission System includes Radial and Local Networks where outages to system elements may result in customer impacts. Transmission Planning Criteria are not strictly applied in these cases. Rather, these systems are designed to meet customer reliability and cost requirements.
- The steady state contingency analysis on the Labrador West Local Network indicates that for all pre-contingency and single contingency conditions, there are no transmission equipment overloads or voltage violations in the near-term or long-term planning horizons provided that approved upgrades will be implemented.
- Transmission Planning Criteria are strictly applied to the Primary Transmission System. Steady state analyses were performed and the following conditions were confirmed for the long-term horizon:
    - There are no pre-contingency transmission equipment overloads or voltage violations.
    - **There were two transmission equipment overload violations following single contingency events, which include the loss of TL236 and TL266. Further detail is provided in Section 5.3.3.**
- The short circuit analyses were performed and it was confirmed that there are no issues with circuit breaker ratings.
- Transient stability analysis is currently in progress as part of ongoing operational studies in support of the LCP integration effort. Due to delays with LIL commissioning, these studies are now expected to be completed by the end of 2024. The final operational study will be provided as part of the 2025 Annual Planning Assessment. The NLSO will also provide a plan for future transient stability analysis, as it is expected it may not be required on an annual basis or will be triggered based on material changes to the IIS or LIS.

9 Reference Documents

1. Operational Study - Stage 4C: Labrador Transfer Analysis (TP-R-034)
2. Labrador Interconnected System - Expansion Study (TP-R-019)
3. TP-S-001 NLSO Standard – Facilities Rating Guide
4. TP-S-003 NLSO Standard – Annual Planning Assessment
5. TP-S-007 NLSO Standard – Transmission Planning Criteria

APPENDIX A

Island and Labrador Interconnected Systems

Figure 1 – Island Interconnected System

Figure 2 – Labrador Interconnected System

APPENDIX B

Load Flow Plots Primary Transmission System Year Ten (2033/2034) – Peak and Light Case

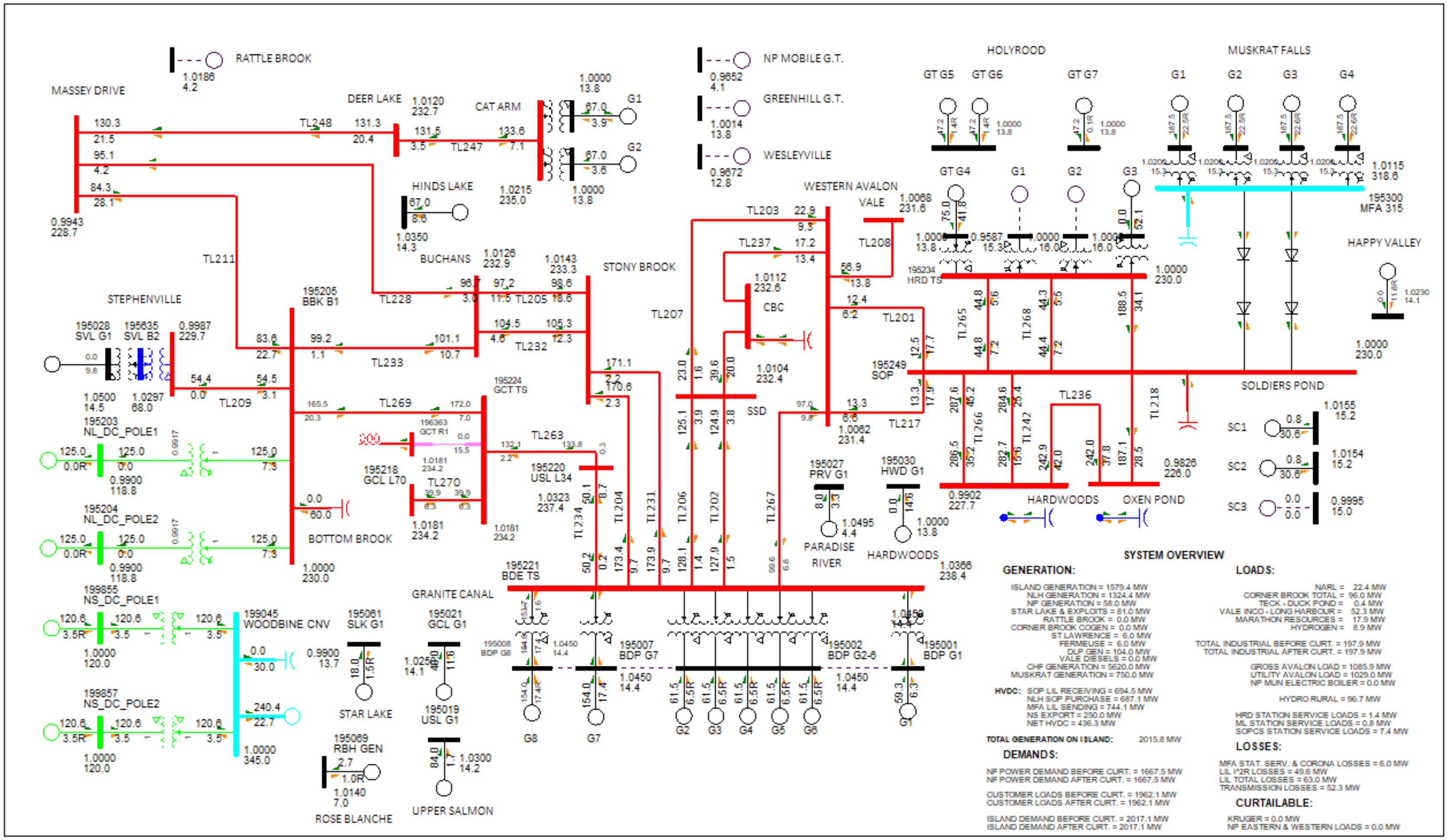

Figure 3 – IIS (2033/34 Peak Conditions – ML Exports (Emera Block – 250 MW))

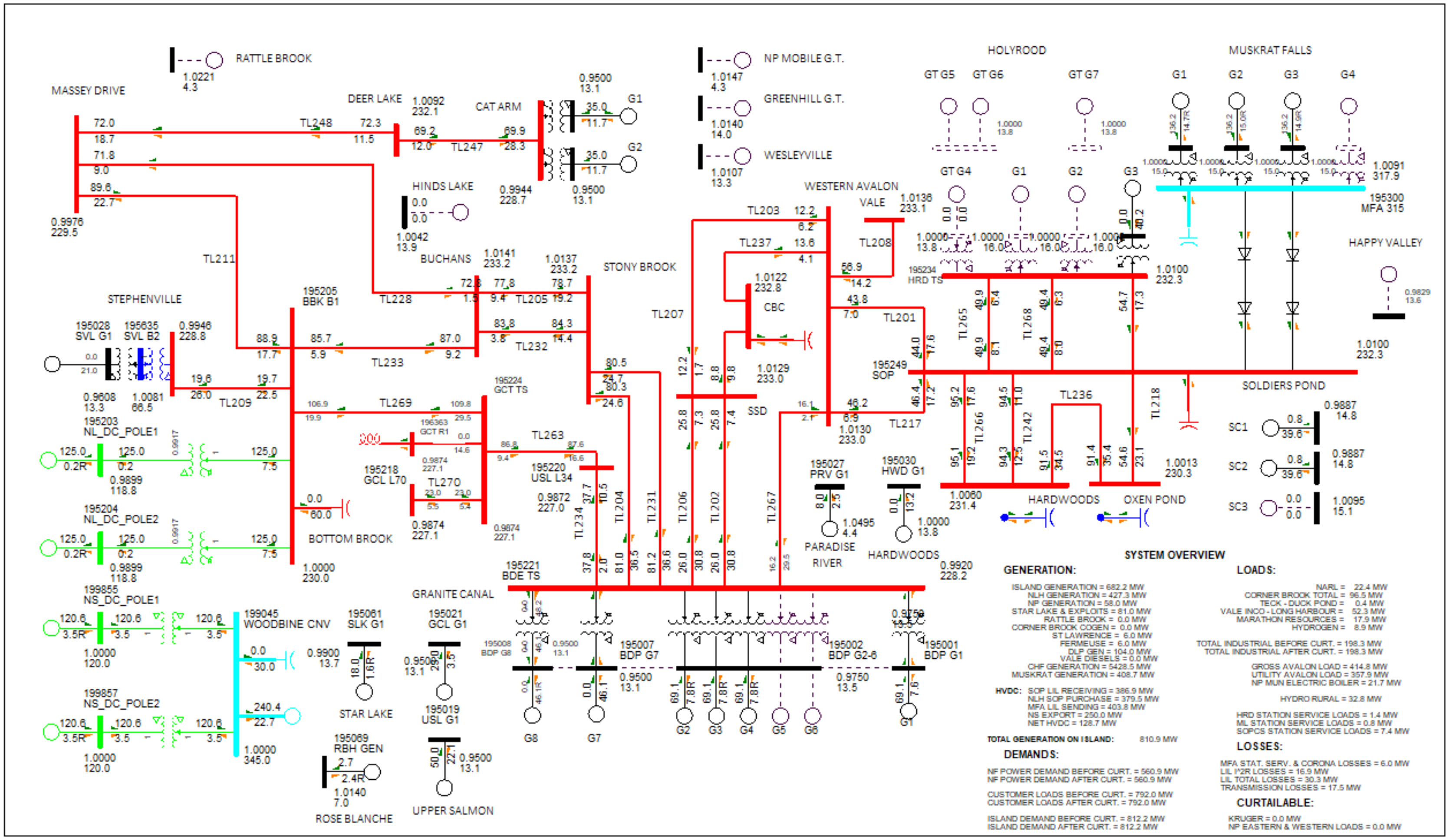

Figure 4 – IIS (2033 Light Conditions – ML Firm Exports (250 MW))

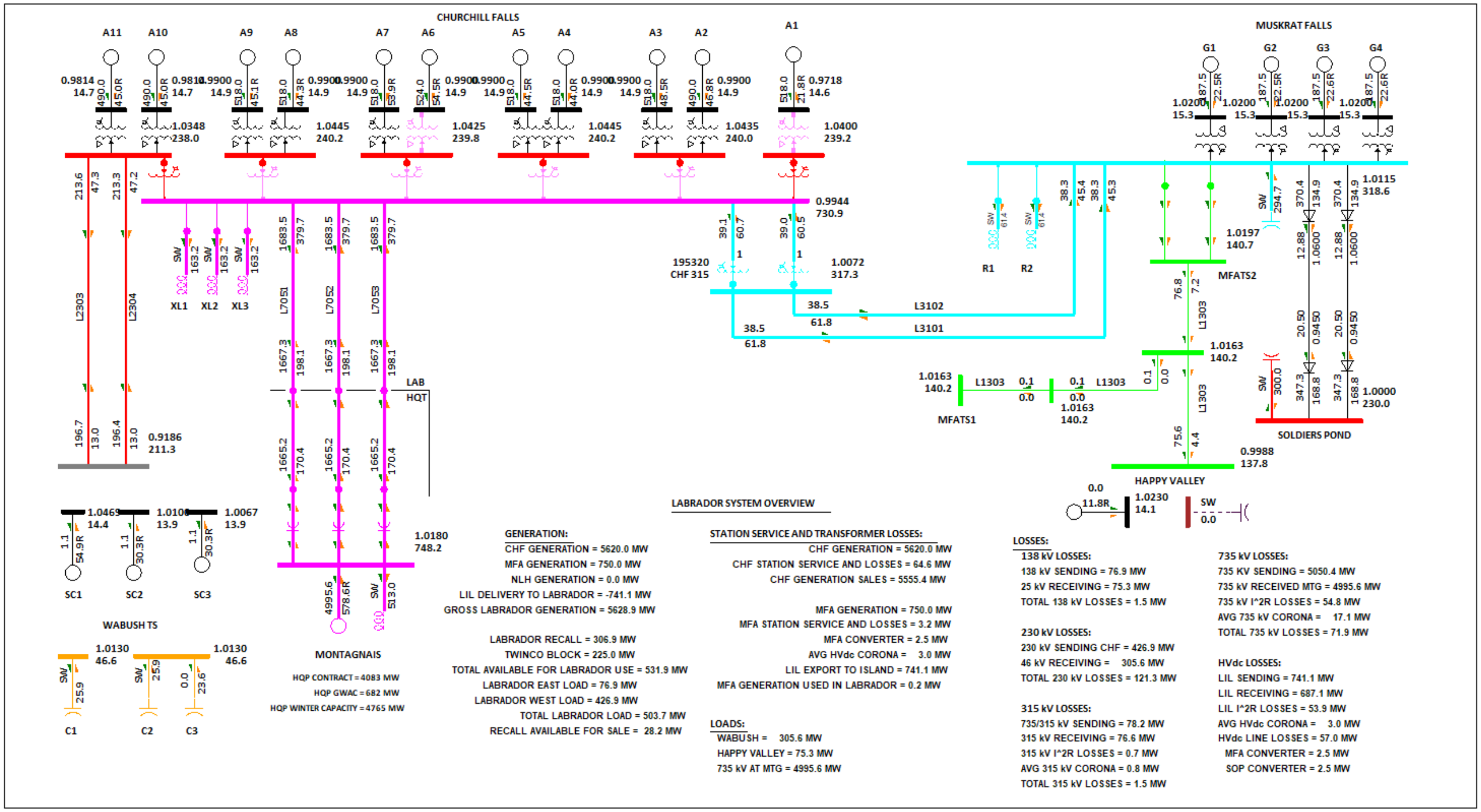

Figure 5 – LIS (2033/34 Peak Conditions)

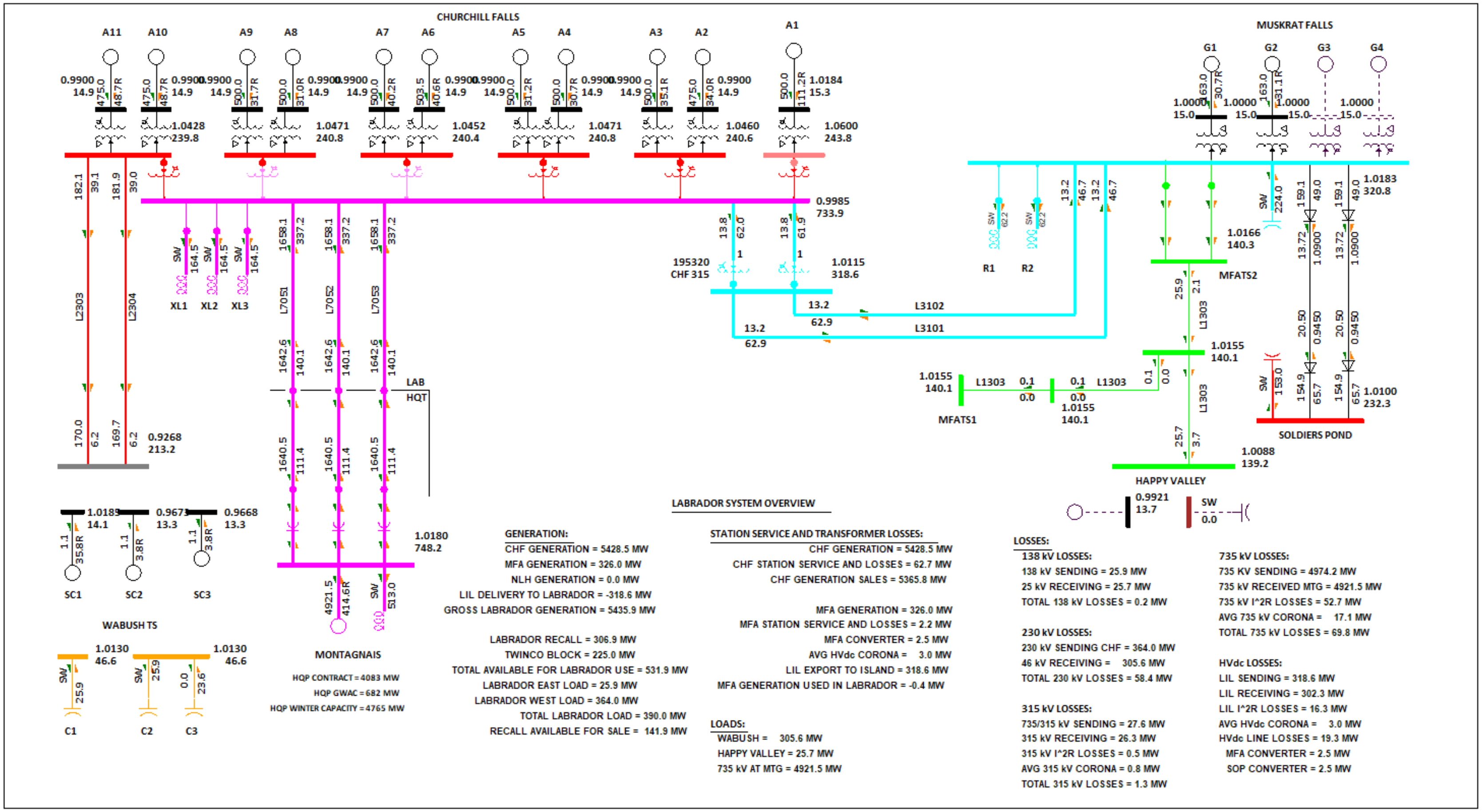

Figure 6 – LIS (2033 Light Conditions)

Document Summary

Document Owner:	Transmission Planning
Document Distribution:	NLSO

Revision History

Revision	Prepared by	Reason for change	Effective Date
0	E. Buglar	Original Issue	2024/06/17

Document Approvers

Position	Signature	Approval Date
Sr. Manager of Transmission and Rural Planning		2024/07/26

Document Control

Regarding NLSO documents: The electronic version of this document is the CONTROLLED version. Please check the NLSO Document Management System SharePoint site for the official copy of this document. This document, when downloaded or printed, becomes UNCONTROLLED.

NL Hydro Report - 2024 Annual Planning Assessment

Doc # TP-R-078

Date: 2024/07/26

Executive Summary

Newfoundland and Labrador Hydro ("Hydro") ensures the coordinated development of a safe, reliable and economical transmission system for the benefit of users within the Province of Newfoundland and Labrador ("NL"). The Hydro transmission planning process involves the execution of power system studies to ensure compliance with Transmission Planning Criteria and to determine the timing of system additions and modifications.

The annual assessment of the NL Transmission System is performed by the Newfoundland and Labrador System Operator ("NLSO") and is summarized in a separate document.[1] The NL Transmission system is comprised of transmission facilities located in NL operating at a voltage level of 230 kV or higher within the Island Interconnected System ("IIS") and Labrador Interconnected System ("LIS") including the Labrador-Island Link ("LIL") and the Labrador Transmission Assets ("LTA"). This document provides an overview of Hydro's assessment, which addresses all other transmission system facilities with a rated voltage of 46 kV and above that are under the operational control of Hydro. The 2024 Annual Planning Assessment revealed:

- Steady state analyses were performed and the following conditions were confirmed for the long-term horizon:
    - There was one pre-contingency transmission equipment overload and no voltage violations:
        - **South Brook Transformer T1 will be slightly overloaded by 2031/2032.**
    - There were two contingency transmission equipment overloads and no voltage violations:
        - **Loss of transmission line L32 (46 kV) to Labrador City results in an overload on line L33 in the year 2031.**
        - **Loss of transmission line L33 (46 kV) to Labrador City results in an overload on line L32 in the year 2029.**
    - Further details on each violation are provided in Section 5.
- The short circuit analysis reveals no issues with circuit breaker ratings in the near-term or long-term planning horizons.
- Transient stability analysis is currently in progress as part of ongoing operational studies in support of the Lower Churchill Project ("LCP") integration effort. Due to delays with LIL commissioning, these studies are now expected to be completed by the end of 2024. The final operational study will be provided as part of the 2025 Annual Planning Assessment. The NLSO will also provide a plan for future transient stability analysis, as it is expected it may not be required on annual basis or will be triggered based on material changes to the IIS or LIS.
- The results of the analysis presented in Newfoundland Power's ("NP") loop assessment (Appendix C), indicates an overload on Sunnyside transformer T1 ("SSD-T1") following the loss of Sunnyside transformer T4 ("SSD-T4"). This is mitigated by dispatching NP gas turbines at Wesleyville ("WES") and Greenhill ("GRH"), however, these gas turbines are approaching their end of life. Therefore, additional transformer capacity or transmission system reinforcements

[1] NLSO Annual Transmission Assessment (2024) – TP-R-077

may be required within the 138 kV STB/SSD Loop System to address this transformer overload. The replacement of the NP gas turbines may also be a viable solution to address the transformer overloads, assuming they can be dispatched in a timely manner. Hydro and NP are currently evaluating the options to address this overload violation.

Table of Contents

1 Introduction

The Hydro Transmission Planning Process involves the execution of power system studies to ensure compliance with Transmission Planning Criteria and to determine the timing of system additions and modifications. The 2024 Annual Planning Assessment covers the period extending to the winter of 2033/34. Cases are assessed to investigate the capability of the transmission system to meet peak load and firm transmission commitments of 250 MW.

This report addresses the NL Interconnected Transmission Systems, which are comprised of transmission facilities located in NL, operating at a voltage level of 46 kV or higher, but less than 230 kV. It is noted that NL Transmission System facilities, operating at a voltage level of 230 kV or higher, are addressed separately as part of the NLSO 2024 Annual Planning Assessment.[2] Analysis is performed to ensure compliance with appropriate criteria, including those defined in TP-S-007 - NLSO Standard – "Transmission Planning Criteria".

The maps of the IIS and LIS are provided in Appendix A.

[2] The NLSO 2024 Annual Planning Assessment addresses the NL Transmission System, which is comprised of transmission facilities located within the IIS and LIS, operating at a voltage level of 230 kV or higher, including, the LIL, and LTA.

2 Selection of Study Cases

System models have been developed to reflect the latest load forecast with completed system changes including proposed additions/modifications for future years ranging to 2033. The following system additions are included in the 2033/2034 study cases:

- The Final Under Frequency Load Shedding ("UFLS") Scheme is implemented to allow for increased power transfer over the LIL.[3]
- The Muskrat Falls Generating Station ("MFAGS") is complete, with four 206 MW generating units in service.
- The LIL is operating in Bipole Mode up to its rated capacity of 900 MW (Rdc = 19.29 ohm).
  - All filter banks are available at each of Muskrat Falls and Soldiers Pond Converter Stations.
  - Electrode lines and electrode sites are in service.
- Churchill Falls recall power (less Labrador loads) is available to send to the Island.
- There are two 60 MVAr line reactors installed on the Muskrat Falls end of 315 kV lines L3101 and L3102.
- There are two Soldiers Pond 175 MVAr synchronous condensers in service for analysis (the third unit is available).
- The Maritime Link ("ML") exports are set at 250 MW at Bottom Brook Terminal Station 2 ("BBKTS2") – in both the peak and light load cases.
- Happy Valley Terminal Station ("HVYTS") is supplied via 138 kV transmission line L1303 connecting the Muskrat Falls Terminal Station 2 ("MFATS2") to the Muskrat Falls Construction Power Station ("MFATS3"), where it taps into existing 138 kV transmission line L1302.
- HVYTS has an additional 138/25 kV 50 MVA transformer, T5.
- The Happy Valley North Side Diesel Plant is assumed to be out of service.
- 138 kV transmission line L1301 from Churchill Falls to Muskrat Falls TS1 is out of service (decommissioning to be complete by 2025).
- Muskrat Falls TS3 has been decommissioned.
- Holyrood Thermal Generating Station is out of service with Unit 3 operating in synchronous condenser mode.
- Holyrood combustion turbine (G4) is in-service.
- Proposed Bay d'Espoir Unit 8 (154.4 MW) and new combustion turbine(s) on the Avalon Peninsula are in-service. As per the recommendation of the 2024 Resource Adequacy Plan in order to meet forecasted load growth in the study cases.
- 100 MW of proposed new wind generation is included, as per the recommendation of the 2024 Resource Adequacy Plan, in order to meet forecasted load growth in the study cases.
- Stephenville gas turbine is in-service as a synchronous condenser (no longer available as a generator).
- Hardwoods gas turbine is in-service as a synchronous condenser (no longer available as a generator).
- A new curtailable electric boiler load has been installed at MUN (both Light and Peak load cases), which is curtailed in Peak load cases.

[3] Hydro and Newfoundland Power are currently in the process of designing the final UFLS scheme.

- Valentine Terminal Station is in service, with the following configuration (both Light and Peak load cases):
  - Phase 2: 6 MVAr capacitor bank on 6.6 kV bus VLN T1, and 4 MVAr capacitor bank on 6.6 kV bus VLN T2.
- Wind Hydrogen loads have been connected at the following locations:
  - Stephenville TS 230 kV bus.
  - Voisey's Bay Nickel TS 230 kV bus.
- Wabush Terminal Station upgrades include:
  - Addition of a 23 MVAr capacitor bank C3.
  - Transformers T4 and T5 have been replaced with 125 MVA units.

The following load flow plots for the Year Ten (2033/2034) cases are provided in Appendix B:

- 2033/2034 Peak Load Conditions.
- 2033 Light Load Conditions.

3 Special Consideration

Special considerations for this study period are discussed in the sections below.

3.1 Operational Studies

Hydro is currently conducting a set of operational studies as part of the integration effort of the LCP assets into the NL Transmission System. The objective of these studies is to identify operating limits or guidelines to allow for the development of instructions to be used by the NLSO. These operational studies include assessments of the transient stability of the IIS and LIS with all LCP assets fully integrated. Transient stability considerations will therefore be outside of the scope of annual planning assessments until the operational studies are complete. The final operational study is expected to be completed by late 2024 following the completion of LIL commissioning, with a summary of results provided in the 2025 Annual Planning Assessment.

3.2 Labrador Incremental Load

Hydro is currently undertaking a process to investigate large incremental customer load requests in Labrador. These incremental requests are beyond the baseline forecast and outside of the scope of any Annual Assessment. Transmission system expansion requirements to serve incremental customers in Labrador will be assessed in a standalone study to be completed in 2024/2025 in accordance with Hydro's Network Addition Policy.

4 Load Forecast

The 2024 Annual Planning Assessment is based upon the following load forecasts prepared by the Market Analysis and Load Forecasting Section, and the Resource and Transmission Planning Department of Hydro:

- IIS Peak Demand Forecast System – prepared in Fall 2023; and
- LIS Long Term Load Forecast – prepared in Fall 2023.

The IIS and LIS P90[4] forecasted peaks are summarized in Table 1.

Table 1– Peak Load Forecasts (P90) - IIS and LIS

Forecasted Demand (MW)[5]			
Year[6]	Island Interconnected System	Labrador Interconnected System	
		Lab East	Lab West
2023/24	1,745	79.8	383.4
2024/25	1,784	80.2	383.7
2025/26	1,796	80.9	383.9
2026/27	1,813	81.4	384.2
2027/28	1,831	81.9	384.5
2028/29	1,868	82.5	385.1
2029/30	1,882	83.2	386.5
2030/31	1,903	83.9	387.5
2031/32	1,925	84.7	388.6
2032/33	1,954	85.4	389.7
2033/34	1,984	86.1	391.1

[4] A forecast in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time (i.e., there is a 10% chance of the actual peak demand exceeding the forecast peak demand).

[5] These forecasts do not include Hydro system transmission losses or station service load requirements.

[6] The peak is assumed to occur sometime between December and March of the following year.

5 Steady State Analysis

The steady state analysis consists of pre-contingency and contingency analysis. The pre-contingency analysis is performed to ensure that with all equipment in service under normal operation, power flows in all elements are at or below normal rating and voltages are within acceptable limits. The contingency analysis performs the same checks, but with each major transmission element removed from service. The ratings are defined as per TP-S-001 - NLSO Facilities Rating Guide. The results of the steady state analysis are described in the sections below.

Load flow plots during normal operation of the NL Transmission System for Year Ten (2033/2034) are provided in Appendix B.

5.1 Summary of Pre-Contingency Transformer Peak Loads

Table 2 provides a summary of the pre-contingency transformer loading levels in Year Ten (2033/2034). A review of the pre-contingency peak cases for long-term horizons indicates that there are no transformer overloads.

Table 2 – Pre Contingency Transformer Load Levels[1]

Station	Unit	Rating (MVA)	2033/34	
			MVA	%
Barachoix	T1	10/13.3/16.7	8.21	49.2%
Bay d'Espoir	T10	15/20/25	11.11	44.4%
	T11	10/13.3/16.7	7.03	42.1%
	T12	15/20/25	11.02	44.1%
Bear Cove	T1	10/13.3/16.7	5.63	33.7%
Berry Hill	T1	15/20/25	2.25	9.0%
Bottom Brook[2]	T1	25/33.3/41.7	31.97	76.7%
	T3	25/33.3/41.7	13.70	32.9%
	T4	40/53.3/66.7	21.80	32.7%
Bottom Waters	T1	10/13.3/16.7	6.05	36.2%
Buchans	T1	40/53.3/66.6	6.74	10.1%
	T2	5/6.6/8.3	3.16	38.1%
Coney Arm	T1	2.5/3.3/4	0.15	3.9%
Conne River	T1	2.5/3.3	2.72	82.4%

Corner Brook Converter	T1	21/28	9.00	32.2%
	T2	21/28	9.36	33.4%
Cow Head	T1	5/6.7/8.3	2.20	26.4%
Daniel's Harbour	T1	1/1.3	0.62	47.7%
	T2	1/1.3	0.61	47.3%
Deer Lake	T1	25/33.3/41.7	9.99	24.0%
	T2	45/60/75	23.58	31.4%
Doyles	T1	25/33.3/41.7	30.74	73.7%
English Harbour West	T1	5/6.7	3.23	48.2%
Farewell Head	T1	10/13.3/16.7	7.37	44.2%
Glenburnie	T1	2.5/3.3	3.12	94.5%
Grand Falls Frequency Converter	T1	30/40/50	22.92	45.8%
	T2	30/40/50	24.02	48.0%
	T3	30/40/50	20.4	40.8%
Grandy Brook	T1	7.5/10/12.5	5.76	46.1%
Hampden	T1	2.5/3.3/4	2.05	51.2%
Happy Valley	T1	30/40/50	28.00	56.0%
	T2	15/20/25//28	15.61	55.8%
	T4	15/20/25//28	15.61	55.8%
	T5	30/40/50	27.36	54.7%
Hardwoods	T1	75/100/125	107.72	86.2%
	T2	40/53.3/66.6	54.96	82.4%
	T3	40/53.3/66.6	59.35	89.0%
	T4	75/100/125	106.86	85.5%
Hawke's Bay[3]	T1	5/6.7	***NOTE 3***	
	T2	2.5/3.3		
Holyrood	T5	15/20/25	23.23	92.9%
	T10	15/20/25	22.62	90.5%
	T6	25/33.3/41.7	10.87	26.1%
	T7	75/100/125	30.77	24.6%
	T8	75/100/125	31.54	25.2%
Howley[4]	T2	7.5/10/12.5	3.76	30.1%
Jackson's Arm	T1	5/6.6/8.3	1.59	19.2%

Main Brook	T1	1.5	0.75	50.0%
Massey Drive	T1	75/100/125	59.76	47.8%
	T2	40/53.3/66.7	37.71	56.5%
	T3	75/100/125	66.84	53.5%
Muskrat Falls TS1	T1	2	0.07	3.7%
Muskrat Falls TS2	T5	75/100/125	43.72	35.0%
	T6	75/100/125	44.91	35.9%
Oxen Pond	T1	150/200/250	176.05	70.4%
	T2	75/100/125	84.90	67.9%
	T3	150/200/250	176.05	70.4%
Parson’s Pond	T1	1/1.3	0.76	58.5%
Peter’s Barren	T1	15/20/25	2.38	9.5%
Plum Point	T1	10/13.3/16.7	3.68	22.0%
Quartzite	T1	15/20/25	19.29	77.2%
	T2	15/20/25	19.16	76.7%
Rocky Harbour	T2	5/6.6/8.3	5.26	63.3%
Roddickton Woodchip	T2	5	2.93	58.7%
South Brook	T1	5/6.6/8.3	8.44	101.7%
Stephenville	T3	40/53.3/66.7	50.32	75.4%
Stony Brook	T1	75/100/125	105.05	84.0%
	T2	75/100/125	103.79	83.0%
St. Anthony Airport[5]	T1	15/20/25	15.62	62.5%
St. Anthony Diesel Plant[5]	T1	15/20/25	11.11	44.5%
Sunnyside	T1	75/100/125	94.55	75.6%
	T4	75/100/125	95.23	76.2%
	T5	15/20/25	10.83	43.3%
Vanier	T1	15/20/25	15.46	61.9%
	T2	15/20/25	15.70	62.8%
Wabush Terminal Station[6]	T1	35/47/65	37.21	57.2%
	T2	35/47/65	38.36	59.0%
	T3	35/47/65	37.76	58.1%
	T4	75/100/125	80.73	64.6%
	T5	75/100/125	80.73	64.6%

	T6	35/47/65	37.15	57.2%
	T7	50/66.6/83.3	53.82	64.6%
	T8	50/66.6/83.3	52.87	63.5%
Wabush Substation (AKA Jean Lake)[7]	T1	20/26.7/33.3	8.68	26.1%
	T2	20/26.7/33.3	18.42	55.3%
Western Avalon	T1	15/20/25	15.89	63.6%
	T2	15/20/25	16.19	64.8%
	T3	25/33.3/41.7	16.37	39.3%
	T4	25/33.3/41.7	16.29	39.1%
	T5	75/100/125	47.73	38.2%
Wiltondale	T1	1.5	0.08	5.2%

Notes:

1. Generator step up transformers and converter transformers are not included as these units have been sized for the full unit capability.
2. It is assumed that a new 230/66 kV, 40/53.3/66.7 MVA power transformer (BBK T4) will be added at Bottom Brook Terminal Station prior to Year 10 (2033).
3. The Hawke's Bay system has a transformer peak of 6.34 MW and is typically supplied by the 15 MVA mobile transformer during the winter season.
4. Rattle Brook hydro generator G1 is not in-service, but is available for capacity support at 4 MW.
5. St. Anthony Diesel Plant is not in-service, but is available for capacity support.
6. WABTS transformers T4 and T5 will both be replaced with 125 MVA units prior to Year 10 (2033).
7. An additional 33.3 MVA transformer (WABSUB T2) will be installed prior to Year 10 (2033).

Violation: It is indicated that South Brook transformer T1 will exceed 100% loading in 2031/32. Transmission Planning will investigate further to confirm the timing of this overload, and will submit a Capital Budget application at the appropriate time if deemed necessary.

5.2 Review of Radial Systems

Radial systems that are impacted by loss of a transmission line are summarized in Table 3.

Table 3 – Radial Transmission Systems and Impact of Line Loss

TL #	kV	From	To	Impact
214	138	Bottom Brook	Doyles	Loss of load in Doyles/Port-aux-Basques area. Newfoundland Power owns mobile gas turbine and mobile diesel located at Grand Bay as well as Rose Blanche hydro site which can supply limited load in area.
215	66	Doyles	Grand Bay	Loss of load in Port-aux-Basques area. Newfoundland Power owns mobile gas turbine and mobile diesel located at Grand Bay as well as Rose Blanche hydro site which can supply limited load in area.
220	69	Bay d'Espoir	Barachoix	Loss of load on the Connaigre Peninsula.

221	66	Peter's Barren	Hawke's Bay	Loss of load in the Hawke's Bay/Port Saunders area. Hydro maintains a 5 MW diesel plant at Hawke's Bay that provides limited back up.
226	66	Deer Lake	Berry Hill	Loss of load in Bonne Bay. TL226 can be isolated in various locations such that Bonne Bay area loads can be supplied from Berry Hill following line switching.
227	66	Berry Hill	Daniel's Harbour	Loss of load from Sally's Cove to Parson's Pond. TL227 can be isolated in various locations such that loads from Sally's Cove to Daniel's Harbour can be supplied from either Berry Hill or Peter's Barren following line switching.
229	66	Wiltondale	Glenburnie	Loss of load on western arm of Bonne Bay to Woody Point.
239	138	Deer Lake	Berry Hill	Loss of load on Great Northern Peninsula north of Bonne Bay. Hydro maintains 5 MW diesel plant at Hawke's Bay and 9.7 MW diesel plant at St. Anthony. With TL239 out switching on the 66 kV will permit up to 25 MVA to be supplied from Deer Lake on the 66 kV TL226 to Berry Hill and then through the Berry Hill 138/66 kV transformer to the 138 kV system via TL259.
241	138	Peter's Barren	Plum Point	Loss of load on Great Northern Peninsula north of Daniel's Harbour. Hydro maintains 9.7 MW diesel plant at St. Anthony that provides limited back up.
244	138	Plum Point	Bear Cove	Loss of load on Great Northern Peninsula Bear Cove and north. Hydro maintains 9.7 MW diesel plant at St. Anthony that provides limited back up.
250	138	Bottom Brook	Grandy Brook	Loss of load in Burgeo.
251	69	Howley	Hampden	Loss of load in White Bay.
252	69	Hampden	Jackson's Arm	Loss of load Jackson's area of White Bay.
254	66	Boyd's Cove	Farewell Head	Loss of load Fogo and Change Islands.
256	138	Bear Cove	St. Anthony Airport	Loss of load St. Anthony – Roddickton area. Hydro maintains 9.7 MW diesel plant at St. Anthony that provides limited back up.
257	69	St. Anthony Airport	Roddickton	Loss of load Main Brook and Roddickton.
259	138	Berry Hill	Peter's Barren	Loss of load on Great Northern Peninsula north of Parson's Pond. Hydro maintains 5 MW diesel plant at Hawke's Bay and 9.7 MW diesel plant at St. Anthony. With TL259 out switching on the 66 kV will permit up to 25 MVA to be supplied from Berry Hill on the 66 kV TL227 to Peter's Barren and then through the Peter's Barren 138/66 kV transformer to the 138 kV system via TL259.
260	138	Seal Cove	Bottom Waters	Loss of load on the Baie Verte Peninsula.
261	69	St. Anthony Airport	St. Anthony Diesel	Loss of load in the St. Anthony area. Hydro maintains 9.7 MW diesel plant at St. Anthony that provides limited back up.
262	66	Peter's Barren	Daniel's Harbour	Loss of load in Daniel's Harbour area. Switching on the 66 kV results in supply of Daniel's harbour via TL227.
264	66	Buchans	Duck Pond	Loss of industrial customer load.
271	69	Star Lake	Valentine	Loss of industrial customer load.
L1303	138	Muskrat Falls	Happy Valley	The system is being reconfigured as part of the Muskrat Falls – Happy Valley Interconnection, but will remain a radial system. Loss of load in the upper Lake Melville area. Hydro maintains a 25 MW gas turbine in Happy Valley that provides limited back up.

5.3 Review of Steady State Contingencies

5.3.1 Line Out Contingencies

A review of the steady state line out contingency analysis concluded that there are two violations to the Transmission Planning Criteria following the loss of the following Hydro owned equipment:

- All transmission lines (46kV to 138kV);
- All Shunt Device (Capacitor Banks and Reactors); and

- All generation units.

These violations include the following:

Table 4 – Line Out Contingencies - Violations		
Contingency	**Violation**	**Year of Violation**
Loss of L32 (46 kV)	Overload of L33 (46 kV)	2031
Loss of L33 (46 kV)	Overload of L32 (46 kV)	2029

Transmission L32 and L33 are both 46 kV lines that supply the Quartzite ("QTZ") and Vanier ("VAN") Terminal Stations in Labrador City. The QTZ and VAN Terminal Stations are also connected forming a 46 kV loop.

The violations in Table 4 will be further assessed prior to the 2025 Annual Assessment and proposed solutions will be provided. The advancement of these violations is due to load growth in the Labrador City area.

5.3.2 Summary of Multi-Transformer Station Contingency Loading

Table 5 provides the transformer loading for each multi-transformer station with the largest transformer out of service.

Table 5 – Multi-Transformer Contingency Load Levels[1]				
Station	**Unit**	**Rating**	**2033/2034**	
		MVA	**MVA**	**%**
Bay d'Espoir	T10	15/20/25	*Out-of-Service*	
	T12	15/20/25	22.71	90.8%
Bottom Brook[2,3,4]	T1	25/33.3/41.7	34.90	89.3%
	T3	25/33.3/41.7	*Out-of-Service*	
Daniel's Harbour	T1	1/1.3	*Out-of-Service*	
	T2	1/1.3	1.23	95.0%
Grand Falls Frequency Converter	T1	30/40/50	*Out-of-Service*	
	T2	30/40/50	30.26	60.5%
	T3	30/40/50	34.74	69.5%
Happy Valley[5]	T1	30/40/50	*Out-of-Service*	
	T2	15/20/25//28	23.16	82.7%

	T4	15/20/25//28	23.16	82.7%
	T5	30/40/50	40.58	81.2%
Hawke's Bay[6]	T1	5/6.7	*Note 6*	
	T2	2.5/3.3		
Holyrood[7]	T5	15/20/25	10.15	40.6%
	T10	15/20/25	*Out-of-Service*	
Massey Drive[2,8]	T1	75/100/125	*Out-of-Service*	
	T2	40/53.3/66.7	55.11	95.3%
	T3	75/100/125	97.68	85.5%
Muskrat Falls TS2[9]	T5	75/100/125	*Out-of-Service*	
	T6	75/100/125	88.53	70.8%
Wabush Terminal Station[10]	T1 (bus B3)	35/47/65	54.54	83.9%
	T2 (bus B3)	35/47/65	56.23	86.5%
	T3 (bus B3)	35/47/65	55.35	85.2%
	T8 (bus B3)	50/66.6/83.3	*Out-of-Service*	
	T4 (bus B4)	75/100/125	*Out-of-Service*	
	T5 (bus B4)	75/100/125	119.06	95.2%
	T6 (bus B4)	35/47/65	54.78	84.3%
	T7 (bus B4)	50/66.6/83.3	79.37	95.3%
Wabush Substation (AKA Jean Lake)[11]	T1	20/26.7/33.3	*Out-of-Service*	
	T2	20/26.7/33.3	27.10	81.4%
Western Avalon[12]	T1	15/20/25	*Out-of-Service*	
	T2	15/20/25	23.81	95.2%

Notes:

1. The loading provided is with the largest transformer in the station removed from service and back up generation online where applicable.
2. There are a few transformers which must be derated due to their active tap position.
3. Bottom Brook 138 kV bus tie switch B2B3 closed.
4. It is assumed that a new 230/66 kV, 40/53.3/66.7 MVA power transformer (BBK T4) will be added at Bottom Brook Terminal Station prior to Year 10 (2033).
5. The Happy Valley GT is not in-service as a generator, but is available for capacity support.
6. The Hawke's Bay system is typically supplied by 15 MVA mobile transformer during the winter season.
7. The 66kV loop between Holyrood and Hardwoods must be opened at 52L to avoid the overload of transformer T5. It is noted that opening the loop leads to Hardwoods transformer T3 being loaded to 95%.
8. MDR 66 kV bus tie B2B4-1 closed.
9. MFATS2 25 kV bus tie B1B2 closed.
10. WABTS transformers T4 and T5 will both be replaced with 125 MVA units prior to Year 10 (2033). Due to the split bus configuration of the WABTS, the transformer capacity is evaluated on a per-bus basis (i.e. bus tie B3B4 remains open).
11. WABSUB 46 kV bus tie B2B3 closed.
12. There is generation available downstream for capacity support.

5.3.3 Summary of Looped System Transformer Contingency Loading

NP executed a 10-year assessment (2024-2033) of looped systems that are supplied by Hydro's power transformers (Appendix C).[7] This loop assessment evaluated a load forecast of P90 + 4.25% to allow for potential demand growth.

As per the results of the analysis presented in NP's loop assessment for the P90 + 4.25% forecast, there is an overload on SSD-T1 following the loss of SSD-T4. This is mitigated by NP gas turbines at WES and GRH, however, these gas turbines are approaching their end of life. Therefore, additional transformer capacity, transmission system reinforcements or gas turbine replacements may be required within the 138 kV STB/SSD Loop System to address this transformer overload.

5.3.4 Generator and Synchronous Condenser Contingency Analysis

There are no violations to the Transmission Planning Criteria following the loss of any single generator or synchronous condenser. The NLSO has developed maximum generator unit guidelines to prevent UFLS for loss of a unit. These limits have become less restrictive with the addition of the LIL and ML frequency controllers.

5.3.5 Shunt Contingency Analysis

There are no violations to the Transmission Planning Criteria following the loss of any other shunt device.

6 Short Circuit Analysis

Short circuit analysis is required to ensure that the prospective short circuits for equipment locations do not exceed the interrupting capacity of the circuit breakers used to protect the equipment. All circuit breakers with known asset information were assessed.[8] Short circuit analysis was performed, and the results indicate that there are no circuit breaker rating violations.

7 Stability Analysis

As discussed in previous sections, Hydro is undertaking operational studies to assess the transient stability of the NL Transmission System. Until these studies are complete, the dynamic analysis of the NL Transmission System shall remain outside of the scope of the annual assessment process. Once the LCP assets are closer to being fully integrated into the NL Transmission System, the operational studies can be finalized. The final operational study is currently in progress and is expected to be completed by the end

[7] NP 138kV/66kV Loop Assessments: 2024-2033.

[8] Planned outages are required to gather the unknown asset information, but will be collected during scheduled maintenance to avoid any unnecessary customer impact.

of 2024. The NLSO will provide a plan for future transient stability analysis, as it is expected it may not be required on annual basis or will be triggered based on material changes to the IIS or LIS.

8 Conclusions

The 2024 Annual Planning Assessment focuses on the long-term planning horizon to 2033/34. Conclusions of the 2024 Annual Planning Assessment are stated as follows:

- Steady state analyses were performed and the following conditions were confirmed for the long-term horizon:
    - There was one pre-contingency transmission equipment overloads and no voltage violations:
        - **South Brook Transformer T1 will be slightly overloaded by 2031/2032.**
    - There were two contingency transmission equipment overloads and no voltage violations:
        - **Loss of transmission line L32 (46 kV) to Labrador City results in an overload on line L33 in the year 2031.**
        - **Loss of transmission line L33 (46 kV) to Labrador City results in an overload on line L32 in the year 2029.**
    - Further details on each violation is provided in Section 5.
- The short circuit analysis reveals no issues with circuit breaker ratings in the near-term or long-term planning horizons.
- Transient stability analysis is currently in progress as part of ongoing operational studies in support of the LCP integration effort. Due to delays with LIL commissioning, these studies are now expected to be completed by the end of 2024. The final operational study will be provided as part of the 2025 Annual Assessment. The NLSO will also provide a plan for future transient stability analysis, as it is expected it may not be required on annual basis or will be triggered based on material changes to the IIS or LIS.
- The results of the analysis presented in NP's loop assessment (Appendix C), indicates an overload on SSD-T1 following the loss of SSD-T4. This is mitigated by dispatching NP gas turbines at WES and GRH; however, these gas turbines are approaching their end of life. Therefore, additional transformer capacity or transmission system reinforcements may be required within the 138 kV STB/SSD Loop System to address this transformer overload. The replacement of the NP gas turbines may also be a viable solution to address the transformer overloads. Hydro and NP are currently evaluating the options to address this overload violation.

9 Reference Documents

1. 2024 NLSO Annual Planning Assessment (TP-R-077)
2. Labrador Interconnected System - Expansion Study (TP-R-019)
3. NLSO Standard – Transmission Facilities Rating Guide (TP-S-001)
4. TP-S-003 NLSO Standard – Annual Planning Assessment
5. TP-S-007 NLSO Standard – Transmission Planning Criteria

APPENDIX A

Island and Labrador Interconnected Systems

Figure 1 – Island Interconnected System

Figure 2 – Labrador Interconnected System

APPENDIX B

Load Flow Plots Primary Transmission System Year Ten (2033/2034) – Peak and Light Case

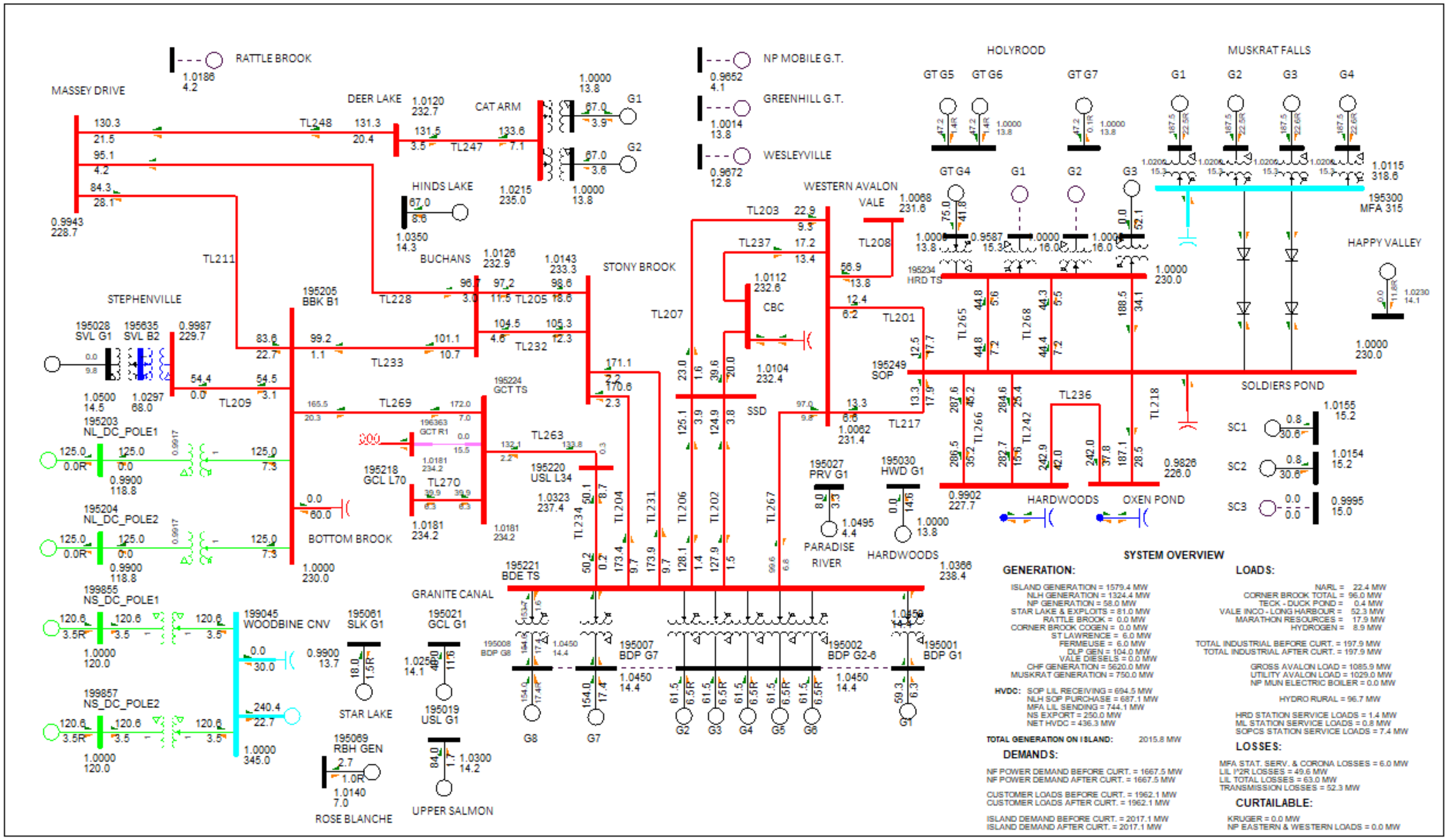

Figure 3 – IIS (2033/34 Peak Conditions – ML Exports (Emera Block – 250 MW))

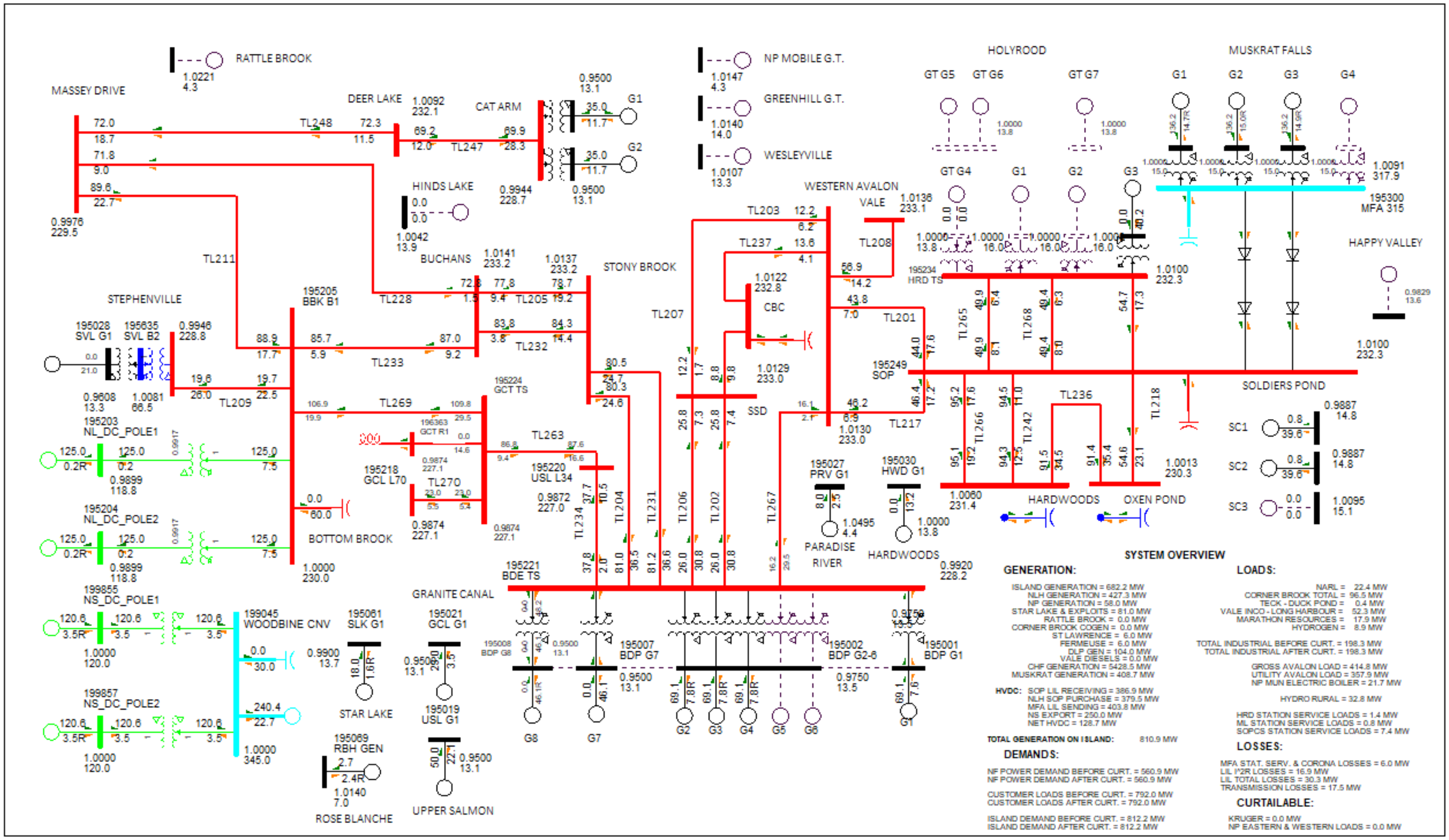

Figure 4 – IIS (2033 Light Conditions – ML Firm Exports (250 MW))

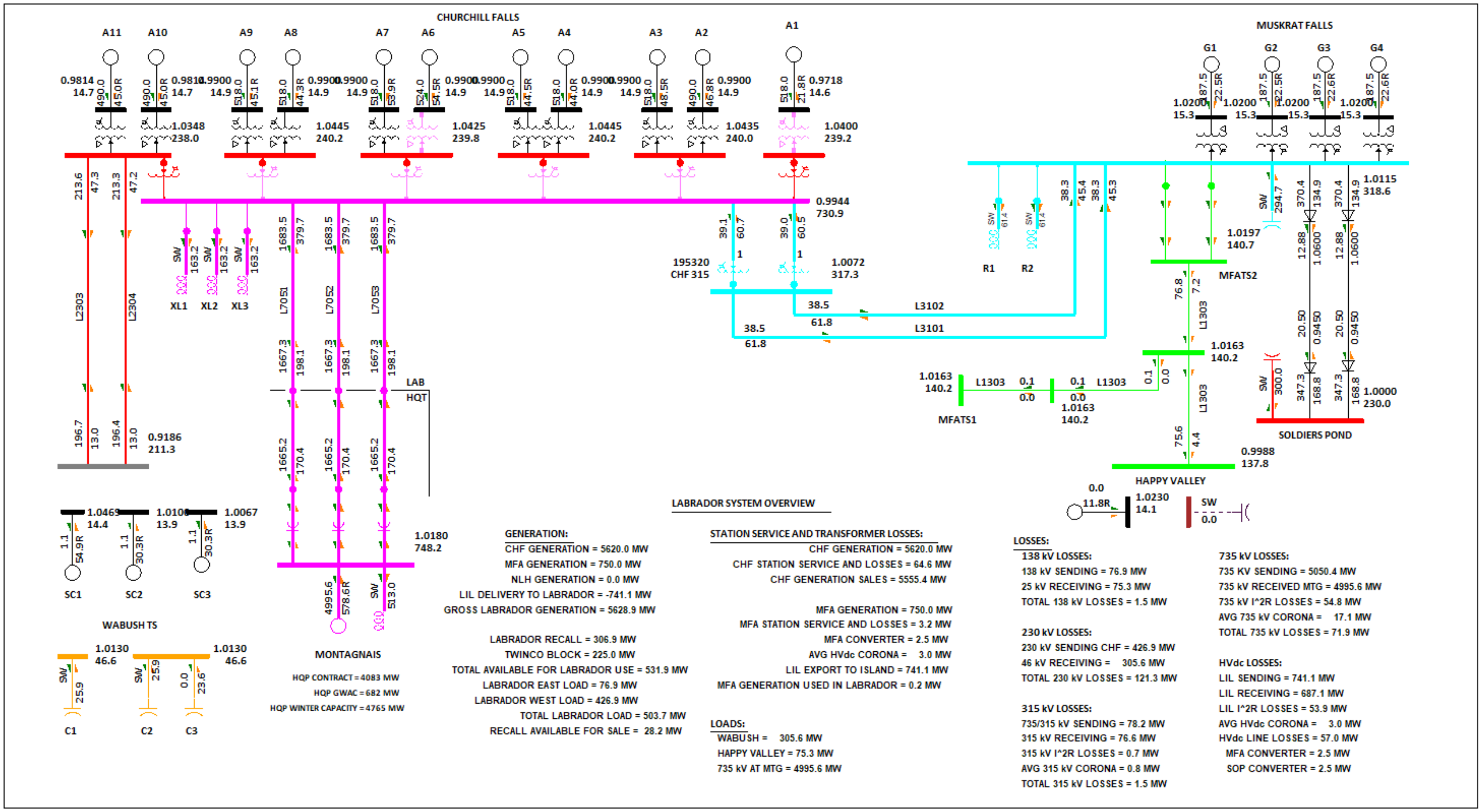

Figure 5 – LIS (2033/34 Peak Conditions)

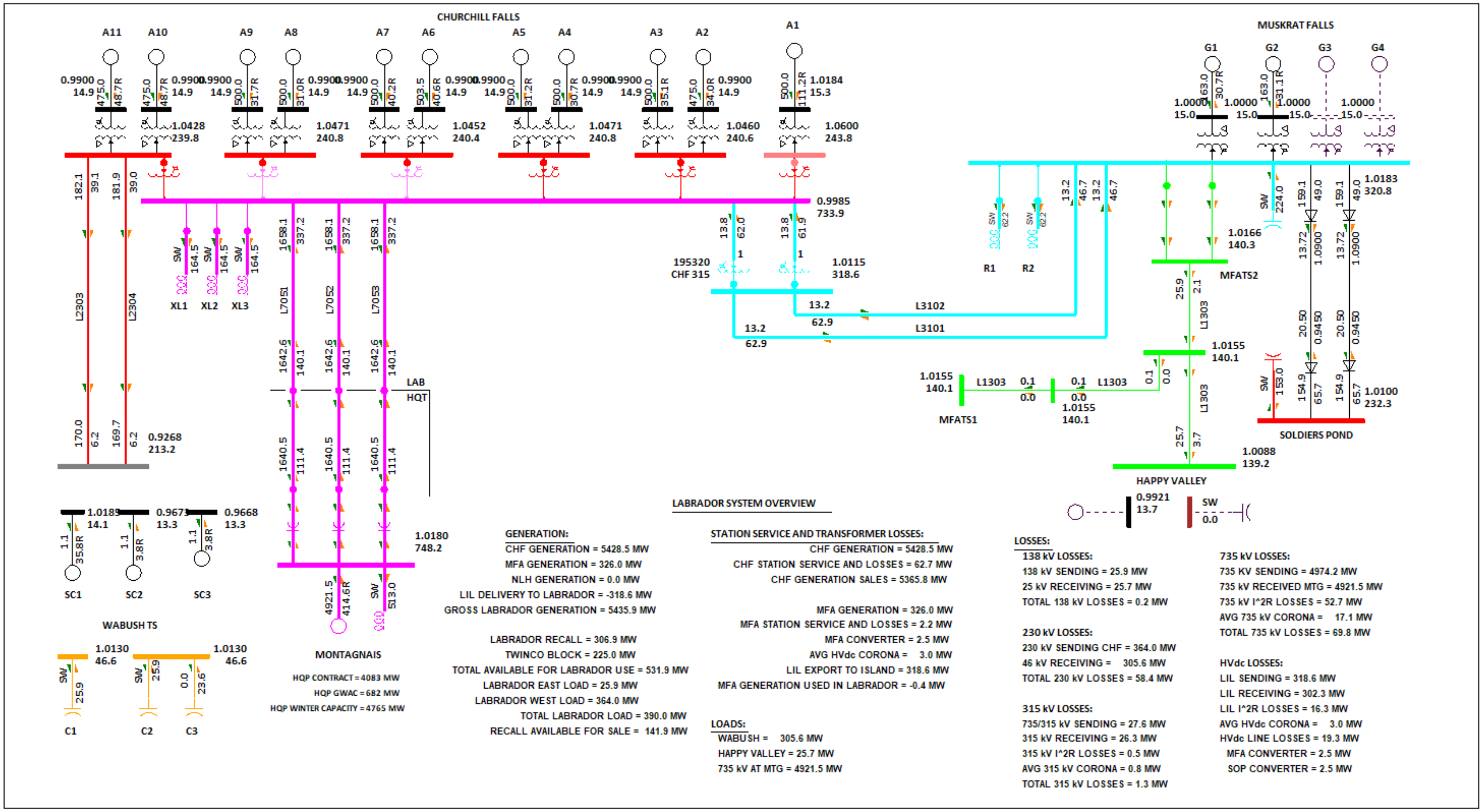

Figure 6 – LIS (2033 Light Conditions)

APPENDIX C

Newfoundland Power’s 138/66kV Loop Assessments 2024-2033

SEE ATTACHMENT A

Document Summary

Document Owner:	Transmission Planning
Document Distribution:	Newfoundland and Labrador Hydro

Revision History

Revision	Prepared by	Reason for change	Effective Date
0	E. Buglar	Original Issue	2024/07/12

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Position	Signature	Approval Date
Sr. Manager of Transmission and Rural Planning		2024/07/26

Document Control

Regarding NLSO documents: The electronic version of this document is the CONTROLLED version. Please check the NLSO Document Management System SharePoint site for the official copy of this document. This document, when downloaded or printed, becomes UNCONTROLLED.

Attachment A

138kV & 66kV Loop Assessments

Rev. 1

2024–2033

138kV & 66kV Loop Assessments

2024-2033

Rev. 1

Prepared by: Tony Jones, P. Eng.

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Revision History

Rev. #	Comments	Date
1	Minor edits.	April 16, 2024
0	Initial version for comments.	March 8, 2024

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1.0 Introduction

The purpose of this report is to assess 138kV and 66kV transmission loop systems based on forecast data for 2024 – 2033. 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 and Newfoundland & Labrador Hydro ("Hydro") power system operators to inform any potential operating procedures that may be required to minimize outages under the contingency scenarios herein.

2.0 Overview of Methodology

CYME was used to model load flows assuming worst-case peaks forecasted for 2023 – 2028 based on the latest P90 In-Feed Forecast provided to Hydro in November 2023. Load data was scaled an additional 5.5% to allow for potential demand growth through to 2033 based on correspondence with Hydro in early 2024.

Potential equipment overloading, as well as any observed voltages outside of either NP's or Hydro's planning criteria limits[1] based on P90 + 5.5% load scenarios for each loop are presented in the following sections. De-ratings of transformer capacities due to tap changer positions were also considered when appropriate.

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. 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. Finally, all load flows within this report assume 160MW of exports over the Maritime Link through Bottom Brook.

3.0 Hardwoods – Oxen Pond 66kV Loop

The Hardwoods – Oxen Pond Loop ("HWD-OPD") is comprised of numerous 66kV transmission lines that run primarily through the St. John's area between the Hardwoods Substation ("HWD") and the Oxen Pond Substation ("OPD"). 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 load flows

[1] 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.

were completed assuming the gas turbine in HWD is unavailable and all CYME modeling was completed with 27MW of Fermeuse Wind disconnected.[2]

3.1 Pre-Contingency

Load flow results for 2033 for the current pre-contingency system configuration are shown in Table 1. [3]

Table 1
HWD-OPD 66kV Loop
System Transformer Loading for 2033

Station	Unit	Max Rating (MVA)	P90 + 5.5%	
			MVA	%
Hardwoods	T1	125	99.3	79.4
	T2	66.6	50.7	76.1
	T3	66.6	54.9	82.4
	T4	125	98.6	78.9
Oxen Pond	T1	250	170.3	68.1
	T2	125	82.2	65.8
	T3	250	170.4	68.2

All voltages in this loop were observed to be within acceptable planning limits and as shown in Table 1, no transformer overloads were observed.

3.2 Single Line Outages (N-1)

Each 66kV transmission line within the HWD-OPD loop were individually disconnected in CYME to observe effects during peak. The results are provided in Table 2.

2 All local generating plants were modeled as "on" for the Hardwoods-Oxen Pond loop, including Cape Broyle, Horsechops, Mobile, Morris, Petty Harbour, Pierre's Brook, Rocky Pond, Seal Cove, Topsail, and Tors Cove.

3 The results in this section include loads associated with the electrification of Memorial University of Newfoundland ("MUN").

Table 2 HWD-OPD 66kV Loop Effect of Single Line Outages	
Transmission Line(s)	**Planning Criteria Violations?**
	P90 + 5.5%
4L / 25L	No
12L / 14L	No
13L	No
15L / 19L	No
16L / 74L	No
18L / 72L / 73L	No
30L / 32L / 67L	Yes
31L / 70L	No
34L / 58L	No
33L / 35L	No
49L / 79L	No
54L	No
69L	No

3.2.1 Loss of 30L

A loss of 30L during the P90 + 5.5% peak resulted in an overload to 14L. Disconnecting 14L results in additional power flow over 31L, 70L and 12L all within winter ampacity limits.

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 2033. 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 P90 + 5.5% case are found in Table 3.

Table 3 HWD-OPD 66kV Loop System Transformer Loading Following XFMR Loss P90 + 5.5% Scenario						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 5.5% (No HWD-T1)**		**P90 + 5.5% (No OPD-T1)**	
			MVA	**%**	**MVA**	**%**
Hardwoods	T1	125	*Out-of-service*		112.5	90.0
	T2	66.6	64.7	97.1	57.4	86.2
	T3	66.6	69.0	104	62.1	93.2
	T4	125	123.9	99.1	111.6	89.3
Oxen Pond	T1	250	188.8	75.5	*Out-of-service*	
	T2	125	91.1	72.9	127.3	102
	T3	250	188.9	75.6	263.9	106

As shown in Table 3, potential transformer overloads were observed with either HWD-T1 or OPD-T1 out-of-service in both the P90 + 5.5%. To mitigate these overloads, the system was re-modeled to consider a 25MW load curtailment associated with MUN's electric boilers, and a voltage management scheme was also implemented for the HWD contingency case. This effectively reduced demand on the overloaded transformers, as shown in Table 4.[4]

Table 4 HWD-OPD 66kV Loop: System Transformer Loading Following XFMR Loss P90 + 5.5% Scenario (MITIGATED via Voltage Management and MUN Curtailment)						
Station	**Unit**	**Max Rating (MVA)**	**P90 Load + 5.5% (No HWD-T1) 25MW MUN Curtail. HWD 66 @ 1.00pu**		**P90 Load + 5.5% (No OPD-T1) 25MW MUN Curtail.**	
			MVA	**%**	**MVA**	**%**
Hardwoods	T1	125	*Out-of-service*		110.7	88.6
	T2	66.6	59.4	89.2	58.8	88.3
	T3	66.6	64.2	96.4	61.1	91.7
	T4	125	115.4	92.3	109.8	87.8
Oxen Pond	T1	250	187.6	75.0	*Out-of-service*	
	T2	125	90.5	72.4	118.8	95.0
	T3	250	187.8	75.1	246.1	98.4

4 A curtailable load agreement associated with the addition of MUN's electric boilers is currently being developed and will be finalized prior to energization of the new load.

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As shown in Table 4, the observed transformer overloads resulting from a loss of HWD-T1 or OPD-T1 may be mitigated by implementing a contingency voltage management scheme at HWD. CYME results show than in either case, transmission voltages may be maintained within emergency limits.

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 the Holyrood Substation ("HRD") and the Western Avalon Substation ("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. It should also be noted that all CYME modeling was completed with the 5MW mobile gas turbine currently installed in Blaketown substation disconnected.[5]

4.1 Pre-Contingency

Load flow results for the 2024-2033 pre-contingency system configuration are shown in Table 5. It was found that no transformer overloads nor system voltage criteria violations were observed in the pre-contingency configuration.

Table 5
HRD-WAV 138kV/66kV Loop
System Transformer Loading for 2033

Station	Unit	Max Rating (MVA)	P90 + 5.5%	
			MVA	%
Blaketown	T3	41.6	27.0	64.9
Bay Roberts	T2	41.6	23.6	56.7
	T3	41.6	22.2	53.4
Western Avalon	T1	25	15.3	61.2
	T2	25	15.5	62.0
	T3	41.7	12.3	29.5
	T4	41.7	12.2	29.3
	T5	125	35.8	28.6
Holyrood	T6	41.7	19.8	47.5
	T7	125	19.7	15.8
	T8	125	57.5	46.0

5 The following NP local generating plants were modeled as "on" for the Holyrood-Western Avalon loop: Victoria, Heart's Content and Pittman's Pond. MG2 in BLK was modeled as "off", as well as New Chelsea, which is the largest NP generator supplying the WAV-HRD loop.

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 6 below.

Table 6 HRD-WAV 138kV/66kV Loop Effect of Single Line Outages	
TL	**Planning Criteria Violations?**
	P90 + 5.5%
39L / 42L / 46L / 47L	No
48L	No
64L	No
56L / 57L / 68L	No
41L	No
80L	No
86L	No

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 2033. 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 P90 + 5.5% peak are found in Tables 8a and 8b.

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Table 8a
HRD-WAV 138kV/66kV Loop
System Transformer Loading Following XFMR Loss (HRD-T8, WAV-T2, WAV-T5)
P90 + 5.5% Scenario

Station	Unit	Max Rating (MVA)	P90 Load + 5.5% (No HRD-T8)		P90 Load + 5.5% (No WAV-T5)		P90 Load + 5.5% (No WAV-T2)	
			MVA	%	MVA	%	MVA	%
Blaketown	T3	41.6	27.0	64.9	25.6	61.5	31.1	74.8
Bay Roberts	T2	41.6	23.3	56.0	23.5	56.5	24.3	58.4
	T3	41.6	22.9	55.0	23.1	55.5	23.9	57.5
Western Avalon	T1	25	15.7	62.8	16.0	64.0	22.7	90.8
	T2	25	16.0	64.0	16.3	65.2	*Out-of-Service*	
	T3	41.7	13.1	31.4	25.2	60.4	12.0	28.8
	T4	41.7	13.1	31.4	25.0	60.0	12.0	28.8
	T5	125	38.2	30.6	*Out-of-service*		35.1	28.1
Holyrood	T6	41.7	43.6	105	20.7	49.6	20.0	48.0
	T7	41.7	43.4	104	20.6	49.4	19.9	47.7
	T8	125	*Out-of-service*		60.0	48.0	58.2	46.6

Table 8b
HRD-WAV 138kV/66kV Loop
System Transformer Loading Following XFMR Loss (BRB-T2, BLK-T3)
P90 + 5.5% Scenario

Station	Unit	Max Rating (MVA)	P90 Load + 5.5% (No BRB-T2)		P90 Load + 5.5% (No BLK-T3)	
			MVA	%	MVA	%
Blaketown	T3	41.6	30.1	72.4	*Out-of-service*	
Bay Roberts	T2	41.6	*Out-of-service*		27.2	65.4
	T3	41.6	42.9	103	26.7	64.2
Western Avalon	T1	25	16.2	64.8	24.5	98.0
	T2	25	16.5	66.0	24.9	99.6
	T3	41.7	11.2	26.9	7.8	18.7
	T4	41.7	11.2	26.9	7.7	18.5
	T5	125	32.7	26.2	22.6	18.1
Holyrood	T6	41.7	19.5	46.8	18.9	45.3
	T7	41.7	19.3	46.3	18.8	45.1
	T8	125	56.5	45.2	55.0	44.0

As shown in Tables 8a and 8b, an overload condition exists for of the N-1 contingency scenarios analyzed during the P90 + 5.5% load scenario. Specifically, with HRD-T8 out of service, HRD-T6 and HRD-T7 are overloaded[6]. This can be mitigated by opening 39L at HRD. Similarly, with BRB-T2 out of service, BRB-T3 is overloaded. This can be mitigated by opening 48L at BRB. Load flow results for the mitigated scenario are presented in Table 9.

Table 9
HRD-WAV 138kV/66kV Loop
MITIGATED Scenarios Following XFMR Loss

Station	Unit	Max Rating (MVA)	P90 + 5.5% (No HRD-T8) 39L Open		P90 + 5.5% No BRB-T2 48L Open	
			MVA	%	MVA	%
Blaketown	T3	41.6	23.3	56.0	31.9	76.7
Bay Roberts	T2	41.6	20.6	49.5	*Out of Service*	
	T3	41.6	20.2	48.6	39.1	94.0
Western Avalon	T1	25	20.6	82.4	16.3	65.2
	T2	25	21.0	84.0	16.6	66.4
	T3	41.7	30.2	72.4	9.7	23.3
	T4	41.7	30.1	72.2	9.7	23.3
	T5	125	88.1	7.05	28.4	22.7
Holyrood	T6	41.7	0	0	22.1	53.0
	T7	41.7	0	0	21.9	52.5
	T8	125	*Out-of-service*		*64.1*	51.3

5.0 Sunnyside – Stony Brook 138kV Loop

The Sunnyside-Stony Brook loop ("SSD-STB") is comprised of a 138kV section that runs through Central Newfoundland between the Sunnyside Substation ("SSD") and the Stony Brook Substation ("STB"). All CYME modeling for this loop was completed with 27MW of St. Laurence Wind disconnected, and 160MW of exports over the Maritime Link.[7] The SSD-STB Loop also supplies the 138kV Burin Peninsula Loop system through the 138kV supply at SSD. As a result, a transmission contingency analysis of the Burin Peninsula System is included in this section.

---

6 HRD-T7 is presently out of service, but is anticipated to return to service for the 2024-2025 winter season.

7 The following local generating plants were modeled as "on" for the Sunnyside-STB loop: Paradise River, Lockston, Port Union, Lawn, West Brook, Rattling Brook, Sandy Brook, Rattle Brook, Hind's Lake, Hawke's Bay and St. Anthony. The gas turbines in Wesleyville and Greenhill were modeled as "off".

5.1 Pre-Contingency

Load flow results for the 2033 pre-contingency configurations are shown in Table 9. The results indicate no transformer overloads or planning criteria violations[8].

Table 9
SSD-STB 138kV Loop
System Transformer Loading for 2033

Station	Unit	Max Rating (MVA)	P90 + 5.5%	
			MVA	%
Sunnyside	T1	125	95.9	76.7
	T4	125	96.4	77.1
Stony Brook	T1	125	71.7	57.4
	T2	125	72.5	58.0

5.2 Single Line Outages (N-1)

The following 138kV transmission lines within the central Newfoundland SSD-STB loop were disconnected in CYME to observe effects during peak: 100L/109L, 124L, 144L, 146L, 130L/132L/133L, 136L/137L/147L. The following 138kV transmission lines within the Burin Peninsula loop were also assessed: TL-212, TL-219, 300L and 308L. The results are provided in Table 10.

8 Presently, a transmission voltage violation exists affecting the 66kV supply to the following substations: Boyd's Cove ("BOY"), Summerside ("SUM"), and Twillingate ("TWG"). Newfoundland Power will be proposing the construction of a new 138kV transmission line from Lewisporte ("LEW") substation to BOY in the coming years to address this issue. As a result, load flow results in this section were derived from models that include this new transmission line.

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Table 10 SSD-STB 138kV Loop Effect of Single Line Outages	
Transmission Line(s)	**Planning Criteria Violations?**
	P90 + 5.5%
100L / 109L	No
121L	No
124L	Yes
146L	No
144L	No
130L / 132L / 133L	No
136L / 137L / 147L	No
TL-212 (Burin System)	Yes
TL-219 (Burin System)	Yes
300L (Burin System)	No
308L (Burin System)	No

5.2.1 Loss of 124L

Transmission line 124L comprises the 138kV loop section between Clarenville Substation ("CLV") and Glovertown Substation ("GLV"). CYME analysis shows that disconnecting 124L at GLV during the P90 + 5.5% load scenario results in undervoltage conditions as low as 0.82pu along the 138kV network near Cobb's Pond ("COB"), Gander ("GAN") and Gambo ("GAM") substations.

To mitigate this effect, a 25MW combustion gas turbine unit was modeled at Wesleyville ("WES")[9], resulting in acceptable post-contingency transmission voltages of 0.956pu at the lowest levels along COB-GAN-GAM. No transformer overloads were observed during the contingency scenario.

5.2.1 Loss of TL-212 or TL-219

Transmission line TL-212 runs between SSD, Monkstown ("MKS"), Bay L'Argent ("BLA") and Linton Lake ("LLK") substations on the Burin Peninsula, while TL-219 runs between SSD and Salt Pond ("SPO") substations. CYME analysis shows that disconnecting TL-219 during the P90 + 5.5% scenario results in an undervoltage condition as low as 0.82pu at SPO. Similarly, by disconnecting TL-212 between MKS and BLA, an undervoltage condition as low as 0.87pu at SPO was observed.

9 NP currently operates an 8MW combustion gas turbine at WES, which is approaching end-of-life.

To mitigate these effects, a 25MW combustion gas turbine unit was modeled at Greenhill ("GRH")[10], resulting in acceptable post-contingency SPO transmission voltages of 0.944pu following the TL-219 outage, and 0.971pu following the TL-212 outage. 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 2033. 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-T1; loading results for the simulated outages for the P90 + 5.5% case are found in Table 11.

Table 11
SSD-STB 138kV Loop
System Transformer Loading Following XFMR Loss for 2033
P90 + 5.5% Scenario

Station	Unit	Max Rating (MVA)	P90 + 5.5% (No SSD-T4)		P90 + 5.5% (No STB-T2)	
			MVA	%	MVA	%
Sunnyside	T1	125	146.0	116.8	78.5	62.8
	T4	125	*Out of Service*		78.9	63.1
Stony Brook	T1	125	78.4	62.7	144.8	115.8
	T2	125	79.2	63.3	*Out of Service*	

To mitigate the transformer overloads presented in Table 11, dispatching 25MW combustion gas turbines at WES and GRH was considered. This successfully mitigated the STB overload condition without any additional loop breaking procedures. In the case of the SSD overload, dispatching 25MW at WES and GRH, in conjunction with opening transmission line 146L between GAN and COB, was able to successfully mitigate the overload condition. See Table 12.

10 NP currently operates a 20MW combustion gas turbine at GRH which is approaching end-of-life.

Table 12 SSD-STB 138kV Loop System Transformer Loading Following Loss of SSD-T4 for 2033 P90 + 5.5% Scenario (MITIGATION)						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 5.5% (No SSD-T4) 25MW in WES 25MW in GRH 146L Open**		**P90 + 5.5% (No STB-T2) 25MW in WES 25MW in GRH**	
			MVA	**%**	**MVA**	**%**
Sunnyside	T1	125	124.7	99.8	79.7	63.8
	T4	125	*Out of Service*		80.1	64.1
Stony Brook	T1	125	76.8	61.4	119.5	95.6
	T2	125	77.6	62.1	*Out of Service*	

6.0 Stephenville – Bottom Brook 66kV Loop

The Stephenville – Bottom Brook Loop ("SVL-BBK") is comprised of a 66kV section that runs through Western Newfoundland between the Stephenville Substation ("SVL") and the Bottom Brook Substation ("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 following load flows assume the retirement of the 50MW Stephenville gas turbine and the subsequent installation of a spare 40/53.3/66.7 MVA transformer in Bottom Brook as per the Hydro 2021 Capital Budget Application.[11,12]

6.1 Pre-Contingency

Load flow results for 2033 for the current pre-contingency system configuration are shown in Table 14. No overloads were observed.

11 Due to ongoing issues surrounding the installation of the spare BBK transformer, Hydro is re-assessing this option and will notify Newfoundland Power of any changes to the long-term plan.

12 The following NP local generating plants were modeled as "on" for the Stephenville-Bottom Brook loop: Lookout Brook, Rose Blanche, Port-Aux-Basque diesel, mobile diesel (MD3) and mobile gas turbine (MGT).

Table 14 SVL-BBK 66kV Loop System Transformer Loading for 2033				
Station	**Unit**	**Max Rating (MVA)**	**P90 + 5.5%**	
			MVA	**%**
Stephenville	T3	66.6	38.0	57.1
Bottom Brook	T4	66.6	18.0	27.0

6.2 Single Line Outages (N-1)

Each 66kV transmission line within the SVL-BBK loop were individually opened in CYME to observe effects during peak. The results are provided in Table 15 below.

Table 15 SVL-BBK 66kV Loop Effect of Single Line Outages	
Transmission Line	**Planning Criteria Violations?**
	P90 + 5.5%
400L / 404L	No
401L / 405L / 406L	No
TL209	No

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.

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 2033. 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 SVL-T3 and BBK-T4; loading results for the simulated outages for the P90 + 5.5% case are found in Table 16.

Table 16 SVL-BBK 66kV Loop System Transformer Loading Following XFMR Loss P90 + 5.5% Scenario						
Station	**Unit**	**Max Rating (MVA)**	**P90 + 5.5% (No SVL-T3)**		**P90 + 5.5% (No BBK-T4)**	
			MVA	**%**	**MVA**	**%**
Stephenville	T3	66.6	*Out-of-service*		55.8	83.8
Bottom Brook	T4	66.6	60.9	91.4	*Out-of-service*	

7.0 Holyrood – Hardwoods 66kV Loop

The Holyrood – Hardwoods Loop ("HRD-HWD") is comprised of a 66kV section that runs through the St. John's Area between the Holyrood Substation and the Hardwoods Substation. 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 all CYME modeling was completed with 27MW of Fermeuse Wind disconnected.[13]

7.1 Pre-Contingency

Load flow results for 2033 for the current pre-contingency system configuration are shown in Table 17.

Table 17 HRD-HWD 66kV Loop System Transformer Loading for 2033				
Station	**Unit**	**Max Rating (MVA)**	**P90 + 5.5%**	
			MVA	**%**
Holyrood	T5	25	20.9	83.6
	T10	25	20.3	81.2
Hardwoods	T1	125	95.0	76.0
	T2	66.6	48.4	72.7
	T3	66.6	52.4	78.7
	T4	125	94.3	75.4

13 The following local generating plants were modeled as "on" for the Hardwoods-Oxen Pond loop: Cape Broyle, Horsechops, Mobile, Morris, Petty Harbour, Pierre's Brook, Rocky Pond, Seal Cove, Topsail, and Tors Cove. The HRD diesel units were modeled as "off".

7.2 Single Line Outages (N-1)

Each 66kV transmission line within the HRD-HWD loop were individually opened in CYME to observe effects during peak. The results are provided in Table 18.

Table 18
HRD-HWD 66kV Loop System
Effect of Single Line Outages to XFMR Loading and System Voltages

Transmission Line	Planning Criteria Violations?
	P90 + 5.5
4L / 25L	No
13L	No
15L / 19L / 54L / 69L	No
18L / 72L / 73L	No
38L / 51L / 52L	No
49L / 79L	No

7.3 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 2033. 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 HRD-T5 and HWD-T1. Loading results for the simulated outages during the P90 + 5.5% case are presented in Table 19.

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Table 19
N-1 Contingency HRD-HWD 66kV Loop Loading Following XFMR Loss
P90 + 5.5% Scenario

Station	Unit	Max Rating (MVA)	P90 + 5.5% (No HRD-T5)		P90 + 5.5% (No HWD-T1)	
			MVA	%	MVA	%
Holyrood	T5	25	*Out-of-service*		23.6	94.4
	T10	25	27.5	110	22.9	91.6
Hardwoods	T1	125	97.8	78.2	*Out-of-service*	
	T2	66.6	51.8	77.8	63.0	94.6
	T3	66.6	54.0	81.1	68.1	102
	T4	125	97.1	77.7	122.4	97.9

As shown in Table 19, an overload to HRD-T10 was observed with HRD-T5 out of service for the P90 + 5.5% case. Similarly, an overload to HWD-T3 was observed with HWD-T1 out of service.

To mitigate the overload to HRD-T10 following a loss of HRD-T5, 38L was opened in HRD for the P90 + 5.5% scenario. See Table 20. It should be noted that opening 38L while HRD-T5 is out of service results in the 66kV bus at HRD to be supplied from HWD.

To mitigate the overload to HWD-T3 following a loss of HWD-T1, a voltage management scheme at HWD was implemented. See Table 20

Table 20
HRD-HWD 66kV Loop System Transformer Loading Following XFMR Loss
P90 + 5.5% Scenario (MITIGATED)

Station	Unit	Max Rating (MVA)	P90 + 5.5% (No HRD-T5) Open 38L		P90 + 5.5% (No HWD-T1) HWD 66kV @ 1.00pu	
			MVA	%	MVA	%
Holyrood	T5	25	*Out-of-service*		24.3	97.2
	T10	25	0	0	23.6	94.4
Hardwoods	T1	125	105.5	84.4	*Out of Service*	
	T2	66.6	53.8	80.7	60.8	91.3
	T3	66.6	58.3	87.5	65.8	98.8
	T4	125	104.7	84.8	118.2	94.6

8.0 Summary

A summary of CYME load flow results for each loop outlined in this report are as follows:

- HWD-OPD 66kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 5.5% load scenario.
  - Disconnecting 30L during the P90 + 5.5% scenario resulted in an overload to 14L. Disconnecting 14L results in additional power flow over adjacent lines to all be within winter ampacity ratings.
  - A loss of either HWD-T3 or OPD-T1 during the P90 + 5.5% load scenario resulted in various transformer overloads in HWD and OPD at normal operating voltages. All observed overloads could be mitigated in CYME by implementing a voltage management scheme at HWD, as well as a 25MW load curtailment at MUN.
- HRD-WAV 66/138kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 5.5% load scenario.
  - Overloads to HRD-T6 and HRD-T7 were observed following the loss of HRD-T8 during the P90 + 5.5% scenario. This overload was mitigated in CYME by opening 39L in HRD.
  - An overload to BRB-T3 was observed following the loss of BRB-T2 during the P90 + 5.5% scenario. This overloaded was mitigated in CYME by opening 48L in BRB.
- SUN-STB 138kV Loop
  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 5.5% load scenario[14].
  - Potential undervoltages to transmission lines in the Central Newfoundland area were observed when 124L was disconnected during the P90 + 5.5% scenario. All observed undervoltages were able to mitigated in CYME by dispatching 25MW of thermal generation at WES.

[14] This assumes the construction of a new 138kV transmission line between LEW and BOY prior to 2033 to mitigate existing 66kV voltage violations at BOY, SUM, and TWG.

  - Potential undervoltages to transmission lines in the Burin Peninsula area were observed when either TL-212 or TL-219 were disconnected during the P90 + 5.5% scenario. All observed undervoltages were able to mitigated in CYME by dispatching 25MW of thermal generation at GRH.

  - An overload to SSD-T1 was observed following a loss of SSD-T4 during the P90 + 5.5% scenario. The overload was able to be mitigated in CYME by dispatching 25MW of thermal generation at both WES and GRH, as well as by opening 146L.

  - An overload to STB-T2 was observed following a loss of STB-T1 during the P90 + 5.5% scenario. The overload was able to be mitigated by dispatching 25MW of thermal generation at both WES and GRH.

- STV-BBK 66kV Loop

  - No overloads or planning criteria violations were observed during the pre- or post-contingency analysis of the P90 + 5.5% load scenario.

- HRD-HWD 66kV Loop

  - No overloads or planning criteria violations were observed during the pre-contingency P90 + 5.5% load scenario.

  - No overloads or planning criteria violations were observed with any single transmission line disconnected in CYME during the P90 + 5.5% load scenario.

  - An overload to HRD-T10 was observed following the loss of HRD-T5 during the P90 + 5.5% scenario. The overload could be mitigated by disconnecting 38L in HRD, thereby supplying the HRD 66kV bus from HWD.

  - An overload to HWD-T3 was observed following the loss of HWD-T1 during the P90 + 5.5% scenario. The overload was mitigated by implementing a voltage management scheme at HWD.