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May 15, 2020

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

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Reliability and Resource Adequacy Study Review – Near-Term Reliability Report – May 2020

Further to the Board of Commissioners of Public Utilities' ("Board") correspondence of October 13, 2016, requesting semi-annual reports on May 15 and November 15 each year on generation adequacy for the Island Interconnected System, enclosed please find one original plus eight copies of Newfoundland and Labrador Hydro's ("Hydro") report entitled "Near-Term Reliability Report."

This report reflects the Board's correspondence of March 5, 2020, in which it was requested that the report be prepared to consider system reliability in the event the LIL remains unavailable to June 1, 2021 and June 1, 2022.

Additionally, as committed in Hydro's correspondence of February 25, 2020, Attachment 1 to this report provides the Emergency Response Plan ("ERP") prepared by Nalcor Energy Power Supply for the Labrador Island Link overhead transmission lines to be in operation in advance of winter 2020-21.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd

Encl.

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Randy Dillon, Town of Happy Valley-Goose Bay

Near-Term Reliability Report

May 15, 2020

A report to the Board of Commissioners of Public Utilities

Contents

List of Attachments

1.0 Introduction

Supply adequacy in advance of the availability of full production from the Muskrat Falls Generating Station ("MFGS") remains a critical consideration for Newfoundland and Labrador Hydro ("Hydro") and its stakeholders. The enclosed assessment of near-term resource adequacy provides an in-depth view of system risks and mitigating measures to ensure customer requirements are met through the full system transition.

This report discusses the near-term resource adequacy and reliability of the Newfoundland and Labrador Interconnected System ("NLIS") for the study period, a 5-year horizon from 2020–2024, and provides the results of the probabilistic resource adequacy assessment for the NLIS for the study period. The analysis was conducted consistent with the methodology proposed in the North American Electric Reliability Corporation ("NERC") "Probabilistic Assessment Technical Guideline Document" that provides modelling "*practices, requirements and recommendations needed to perform high-quality probabilistic resource adequacy assessments.*"[1]

The reliability indices in this near-term report include both annual and monthly Loss of Load Hours ("LOLH"), Expected Unserved Energy ("EUE"), and Normalized EUE[2] for a five-year period. The analysis considers the different types of generating units (i.e., thermal, hydro, and wind) in Hydro's fleet, firm capacity contractual sales and purchases, transmission constraints, peak load, load variations, load forecast uncertainty, and demand side management programs. Similar to previous analyses, a range of projected availabilities was considered for the Holyrood Thermal Generating Station ("Holyrood TGS").

The *"*Probabilistic Assessment Technical Guideline Document" suggests a more granular view of resource adequacy, focusing on monthly and annual LOLH and EUE reporting. By conducting this type of analysis, the impact of system changes can more easily be observed than by using an annual analysis only. As LOLH and EUE do not currently have generally acceptable criterion, unlike the generally accepted LOLE criterion of 0.1, the quantified results are presented to show how loss of load changes based on system conditions rather than for comparison against a threshold.

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[1] "Probabilistic Assessment Technical Guideline Document," North American Electric Reliability Corporation, August 2016.

[2] Normalized EUE provides a measure relative to the size of the assessment area. It is defined as: [(Expected Unserved Energy)/(Net Energy for Load)] x 1,000,000 with the measure of per unit parts per million.

The granular near-term view provides insight into the impact of seasonal load and generation variations on supply events. This can be used to further inform decisions on the most appropriate resource options as system requirements evolve.

Given the current evolving nature of the NLIS, an analysis was conducted for each of the next five years (2020–2024) to provide the Board of Commissioners of Public Utilities ("Board") with insight into the evolution of system reliability as the Muskrat Falls Project assets are reliably integrated. In correspondence dated March 5, 2020, the Board requested that this report include a detailed plan and schedule detailing all activities required to ensure winter 2020–2021 service reliability under the assumption that the LIL will not be available during some or all of that period, as well as similar analysis for winter 2021–2022 on the same basis. Further, the Board requested that the supporting analysis include the following assumptions:

- Labrador Island Link ("LIL") unavailability until June 1,2021 and June 1,2022;
- Expected capacity assistance available;
- Expected available import power over the Maritime Link; and
- Holyrood TGS thermal Derated Adjusted Forced Outage Rates ("DAFORs") of 15%, 18% and 20%.

These assumptions form the basis of the analysis presented in this report. Additional detail on activities required to ensure reliable service through the 2020–2021 winter operating season are provided in Section 7.

2.0 Modelling Approach

The analysis in this report has been completed using Hydro's reliability model. This model has been used to assess system reliability since the Reliability and Resource Adequacy Study, filed in November 2018 ("2018 Filing"), with updates to reflect current system assumptions. A detailed discussion of the initial modelling approach used can be found in Volumes I and II of the 2018 Filing. A discussion of changes to the model from the 2018 Filing can be found in Volume I of the "Reliability and Resource Adequacy Study 2019 Update", filed in November 2019 ("2019 Update"), and the "Near Term Generation Adequacy Report", filed on May 15, 2019.

Transmission system adequacy is assessed separately in accordance with Transmission Planning Criteria; these assessments are posted publically on the Newfoundland and Labrador System Operator ("NLSO") Open Access Same-Time Information System ("OASIS") website.[3]

3.0 Asset Reliability

On a quarterly basis, reports are filed with the Board which include actual forced outage rates and their relation to:

- the rolling 12-month performance of its units,[4]
- past historical rates; and
- assumptions used in assessment of resource adequacy.

The most recent report was submitted on April 30, 2020, for the quarter ending March 31, 2020. These reports detail unit reliability issues experienced in the previous 12-month period and compare performance for the same period year-over-year.

Hydro continues to take actions to address repeat performance issues by conducting broader reviews that frequently involve external experts, addressing issues with urgency, and placing an increased focus on asset reliability.

These actions are intended to support reliable unit operation and increase the likelihood of improved reliability in near-term operating seasons.

3.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since filing its 2019 Update. Updates on these items, as well as any additional items which may impact asset performance in the near-term, are provided in this report. The intention is to ensure issues affecting reliability have been appropriately addressed, as issues that are recurring in nature can have a significant impact on unit reliability if not managed properly. The information included in sections 3.1.1 through 3.1.3 of this report provides an overview of the repeat or broader issues. Isolated equipment issues (i.e., those that occur once on a particular unit) are also investigated, with the root cause identified and corrected. These types of issues

[3] NLSO Standard Transmission Planning Criteria Doc # TP-S-007," Newfoundland and Labrador Hydro, May 11, 2018.
[4] Quarterly Report on Performance of Generating Units.

are reflected in the calculation of DAFOR and Derated Adjusted Utilization Forced Outage Probabilities ("DAUFOP").

The following sections provide a description of issues, both asset- and condition-based, that have previously affected generating unit reliability, as well as the current status of those issues and the actions taken to mitigate against future reliability impacts. The scope is not limited to generating assets (e.g., penstock, boiler tubes), but also considers environmental challenges impacting operations (e.g., frazil ice conditions). As part of this exercise the following items have been identified, grouped by facility type:

- Hydraulic Facilities: Continued monitoring (Bay d'Espoir penstocks and Upper Salmon rotor rim key cracking); ongoing (Granite Canal control system); and resolved (Hinds Lake rotor resistance) and;
- Thermal Facilities: Continued monitoring (unit boiler tubes); ongoing (variable frequency drives); and
- Gas Turbines: Resolved (Stephenville End B Vibration).

Any factors that impact unit availability, including those that have historically contributed to unit outages, are reflected in the DAFOR and DAUFOP assumptions selected for each asset.

3.1.1 Hydraulic

Bay d'Espoir Penstocks

Condition assessments of Bay d'Espoir Penstocks 1, 2, and 3 were conducted in 2018, which included the completion of three reports prepared by a third-party consultant. These reports have been filed with the Board.[5]

In response to previous penstock failures an annual internal inspection program was implemented for Penstocks 1 to 3 in Bay d'Espoir as part of an ongoing effort to monitor the performance of the penstocks and ensure reliability in the short-term. The 2019 annual inspections of Penstocks 2 and 3 were completed during the maintenance season and did not identify any major defects or areas of concern. The inspection of Penstock 1 had been scheduled for October 2019. Following the failure on

[5] "Bay d'Espoir Level II Condition Assessment of Penstock No. 1, 2, and 3," Hatch Ltd., rev. 0, December 13, 2018; "Final Report for Condition Assessment and Refurbishment Options for Penstocks 1, 2 and 3," Hatch Ltd., rev. 0, March 28, 2019; and "Final Report for Penstock No.'s 1, 2 and 3 Life Extension Options," Hatch Ltd. rev. 0, July 26, 2019.

September 22, 2019, the inspection of Penstock 1 was advanced and completed while the penstock was undergoing repairs.[6] The results of the 2019 inspection revealed no major defects or areas of concern outside of the ruptured zone.

Although the inspection did not reveal any immediate concerns, Penstock 1 is nearing the end of life. To mitigate potential impacts should another leak in Penstock 1 occur, proactive measures have been taken to reduce downtime. These actions include having an inventory of long lead time materials available (e.g., rolled steel plate), ensuring availability of welding resources, and engagement of an additional engineering consultant to ensure development of an appropriate long-term plan. Modifications to the Automatic Generator Control application in Hydro's Energy Management System designed to limit the amount of rough zone operation have also been implemented for Units 1-6 at Bay d'Espoir. A more prescriptive operating regime has been implemented for Units 1 and 2 at Bay d'Espoir, given the condition of Penstock 1. In this operating regime, once dispatched, Units 1 and 2 are limited to a minimum unit loading of 50 MW and are not cycled or shut down as part of normal system operations.

Since the time of the previous filing, and in response to the most recent September 2019 failure of Penstock 1, SNC-Lavalin was engaged to complete an independent, detailed failure analysis of the most recent rupture, as well as an engineering review of the work previously completed by Hatch. The results of this failure analysis and engineering review are presently being reviewed prior to filing with the Board.

The 2020 inspections of Bay d'Espoir Penstocks 1 to 3 have been scheduled. The inspection of Penstock 3 was scheduled for completion in May; however, due to ongoing concerns and limitations resulting from COVID-19, the inspection has been cancelled for 2020. This decision was made in consultation with the consultant responsible for the penstock inspections and based on the results from the 2019 inspection and the outcomes of the failure analysis of previous failures. It was determined that Penstock 3 is safe for continued operation until the next scheduled inspection in 2021. The scheduled 2020 inspections for Penstocks 1 and 2 are not likely to be affected by COVID-19 as timelines and pre-planning will allow them to proceed. These inspections are currently scheduled for July and October, respectively.

[6] On September 22, 2019, a failure of Bay d'Espoir Penstock 1 resulted in a forced outage to Units 1 and 2.

Hinds Lake Rotor Resistance

The Hinds Lake unit was removed from service on August 18, 2019 for a planned outage to complete the required rewind of the rotor poles.[7] The planned rewind was successfully completed with the unit returning to service on November 22, 2019. This issue is considered resolved.

Granite Canal Control System

A thorough engineering assessment of the system in response to control system malfunctions experienced when remotely starting and/or stopping the Granite Canal unit has been completed. Modifications to equipment, as well as minor logical changes were implemented and additional findings have been compiled and are currently under review by the OEM and Hydro Engineering Services. An operating project is planned for 2020 to address the additional findings from 2019 and implement any further hardware or logic changes required. If necessary, any required capital work will be proposed as part of the capital budget process.

Upper Salmon Rotor Key Cracking

In 2018, the rotor rim keys on the Upper Salmon generating unit were replaced during the unit annual maintenance outage. As per consultation with the OEM, Hydro has continued to schedule and conduct regular inspections of the new rotor rim keys at Upper Salmon and will continue to monitor this situation throughout the anticipated wear-in period of the new keys and assess the effectiveness of the replacement keys. Since the 2019 Update, inspections have continued and the development of new cracks has been decreasing, with no new cracks discovered in the three most recent inspections. As a result, the time between inspections has been increased from four weeks to six weeks.

3.1.2 Thermal

Unit Boiler Tubes

Each of the three thermal generating units at the Holyrood TGS has a boiler that contains tubes. Boiler tube failures are a common issue in thermal power plants due to the inherent design, which requires relatively thin walls for heat transfer that are subjected to high temperatures and stresses. Boiler tubes are inspected on an annual basis to verify their condition and to identify trends.

To mitigate the possibility of tube failures, Hydro conducts an annual tube inspection program, most recently completed during the 2019 annual outages and planned for completion during the 2020 annual

[7] Resistance readings from the Hinds Lake rotor, as measured during annual maintenance inspections, had trended down over the past several years, approaching the critical level of 0.14 Mohms as established by the Original Equipment Manufacturer.

outages. Hydro has determined that boiler tube sections, as a whole, are in good condition. Tube failures continue to pose a risk, particularly given the age of the Holyrood TGS boilers. Hydro maintains a thorough selection of spare tube material and has an established contract with Babcock & Wilcox for the provision of emergency repairs in the event of tube failures. As such, should a tube failure occur, the expected return to service time is accounted for in the projected DAFOR targets.

Variable Frequency Drives

Forced draft fans provide combustion air required for boiler operation at the Holyrood TGS. The Variable Frequency Drives ("VFD") were installed to more efficiently vary the amount of air required based on generation need. This reduces auxiliary power requirements and results in fuel savings.

Hydro has entered into a service agreement with Siemens and preventive maintenance work was completed by Siemens in 2018 and 2019 to address issues that have been encountered through unit operation. Operating strategies have also been implemented to reduce the likelihood of VFD failures, such as pre-energizing VFD equipment prior to unit start-ups.

At the start of the 2019–2020 operating season, issues with power cell failures were encountered when re-energizing VFDs after an extended shutdown.[8] New strategies intended to mitigate re-energization failures are planned to be implemented during the 2020 maintenance work. This includes erecting temporary enclosures while the units are off-line to control ingress of moisture and contamination to the drives. The inventory of spare cells has also been increased from 9 to 15.

During the 2019–2020 operating season there were two VFD related failures that led to unit trips. In both cases the unit was returned to service within a few hours.[9]

3.1.3 Gas Turbines

Engine Vibration End B at Stephenville

The Stephenville Gas Turbine ("Stephenville GT") was derated to 25 MW following its return to service after completion of its annual maintenance outage on June 14, 2019 due to a planned overhaul of one of the engines at an off-site facility. Upon return from the overhaul facility, the engine was reinstalled in End B, however the engine tripped due to excessive vibration during commissioning on November 18,

[8] Eight cells failed during power-up after completion of the 2019 annual preventative maintenance program and five additional cells failed on unit start-up.
[9] On October 30, 2019, there was a trip on the Unit 2 east VFD. During this trip, the 4160 V breaker failed to open, which caused an air damper to fail to close, disrupting proper airflow to the boiler and leading to a unit trip. On January 28, 2020, there was a trip on the Unit 2 west VFD due to the failure of a power cell.

2019. An internal inspection of the engine determined that the vibration was the result of a high-pressure turbine blade tip rubbing on its casing. The inspection also revealed internal damage to the on-engine fuel pump gearbox. As a result of this damage, the engine was removed from End B and sent back to the overhaul facility for repair.[10] Stephenville End B remained out of service until February 1, 2020 as the spare engine for this unit was also out for service. Upon return, the spare engine was successfully installed and commissioned, returning the Stephenville GT to full capacity. Hydro considers this issue to be resolved.

3.2 Selection of Appropriate Performance Ratings

3.2.1 Consideration of Asset Reliability in System Planning

Hydro's asset reliability is a critical component in determining its ability to meet planning criteria for the NLIS. As an input to the assessment of resource adequacy, unit forced outage rates ("FOR") provide a measure of the expected level of availability due to unforeseen circumstances.[11] Assumptions on FORs of generating units in this analysis are consistent with the FORs used in the 2019 Update.[12]

The forced outage rates used in Hydro's reliability analysis vary by asset class, ownership, and condition. Appropriate FORs were determined based on historical data, where available, or the most recent industry average. The FOR is calculated using different metrics depending on the primary operating mode of the units. For units that primarily operate on a continuous basis, specifically units at Holyrood TGS and hydroelectric units, the FOR is based on the historical DAFOR. For units that primarily operate as peaking units, specifically gas turbine units, the FOR is based on the historical DAUFOP. Analysis was performed for a range of Holyrood TGS DAFOR assumptions to provide an indication of the sensitivity of supply adequacy to changes in Holyrood TGS availability. Industry information made available through the Canadian Electricity Association ("CEA") and NERC is used for units not owned by Hydro.

FOR assumptions are developed annually to incorporate the most recent data available. A detailed description of the development of the FOR assumptions used is found in Volume III, Attachment 1 of the 2019 Update. Table 1 summarizes the projected availability of Hydro's generating assets considered in

[10] This unit was repaired and returned to Hydro on February 19, 2020 and is currently in storage in Stephenville for use as a spare unit.

[11] For the purposes of the 2019 Update, forced outage rate refers to an input to the reliability model, which represents the percentage of hours in a year when a unit is unavailable.

[12] The annual update of FOR assumptions will be completed for the 2020 Update to the Reliability and Resource Adequacy Study.

the assessment of near-term supply adequacy. These projections of asset reliability include appropriate consideration of asset availability and deration.

Table 1: Forced Outage Rates for Hydro-Owned Assets

Asset	Reliability Metric
Hydraulic Units	DAFOR = 2.8%
Holyrood Thermal Units – base assumption	DAFOR = 15%
Holyrood Thermal Units – sensitivity assumptions	DAFOR = 18%, 20%
Holyrood Gas Turbine	DAUFOP = 1.7%
Happy-Valley Gas Turbine	DAUFOP = 9.8%
Stephenville Gas Turbine	DAUFOP = 30%
Hardwoods Gas Turbine	DAUFOP = 30%
Diesels	DAUFOP = 6.2%

With respect to the LIL, once modelled as in service, the forced outage rate is modelled with a declining FOR in order to capture any testing activities and potential operational unknowns during the first years of operation.[13] As the LIL and the generating units at Muskrat Falls are expected to be in service prior to June 2021, for the purpose of this analysis, the LIL is assumed to be available at its full capacity on the in-service date, supported by the full availability of the Muskrat Falls generating units. It is assumed that delivery of the Nova Scotia Block[14] will commence once the LIL is in-service.

For units not owned by Hydro, the forced outage rates used in modelling are determined using industry averages provided in the CEA Generating Equipment Reliability Information System and the NERC Generating Availability Data System. Forced outage rates used for assets owned by a third-party in this analysis are presented in Table 2.

Table 2: Forced Outage Rates for Third-Party-Owned Assets

Asset	Reliability Metric
Hydraulic Units	DAFOR = 5.7%
Gas Turbines	DAUFOP = 13.6%
Corner Brook Cogen.	DAUFOP = 15.8%

[13] In year 1 of operation, the monopole forced outage rate is assumed to be 10% for each pole. The forced outage rate assumption decreases to 2.5% in year 2, 1% in year 3, and finally to the long-term forced outage rate of 0.556% per pole from year 4 onwards.

[14] The Nova Scotia Block is a firm annual commitment of 980 GWh, to be supplied from the MFGS on peak.

Hydro models wind generation stochastically using probability distribution functions developed for summer and winter generation at each of the Fermeuse and St. Lawrence generating facilities.

Based on Hydro's experience with securing market purchases to date, import scenarios are contemplated as sensitivities to cases considered in this report; that is firm imports of 50 MW and 100 MW from December to March in winters before the LIL is placed in service, with an associated FOR intended to serve as proxy for anticipated potential interruptions to the import. Since the availability of these contracts requires a counterparty to provide firm capacity, there is no guarantee that these contracts would be available. The analysis demonstrates the effect on the system if the capacity was available in the requested amounts.

3.3 Asset Retirement Plans

3.3.1 Holyrood Thermal Generating Station

The Holyrood TGS Units 1 and 2 were commissioned in 1971 and Unit 3 was commissioned in 1979. The three units combined provide a total firm capacity of 490 MW. In advance of its planned retirement as a generating facility, the Holyrood TGS continues to be fully operational. Hydro has always intended to maintain up to a two-year period of standby operation of the Holyrood TGS during early operation of the Muskrat Falls Project Assets. During this period of standby the Holyrood TGS units would be fully available for generation. In correspondence dated February 14, 2020, Hydro advised the Board of an extension to the operations of the Holyrood TGS as a generating facility to March 31, 2022. For the purposes of this analysis, in the scenarios where the LIL remains unavailable until June 1, 2022[15] it is assumed for the purposes of this analysis that the Holyrood TGS could remain available as a generating facility until March 31, 2023. Beyond the retirement date, Unit 3 at the Holyrood TGS will continue to operate as a synchronous condenser, while Units 1 and 2 are scheduled to be shut down and decommissioned.

3.3.2 Hardwoods and Stephenville Gas Turbines

The Stephenville Gas Turbine ("Stephenville GT") consists of two 25 MW gas generators that were commissioned in 1975. The Hardwoods Gas Turbine ("Hardwoods GT") consists of two 25 MW gas generators that were commissioned in 1976. Each plant provides 50 MW of firm capacity to the system. These units were designed to operate in either generation mode to meet peak and emergency power

[15] As per March 5, 2020 request by the Board.

requirements or synchronous condense mode to provide voltage support to the Island Interconnected System ("IIS"). These units were planned to be retired in 2021.

As identified in the most recent transmission planning assessment[16], following the retirement of the Stephenville GT, backup supply for the area will be addressed by the addition of a 230/66 kV, 40/53.3/66.7 MVA power transformer at the Bottom Brook Terminal Station. This addition will provide capacity via the 66 kV network in the event of the loss of the existing 230/66 kV transformer T3 at the Stephenville Terminal Station or the loss of the 230 kV transmission line TL209. This project is in final stages of consideration for inclusion in Hydro's 2021 Capital Budget Application. As this project will take two years to complete, the Stephenville GT will be retired following completion of this project in 2023.

With respect to the Hardwoods GT, operating hours and generation at this facility has decreased materially in the past two years from levels observed in 2014 through 2018 and asset availability at these facilities is much improved over levels previously observed.[17] Given continued uncertainty regarding the reliable in-service of the LIL, Hydro proposes to retain the Hardwoods GT in service until the LIL is proven reliable. Hydro will continue to model these assets with a DAUFOP of 30% to ensure there is not an overreliance on these assets in the near-term to maintain the reliability of the system. To ensure an appropriate balance of cost and reliability in this matter, Hydro will undertake necessary preventive and corrective maintenance work to ensure these units are available to the IIS; however, Hydro will re-evaluate the decision to retain all or portions of the assets in service should extensive maintenance or incremental capital expenditures are required to facilitate this life extension.

As such, for the purposes of this report it is assumed that the Stephenville GT will be retired in 2023 and the Hardwoods GT will be retired on the same schedule as the Holyrood TGS. This is modelled as March 31, 2022 when the LIL is modelled as in service in June 2021, and March 31, 2023 when the LIL is modelled as in service in June 2022.

4.0 Load Forecast

4.1 Load Forecasting

The purpose of load forecasting is to project electric power demand and energy requirements through future periods. This is a key input to the resource planning process, which ensures sufficient resources

[16] The 2020 Final Annual Planning Assessment was posted to the NLSO OASIS site on May 7, 2020.

[17] This reduction in the requirement to operate is primarily attributed to the high degree of reliability observed at Holyrood TGS, the availability of the Maritime Link, and Hydro's ability to use a portion of the capacity available under its Capacity Assistance agreement with Corner Brook Pulp and Paper as ten-minute reserve.

are available consistent with applied reliability standards. The load forecast is segmented by the IIS and Labrador Interconnected System ("LIS"), rural isolated systems, as well as by utility load[18] and industrial load[19]. The load forecast process entails translating an economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems. For the current analysis, Hydro has updated its provincial load forecast outlook to reflect the latest available load forecast information from its industrial customers, Newfoundland Power, and Hydro's own rural service territories.

4.2 Economic Setting[20]

Newfoundland and Labrador remains in a transitionary phase, as major projects near completion and new developments wait to be realized.

In 2019, the provincial economy was positively influenced by increased oil production and increased mineral production. The Hebron oil project completed in late 2017 has transitioned to production phase with production volumes ramping up during 2019. Higher mineral production and exports in 2019 were largely due to increased iron ore output by the Iron Ore Company of Canada that rebounded after a two-month labour strike in 2018. The economy also benefitted from the activities associated with the reactivation of the Scully Mine in Labrador by Tacora and the Beaver Brook Antimony Mine on the Island.

Increased capital investment resulting from higher non-residential spending offset a decline in residential spending. Non-residential spending was led by expenditures on major projects while declines in residential spending resulted from lower housing starts. With the provincial Government's fiscal situation remaining relatively challenging and an overall muted economic environment, the underlying local market conditions for electric power operations suggest stable or possible modest decline for the near term followed by a return to increasing power requirements once economic conditions improve.

[18] Residential and general service loads of Newfoundland Power and Hydro
[19] Larger direct customers of Hydro such as Corner Brook Pulp & Paper Ltd ("CBPP"), North Atlantic Refining Ltd. ("NARL"), Vale Newfoundland and Labrador Limited ("Vale"), Praxair Canada Inc., Iron Ore Company of Canada, and Tacora Resources Inc. ("Tacora")
[20] The economy and forecast load requirements reflected in this report do not include possible medium-term impacts associated with the COVID-19 pandemic. With respect to the pandemic, Hydro has modelled a change to 2020 energy requirements only, associated with the known impacts of COVID-19 (e.g. reduced requirements at NARL). These impacts are currently under study. Economic commentary reflects "The Economic Review 2019, Government of Newfoundland & Labrador"

4.3 Forecast Load Requirements

The customer load requirement component of Hydro's five-year load forecast was developed using forecasted load requirements provided by Hydro's industrial customers and Newfoundland Power's energy forecast, as well as Hydro's load forecast for its rural service territories and for Newfoundland Power peak demand.[21] Hydro's forecast annual peak demand requirements for the Newfoundland Power system are approximately 40-50 MW higher than the peak demand forecast provided by Newfoundland Power.[22] Hydro relied on these inputs to determine a five-year forecast of customer energy and coincident demand for the IIS, LIS, and NLIS.

Changes in forecast load requirements since the filing of the 2019 Update include a change to 2020 energy requirements, associated with the known impacts of COVID-19, and minor changes in forecast IIS power and energy requirements across the medium term. Forecast IIS peak demand requirements changes are less than 0.5% through the medium term, with forecast energy requirements modestly lower (-2%) through the medium term, as compared to the forecast which supported the 2019 Update. The reduction in forecast IIS energy requirements primarily reflects changes to forecast energy requirements for Newfoundland Power.[23] Forecast power and energy requirements for the IIS industrial customers remains on par with industrial customers' expectations included in the 2019 Update. Forecast IIS utility power and energy requirements remain largely unchanged from that previously forecast and continue to reflect a mostly stagnant outlook for the provincial economy.

In Labrador, the re-activation of Scully Mine by Tacora has resulted in increased power requirements on the LIS. Year-to-date power requirements indicate loads to be comparable with the former operator's power requirements. Forecast LIS utility power and energy requirements now reflect load forecast updates completed by Hydro in April 2020 and includes Hydro's latest forecast of approved new customer loads. As with the IIS utility power and energy requirements, the LIS utility power and energy requirements in the medium term remain largely unchanged from previously forecast. The forecast for LIS industrial firm power requirements are slightly reduced in the near term and slightly increased beyond the near term. These near-term forecast changes reflect the unresolved transmission supply constraints to the western Labrador system while slightly higher requirements are forecast beyond the near term, assuming the transmission supply constraints are resolved.

[21] Hydro's rural service territory includes independently completed load forecasts for the Island Interconnected rural service territory, the Labrador East rural service territory and the Labrador West rural service territory.
[22] Newfoundland Power forecast, April 29, 2020.
[23] Newfoundland Power forecast, April 29, 2020.

The demand forecasts by system are provided in Tables 3 to 5.

Table 3: Island Interconnected System Peak Demand Forecast (MW)

	P50			
	2021	**2022**	**2023**	**2024**
Utility	1,484	1,485	1,495	1,505
Industrial Customer	178	180	180	180
IIS Customer Coincident Demand	**1,662**	**1,665**	**1,674**	**1,685**
IIS Transmission Losses and Station Service	76	110	109	109
Total IIS Demand	**1,738**	**1,775**	**1,783**	**1,794**

Table 4: Labrador Interconnected System Peak Demand Forecast (MW)

	P50			
	2021	**2022**	**2023**	**2024**
Utility	143	143	143	144
Industrial Customer	277	277	298	298
LIS Customer Coincident Demand	**420**	**421**	**441**	**442**
LIS Transmission Losses and Station Service	26	26	28	28
Total LIS Demand	**446**	**447**	**469**	**470**

Table 5: Newfoundland and Labrador Interconnected System Peak Demand Forecast (MW)

	P50			
	2021	**2022**	**2023**	**2024**
NLIS Customer Coincident Demand	2,063	2,057	2,063	2,067
NLIS Transmission Losses and Station Service	101	134	133	133
Total NLIS Demand	**2,164**	**2,191**	**2,196**	**2,200**

5.0 System Energy Capability

In order to reliably serve its customers, Hydro maintains minimum storage limits to ensure that it is capable of meeting customer energy requirements. In the current system, these limits represent the point at which Holyrood generation would be required to be maximized to ensure Hydro could continue to meet customer requirements in consideration of the historical dry sequence. The targets do not consider the availability of imports, though imports can provide an additional opportunity to supplement energy in storage and economically reduce the amount of thermal generation required to maintain sufficient energy in storage. Regular assessments of storage at a reservoir level basis are also completed to ensure that each hydraulic generating unit remains capable of producing at full rated output through the winter period.

The most recent snow survey was completed in mid-March 2020. The survey indicated that, for the system as a whole, snow water equivalent (mm) was approximately 93% of average and equivalent energy (GWh) was approximately 94% of average. Spring freshet is in progress in the Long Pond Reservoir and is expected to continue in Long Pond and the remaining reservoir basins through May.

System energy in storage remained above the minimum storage target throughout winter 2019–2020. At the end of April 2020, the total system energy in storage was 854 GWh; 634 GWh above the minimum storage limit of 220 GWh for April 2020. Hydro is establishing minimum storage limits to April 30, 2021 in consideration of potential delays in the availability of the LIL to deliver energy to the IIS. This will help ensure sufficient storage to reliably serve customers should the LIL continue to be delayed beyond the fall of 2020. With the availability of thermal energy and access to external markets to provide the balance of load, the availability of energy in reservoir systems does not currently pose a risk to near-term resource adequacy.

6.0 Results

The following subsections provide a description of the eight scenarios considered and the anticipated system reliability in each scenario (i.e., LOLH, EUE, and normalized EUE results).

6.1 Scenario Analysis

Eight scenarios were analyzed to assess system reliability under a range of potential system conditions:

- **Scenario 1:** Assumes that the LIL will be available at full capacity on June 1, 2021. This case assumes a DAFOR of 15% for the Holyrood TGS and retirement of the Holyrood TGS and Hardwoods GT on March 31, 2022. No LIL deliveries are contemplated in advance of June 1, 2021.
- **Scenario 2:** Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 3:** Varies from Scenario 1 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 4:** Varies from Scenario 3 by including 50 MW of imports during the winter season.
- **Scenario 5:** Varies from Scenario 3 by including 100 MW of imports during the winter season.

- **Scenario 6:** Varies from Scenario 1 by considering the LIL to be available at full capacity on June 1, 2022, with retirement of the Holyrood TGS and Hardwoods GT on March 31, 2023. No LIL deliveries are contemplated in advance of June 1, 2022.
- **Scenario 7:** Varies from Scenario 6 by increasing the Holyrood TGS DAFOR to 18%.
- **Scenario 8:** Varies from Scenario 6 by increasing the Holyrood TGS DAFOR to 20%.
- **Scenario 9:** Varies from Scenario 8 by including 50 MW of imports during the winter season.
- **Scenario 10:** Varies from Scenario 8 by including 100 MW of imports during the winter season.

For scenarios 1 through 5 it is assumed that the contract for capacity assistance with Vale is renewed for the 2020–2021 winter operating season. For scenarios 6 through 10 it is assumed that the contract for capacity assistance with Vale is renewed for the 2021–2022 winter operating season.

6.2 Expected Unserved Energy and Loss of Load Hours Analysis

Sections 6.2.1 and 6.2.2 provide the results of the annual and monthly analysis, respectively.

6.2.1 Annual Assessment Results

Table 6 provides the annual LOLH, EUE and normalized EUE results. Note that the basis for comparison of results is Hydro’s existing LOLH criterion of not more than 2.8 hours per year. Hydro intends to migrate to its proposed criteria of 0.1 LOLE when the Muskrat Falls Project has been fully commissioned and thermal generation at the Holyrood TGS, Hardwoods GT, and Stephenville GT has been retired.

Where scenarios are no longer relevant (i.e., the increase in DAFOR for the Holyrood TGS no longer varies the LOLH or EUE once the plant has been is retired), the results have been noted as not applicable (“N/A”).

Table 6: Annual LOLH, EUE, and Normalized EUE Results

Reliability Metric					
LOLH (hours)	**2020[24]**	**2021**	**2022**	**2023**	**2024**
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0.66	2.45	0.27	0.52	0.49
S2: LIL 2021, Holyrood TGS DAFOR = 18%	0.92	3.79	0.29	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	1.19	4.82	0.28	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	0.71	2.69	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	0.41	1.45	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	0.66	3.23	2.61	0.37	N/A
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	0.92	4.81	4.02	0.38	N/A
S8: LIL 2022, Holyrood TGS DAFOR = 20%	1.19	6.16	5.07	0.39	N/A
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	0.71	3.45	2.91	N/A	N/A
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	0.41	1.90	1.64	N/A	N/A
EUE (MWh)	**2020**	**2021**	**2022**	**2023**	**2024**
S1: LIL 2021, Holyrood TGS DAFOR = 15%	37	130	29	52	45
S2: LIL 2021, Holyrood TGS DAFOR = 18%	55	204	29	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	71	265	29	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	40	139	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	23	69	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	37	173	138	34	N/A
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	55	260	219	37	N/A
S8: LIL 2022, Holyrood TGS DAFOR = 20%	71	341	281	39	N/A
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	40	182	151	N/A	N/A
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	23	93	80	N/A	N/A
Normalized EUE (ppm)	**2020**	**2021**	**2022**	**2023**	**2024**
S1: LIL 2021, Holyrood TGS DAFOR = 15%	3.4	12.0	2.7	4.9	4.2
S2: LIL 2021, Holyrood TGS DAFOR = 18%	5.2	19.0	2.7	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	6.7	24.5	2.7	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	3.7	12.8	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	2.1	6.4	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	3.3	16.0	12.7	3.3	N/A
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	5.3	24.1	20.2	3.4	N/A
S8: LIL 2022, Holyrood TGS DAFOR = 20%	6.8	31.7	25.9	3.6	N/A
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	3.7	16.8	14.0	N/A	N/A
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	2.1	8.6	7.4	N/A	N/A

[24] The results for 2020 are presented for the remainder of the year

Higher levels of LOLH and EUE are observed in all scenarios during 2021, resultant from the LIL being unavailable during the winter operating season, with both LOLH and EUE growing as the unavailability of Holyrood TGS increases. In Scenarios 1 through 5, the LOLH and EUE drop significantly once the LIL is in service in June 2021 and remain at acceptable levels through the remainder of the study period. In Scenarios 6 through 10, where the LIL remains unavailable until June 2022, the EUE and LOLH remain higher through 2022.

Based on these results, it can be observed that there is an increased risk of generation shortfall until the LIL is in service, with the amount of risk highly dependent on the availability of the Holyrood TGS. As demonstrated in Scenarios 4, 5, 9 and 10, imports over the Maritime Link could be used to mitigate the risk of generation shortfall. An import of 100 MW in on-peak hours from December to March would be sufficient to reduce the risk of generation shortfall to an acceptable level in the most onerous modelled scenario.

6.2.2 Monthly Assessment Results

Table 7 through Table 11 provides analyses of LOLH and EUE for each year by month. The monthly analyses provide additional detail that assists in examining the complexity of the changing power system that would not necessarily be apparent from an analysis of the annual results only. Completing monthly analyses allows for easier identification of changes in system behaviour. For example, if a system had a change in forecast peak demand with no resultant change in annual LOLH or EUE, the monthly analysis would indicate where differences in LOLH and EUE were anticipated, allowing for better understanding of the drivers of the annual results. This type of analysis is used by NERC-regulated utilities to complement long-term reliability assessments.

High values of LOLH and EUE are observed in all scenarios during the winter months of 2021, with both LOLH and EUE growing as the Holyrood TGS unavailability increases.

In Scenarios 1 to 5, LOLH and EUE are observed to decrease significantly as generation becomes available at the MFGS and the LIL enters normal operation, resulting in a low value of LOLH and EUE during the winter of 2021–2022 when Holyrood TGS and the LIL are both in-service. Once Holyrood TGS and the Hardwoods and Stephenville GTs are retired, LOLH increases but remains at acceptable levels through the study period.

In Scenarios 6 to 8, the LOLH and EUE remain high through the winter of 2021–2022. Similar to the results of Scenarios 1 through 5, the LOLH and EUE are very low during the period when both the LIL and the Holyrood TGS are in service, in this case winter 2022–2023, and rise once the Holyrood TGS and Hardwoods and Stephenville GTs are retired.

As seen in Scenarios 4, 5, 9 and 10, the import of firm energy over the Maritime Link produces a significant improvement in system reliability. This demonstrates that firm imports could be used to mitigate the increased risk of resource shortfalls if the LIL is delayed or if the Holyrood TGS or other generating assets were to perform more poorly than expected.

It is important to note that, given the conservative nature of this analysis, it has been assumed that the LIL will not be available in advance of June 2021. If the LIL is available, even at the level of availability experienced in the winter of 2018–2019, it would have a significant positive impact on system reliability.

Table 7: Monthly LOLH and EUE for 2020

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%					0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.64
S2: LIL 2021, Holyrood TGS DAFOR = 18%					0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.88
S3: LIL 2021, Holyrood TGS DAFOR = 20%					0.00	0.00	0.00	0.00	0.00	0.00	0.05	1.14
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports					0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.65
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports					0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.36
S6: LIL 2022, Holyrood TGS DAFOR = 15%					0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.64
S7: LIL 2022, Holyrood TGS DAFOR = 18%,					0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.88
S8: LIL 2022, Holyrood TGS DAFOR = 20%					0.00	0.00	0.00	0.00	0.00	0.00	0.05	1.14
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports					0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.65
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports					0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.36

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%					0	0	0	0	0	0	1	36
S2: LIL 2021, Holyrood TGS DAFOR = 18%					0	0	0	0	0	0	2	53
S3: LIL 2021, Holyrood TGS DAFOR = 20%					0	0	0	0	0	0	3	69
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports					0	0	0	0	0	0	3	37
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports					0	0	0	0	0	0	2	20
S6: LIL 2022, Holyrood TGS DAFOR = 15%					0	0	0	0	0	0	1	36
S7: LIL 2022, Holyrood TGS DAFOR = 18%,					0	0	0	0	0	0	2	53
S8: LIL 2022, Holyrood TGS DAFOR = 20%					0	0	0	0	0	0	3	69
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports					0	0	0	0	0	0	3	37
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports					0	0	0	0	0	0	2	20

Table 8: Monthly LOLH and EUE for 2021

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	1.13	0.77	0.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
S2: LIL 2021, Holyrood TGS DAFOR = 18%	1.77	1.18	0.81	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
S3: LIL 2021, Holyrood TGS DAFOR = 20%	2.22	1.52	1.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	1.22	0.84	0.60	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	0.69	0.43	0.30	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
S6: LIL 2022, Holyrood TGS DAFOR = 15%	1.18	0.78	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.70
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	1.73	1.21	0.80	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.06	1.00
S8: LIL 2022, Holyrood TGS DAFOR = 20%	2.25	1.55	1.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.07	1.25
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	1.22	0.84	0.60	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.71
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	0.69	0.43	0.30	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.40

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	61	39	29	0	0	0	0	0	0	0	0	1
S2: LIL 2021, Holyrood TGS DAFOR = 18%	97	61	45	0	0	0	0	0	0	0	0	1
S3: LIL 2021, Holyrood TGS DAFOR = 20%	124	82	58	0	0	0	0	0	0	0	0	1
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	63	43	32	0	0	0	0	0	0	0	0	1
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	33	20	15	0	0	0	0	0	0	0	0	1
S6: LIL 2022, Holyrood TGS DAFOR = 15%	64	40	28	0	0	0	0	0	0	0	2	39
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	95	62	43	0	0	0	0	0	0	0	3	57
S8: LIL 2022, Holyrood TGS DAFOR = 20%	126	81	57	0	0	0	0	0	0	0	3	74
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	63	43	32	0	0	0	0	0	0	0	3	41
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	33	20	15	0	0	0	0	0	0	0	3	22

Table 9: Monthly LOLH and EUE for 2022

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.24
S2: LIL 2021, Holyrood TGS DAFOR = 18%	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.25
S3: LIL 2021, Holyrood TGS DAFOR = 20%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.25
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	1.23	0.80	0.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	1.90	1.21	0.84	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
S8: LIL 2022, Holyrood TGS DAFOR = 20%	2.40	1.54	1.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.7
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	1.34	0.86	0.60	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.09
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	0.76	0.45	0.32	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.09

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0	0	0	0	0	0	0	0	0	0	3	26
S2: LIL 2021, Holyrood TGS DAFOR = 18%	0	0	0	0	0	0	0	0	0	0	3	26
S3: LIL 2021, Holyrood TGS DAFOR = 20%	0	0	0	0	0	0	0	0	0	0	3	26
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	65	41	29	0	0	0	0	0	0	0	0	3
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	104	62	45	0	0	0	0	0	0	0	0	5
S8: LIL 2022, Holyrood TGS DAFOR = 20%	134	83	59	0	0	0	0	0	0	0	0	7
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	70	43	31	0	0	0	0	0	0	0	0	7
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	37	21	15	0	0	0	0	0	0	0	0	7

Table 10: Monthly LOLH and EUE for 2023

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0.15	0.15	0.07	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.13
S2: LIL 2021, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	0.01	0.01	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.29
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	0.01	0.01	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.30
S8: LIL 2022, Holyrood TGS DAFOR = 20%	0.01	0.01	0.01	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.30
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	17	15	7	0	0	0	0	0	0	0	1	12
S2: LIL 2021, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	0	0	0	1	0	0	0	0	0	0	3	30
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	1	1	0	1	0	0	0	0	0	0	3	31
S8: LIL 2022, Holyrood TGS DAFOR = 20%	1	1	0	1	0	0	0	0	0	0	4	32
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 11: Monthly LOLH and EUE for 2024

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	0.17	0.15	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10
S2: LIL 2021, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S8: LIL 2022, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

EUE (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
S1: LIL 2021, Holyrood TGS DAFOR = 15%	16	14	7	0	0	0	0	0	0	0	0	8
S2: LIL 2021, Holyrood TGS DAFOR = 18%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S3: LIL 2021, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S4: LIL 2021, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S5: LIL 2021, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S6: LIL 2022, Holyrood TGS DAFOR = 15%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S7: LIL 2022, Holyrood TGS DAFOR = 18%,	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S8: LIL 2022, Holyrood TGS DAFOR = 20%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S9: LIL 2022, Holyrood TGS DAFOR = 20%, 50 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
S10: LIL 2022, Holyrood TGS DAFOR = 20%, 100 MW imports	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

7.0 System Reliability in Advance of Full In-service of the LIL

In its correspondence dated March 5, 2020 the Board requested that this report include a detailed plan and schedule describing all activities required to ensure winter 2020–2021 service reliability under the assumption that the LIL will not be available during some or all of that period, as well as similar analysis for winter 2021–2022 on the same basis.

The following sections provide information on Hydro's plan to ensure the reliable electricity supply for customers in the near-term.

7.1 Ensuring Reliability of Existing Generating Assets

Existing assets and infrastructure continue to play a key role in Hydro's supply mix through the study period. Reasonable assumptions regarding the availability and reliability of existing assets, used in the analysis which supports this report, ensures that the system is not relying on assets beyond their expected capability and that the firm capability and forced outage rates are appropriately considered.

Similar to other years, though increasingly important in consideration of the continued COVID-19 pandemic, Hydro is proactively managing its Integrated Annual Work Plan, as well as its short-term planning and work scheduling to safely execute critical maintenance and capital work activities to maintain (1) the reliable operation of electricity production and transmission assets through the 2020–2021 winter season; and (2) to undertake asset-related activities to conform to legislated requirements. Hydro continues to ensure its workforce is being deployed to complete high priority work, with controls in place to protect the safety and health of its workforce and people in the communities in which Hydro operates and travels.

Updates on completion of corrective and preventive maintenance required to ensure assets are reliable in advance of the winter operating season are provided to the Board through Hydro's Winter Readiness Planning Reports, filed in October, November and December annually. Similarly, updates on progress on capital projects in the current year are provided as part of Hydro's Capital Budget Application, filed annually in August. In light of the COVID-19 pandemic, Hydro recognizes that for the current year it may be helpful to provide an update on the progress of its winter readiness activities in advance of its first winter readiness update in October. Hydro will provide the Board with a preliminary overview of its winter readiness position through correspondence in September 2020.

7.2 Ensuring Sufficient Energy to Meet Customer Requirements

As discussed in Section 5, Hydro establishes minimum storage limits annually to ensure that it is capable of meeting customer energy requirements. In the current system, these limits represent the point at which Holyrood generation would be required to be maximized to ensure Hydro's ability to meet customer requirements in consideration of the historical dry sequence.

Hydro is establishing minimum storage limits to April 30, 2021 which assume that the LIL remains unavailable to the IIS until June 1, 2021. This will help ensure sufficient storage to reliably serve customers should the LIL continue to be delayed beyond the fall of 2020.

With the availability of thermal energy and access to external markets to provide the balance of load, the availability of energy in reservoir systems does not currently pose a risk to near-term resource adequacy. Further, while it has been assumed for the purpose of establishing these targets that the LIL will not be available in advance of June 2021, deliveries over the LIL would increase the amount of economic energy available to the IIS, which would reduce the amount of higher cost energy required to maintain sufficient energy in storage.

In addition, regular assessments of storage at a reservoir level basis will continue to be completed to ensure that each hydraulic generating unit remains capable of producing at full rated output through the winter period.

7.3 Extension of Holyrood TGS as a generating facility and proposed extension of Hardwoods and Stephenville GTs

As discussed in Section 3.3.1, Hydro has always intended to maintain up to a two-year period of standby operation of the Holyrood TGS during early operation of the Muskrat Falls Project Assets. In correspondence dated February 14, 2020, Hydro advised the Board of an extension to the operations of Holyrood TGS as a generating facility to March 31, 2022. The decision to extend operations of Holyrood TGS at that time was made to help ensure Hydro's ability to reliably supply customers during the winter of 2020–2021.

In the 2019 Update, Hydro advised that continued operation of the Holyrood TGS as a generating facility past March 31, 2021 would require additional capital investment and execution of operation and maintenance activities. Hydro received approval for capital projects necessary to be completed in 2020 for the continued operation of the Holyrood TGS on May 11, 2020.[25]

As described in the 2019 Update, Hydro is prepared to extend operation of the Holyrood TGS to March 31, 2023, if warranted based on further delays in the reliable supply of energy from the Muskrat Falls project. Hydro is providing this analysis to further inform the discussion regarding the provision of reliable supply for customers. Similar to the processes undertaken for the extension of operation as a generating facility to March 31, 2022, should additional decisions be made regarding the extension of Holyrood TGS as a generating facility, Hydro will notify the Board of its decision and seek appropriate Board approval for any other capital expenditures, as required.

As discussed in section 3.3.2, given continued uncertainty regarding the reliable in-service of the LIL, Hydro proposes to retain the Hardwoods GT in service until the LIL is proven reliable. To ensure an appropriate balance of cost and reliability in this matter, Hydro will undertake necessary preventive and corrective maintenance work to ensure Hardwoods GT remains available to the IIS; however, Hydro will re-evaluate the decision to retain all or portions of the assets in service should extensive maintenance or incremental capital expenditures are required to facilitate this life extension.

As discussed in Section 3.3.2, the Stephenville GT is required to remain in service until the in-service of a power transformer at Bottom Brook Terminal Station. As such, it will continue to be available through the next two winter seasons.

7.4 Imports over the Maritime Link

Since the in-service of the Maritime Link, Hydro has been successful in making economic purchases to economically offset the requirement to produce additional thermal energy. From September 2019 through March 2020, 311 GWh was imported over the Maritime Link, offsetting higher cost thermal generation. While all of the market purchases to date have been made on an economic basis, these purchases have also provided system reliability benefits by reducing the requirement to operate Holyrood TGS and standby generation.

For the period from September 2019 through the end of March 2020, Hydro imported power through a combination of monthly agreements, day-ahead commitments, and real-time transactions. During this period, purchased energy was successfully delivered in more than 95% of scheduled hours.

[25] Board Order No. P.U. 14(2020).

As outlined in Section 6, import scenarios are contemplated as sensitivities to cases considered in this report. Hydro modelled firm imports of 50 MW and 100 MW from December to March in winters before the LIL is placed in service, with an associated FOR intended to serve as proxy for anticipated potential interruptions to the import. Since the availability of these contracts requires a counterparty to provide firm capacity, there is no guarantee that these contracts would be available. The analysis demonstrates the effect on the system if the capacity was available in the requested amounts.

7.5 Capacity Assistance

Hydro currently has an agreement with CBPP for capacity assistance. The current agreement expires on the earlier of April 30, 2022 or the commissioning of the Muskrat Falls Generating Plant, ensuring the availability of this agreement to increase system reliability should the LIL be unavailable in either of the 2020–2021 or 2021–2022 winter operating seasons.

Since 2014, Hydro has engaged Vale through various agreements to provide capacity assistance from its diesel generators. The most recent agreement provided capacity assistance through the 2019–2020 winter operating season and expired on March 31, 2020. Should the LIL be unavailable in either of the 2020–2021 or 2021–2022 winter operating seasons, Hydro would engage Vale with the intent to undertake an agreement for capacity assistance for that winter. Hydro will decide by October 15, 2020 if such an agreement is required for the 2020–2021 winter operating season and advise the Board at that time.

7.6 Emergency Response Plan for the LIL

Nalcor Energy Power Supply ("Power Supply") has established an Emergency Response Plan ("ERP") for the overhead transmission lines to be in operation in advance of winter 2020–2021. The purpose of this ERP document is to supplement the information provided in the Phase II Overhead Transmission Lines ERP, which outlined Nalcor Energy's progress and plans to date for all emergency restoration activities.[26] This ERP includes the planned operational response in place for winter 2020–2021. It includes information related to personnel, equipment, material locations, protocols, and logistical plans to be followed in the event of a line failure during this time. The ERP document is provided in Attachment 1.

[26] Filed with the Board on December 19, 2019.

8.0 Conclusion

Hydro closely monitors its supply-related assets to ensure its ability to provide reliable service to customers. As previously identified by both Hydro and The Liberty Consulting Group, the availability of power over the LIL remains essential to system reliability in the near-term. Hydro is working closely with Nalcor's Power Supply leadership to monitor and mitigate the risks associated with the timing of the in-service of the LIL to supply off-island capacity and energy to the Island Interconnected System. Hydro is also working to complete critical maintenance activities and other high priority work to ensure the reliability of its existing assets and infrastructure in the near-term.

To help ensure reliable service for customers in advance of the in-service of the LIL, Hydro has committed to maintaining Holyrood TGS as a generating facility until March 31, 2022. Hydro will inform the Board of any changes to this timeframe as we continue to monitor LIL progress and schedules. Hydro also proposes to extend operation of the Hardwoods GT and retire this asset at the same time as the Holyrood TGS.

There is potential to mitigate identified resource shortfalls by entering into contracts for firm capacity over the Maritime Link and renewing capacity assistance agreements, as required. Following the full in-service of the Muskrat Falls project assets and the retirement of Holyrood TGS, small values of LOLH and EUE continue to be observed in winter months increasing with retirements and increasing system load; however, values are materially reduced from those observed prior to the in-service of the Muskrat Falls project assets.

Attachment 1

Labrador-Island Link Overhead Transmission Line Emergency Response Plan – Winter 2020-2021

Nalcor Energy - Power Supply

Labrador-Island Link Overhead Transmission Line

Emergency Response Plan – Winter 2020-2021

Comments:	Total # of Pages: (Including cover and appendices): 22

Status / Revision	Date	Reason for Issue	Prepared by Ryan Elliott	Chad Wiseman Director, Transmission	Bob Woodman Team Lead Work Execution Lines	John Walsh Manager Transmission and Civil Engineering

L3501/2 Overhead Transmission Line Emergency Response Plan

Contents

L3501/2 Overhead Transmission Line Emergency Response Plan

1. Purpose

The purpose of this Emergency Response Plan ("ERP") document is to supplement the information provided in the Phase II Overhead Transmission Lines ERP, which outlined Nalcor Energy – Power Supply's ("Power Supply") progress and plans to date for all emergency restoration activities. This ERP outlines the planned operational response in place for winter 2020-2021. It provides information related to personnel, equipment, material locations, protocols, and logistical plans to be followed in the event of a line failure during this time.

2. Background

The Labrador-Island Link is a 900 MW, +/- 350 kV HVdc transmission system between Muskrat Falls in Labrador and Soldiers Pond on the island portion of the province. The Labrador-Island Link overhead HVdc transmission line traverses approximately 1,100 km from Muskrat Falls to Soldiers Pond. The elevation of the Labrador-Island Link varies from 0 m to approximately 630 m above sea level.

The Labrador section of the Labrador-Island Link includes two electrode conductors from the Muskrat Falls converter station to the grounding station in southern Labrador. Most of the electrode line in Labrador (370 km) is on the ±350 kV HVdc steel transmission towers above the pole conductors and below the tower's single optical ground wire. The remaining 14 km of the electrode line in Labrador is supported by wood poles.

Figure 1: Labrador-Island Link

3. Scope

This ERP has been prepared in conjunction with other emergency response and restoration plans specific to Nalcor Energy ("Nalcor"), Power Supply, and Newfoundland and Labrador Hydro ("Hydro"). It is applicable to line failures on:

- L3501/2 between Muskrat Falls and Forteau Point;
- L3501/2 between Shoal Cove and Soldiers Pond;
- The electrode line between Soldier's Pond and Dowden's Point (EL 3/4); and
- The electrode line between Muskrat Falls and L'Anse Au Diable (EL 1/2).

Given the focus of this document on emergency response and restoration plans specific to the Overhead Transmission Line, the converter stations, transition compounds and communication repeater sites are not included in the scope of this ERP.

This ERP provides guidance and procedures to ensure Soldiers Pond Emergency Operations Centre and the Nalcor Corporate Emergency Operations Centre are prepared to assemble to provide emergency support, if required, during the winter 2020-2021 operating period.

4. Roles and Responsibilities

The role and responsibilities of the Soldier's Pond Emergency Operations Centre are summarized in Appendix A. Individual roles and responsibilities are summarized in Appendix B.

5. Emergency Response Protocol

Upon receipt of notification of a line fault alarm at the Soldiers Pond Converter Station, technical operations will first identify the details of the fault. The approximate location[1] of the line fault will be identified using line fault location equipment that is located at both converter stations and both transition compounds. Line fault locating devices are accessible by technical operators at the Soldiers Pond and Muskrat Falls Converter Stations who will provide the initial assessment to direct crews to the location of the line fault. In the event of a sustained fault, maps and GPS tools would also be used to determine the physical location of the fault. Based on the location of the fault, information related to the environment, topography, road access, helicopter landing zones, external emergency service access, etc. is used to determine the appropriate method to access the line for inspection.

[1] Line fault detectors are designed to detect a fault within several kilometers of the affected tower(s).

Once the location of the fault has been determined, an initial assessment team will be dispatched to survey the area of the line. Initial assessment teams are equipped with cellular and satellite phones. Power Supply has two line crews[2] that provide routine maintenance on the Labrador-Island Link Overhead Transmission Line. In the event of a fault, the line crew responsible for the area where the fault occurs will execute the initial response, or Power Supply can call on Hydro to deploy its personnel to execute the initial response.[3]

The purpose of the initial survey is to gather information about the failure including potential equipment damage, the terrain in the area of the fault, condition of access roads, etc. This information will be relayed to the engineering team, who are responsible for the development of the restoration solution. The initial assessment team will remain on-site or in the general area until the draft design is prepared so they can gather additional information required by the engineering team, as required.

For expediency purposes, the initial assessment team would travel to site and survey by helicopter; however, storm conditions are typically the cause of failures, so alternate modes of travel (trucks, all-terrain vehicles, snowmobiles, etc.) may be required. While the initial assessment team is travelling to the fault location, the Soldier's Pond Emergency Operations Centre will provide early notifications to internal and external personnel who may be required to participate in a restoration effort.

If required based on the initial assessment of the failure, additional line crews will be dispatched to provide assistance. Power Supply maintains internal contact information, as well as that of contractors and mutual aid partners to provide additional resources as required based on the specific failure situation. Appendices C and D provide the relevant contact information.

The following example provides the sequence of events that would occur in the event of fault detection on both poles (i.e., a bi-pole event):

1) Notification of fault
    a. The Soldiers Pond Station operator would receive an alarm indicating detection of a bi-pole fault on the Labrador-Island Link and will notify the ECC. The Soldiers Pond or Muskrat Falls Converter operator, depending on the line section impacted, would refer

[2] One crew is located in Labrador, the other is located on the island.
[3] Power Supply has agreements with Hydro for the provision of maintenance services, which can be used to dispatch personnel and equipment to perform the initial assessment in the event that Hydro's personnel are not attending to higher priority work on Hydro's assets and can arrive at the fault location before Power Supply's personnel.

to the line fault locator to identify the location of the fault, and call the Power Supply on-call to report the trip.

2) Communication of fault to required parties
   a. The Power Supply on-call would activate the SOP Emergency Operations Centre.
   b. The Power Supply on-call would notify the appropriate lines supervisor of the fault, who would notify crew members and dispatch them to the fault location for an initial assessment.
   c. The Power Supply on-call would contact P&C[4] Engineering to review Human Machine Interface ("HMI") alarms / events and Digital Fault Recorder ("DFR") traces to confirm correct protection operated.
   d. The Soldier's Pond Incident Commander would contact the Energy Control Centre to notify the Corporate Emergency Operations Centre staff on-call to initiate the Corporate Emergency Operations Centre protocols.
3) Identification of fault location and conditions
   a. The Soldier's Pond Emergency Operations Centre team would use the fault location information provided by the technical operator to determine the location of the fault and weather and road conditions. They would determine the appropriate line crew to perform the initial assessment and the most appropriate method of travel to the fault location.
4) Initial assessment
   a. The initial assessment team will collect their initial assessment tool kit and begin to travel to site.
   b. While the initial assessment team is travelling, the transmission engineering group will be provided with the available information and, if possible, a timeframe related to the initial assessment team's report. Based on the severity of the situation, other restoration resources will be notified and deployed as appropriate information is available.
   c. While on site, the initial assessment team would take pictures, record tower numbers, note terrain condition, access road condition, etc. and report back to the Soldier's Pond Emergency Operations Centre and the Transmission Engineering group. The team would

[4] Protection and Controls ("P&C")

stay on site until the engineering group had sufficient information for the restoration design.

5) Proposed restoration design
    a. The engineering group would propose a design to the Soldier’s Pond Emergency Operations Centre with the focus on restoring to mono-pole operation as quickly as possible, and the Soldier’s Pond Emergency Operations Centre would shift focus from emergency response to emergency restoration.

6. Emergency Restoration Protocol

Once the extent of the damage has been determined, a restoration plan will be prepared and restoration resources will be dispatched to implement the emergency restoration plan. The restoration response is partially informed by the classification of the fault incident, which often cannot be confirmed until personnel arrive on site to assess the situation and quantify the impact.

6.1 Incident Classification

In 2017, Power Supply engaged EFLA Engineering Consultants Inc. (“EFLA”) to assess common practices with respect to overhead lines emergency response planning. As part of its engagement, EFLA performed an analysis of various restoration aspects for the Labrador-Island Link Overhead Transmission Line. EFLA’s report classifies production failure incidents based on six levels, from 0-5 with zero representing no immediate incident, to five representing a catastrophic incident.

Power Supply has a previously-established system for classifying general incidents based on a three-tier system, which then informs the emergency response criteria and communication protocol required. The EFLA production incident classification system is used to determine which of the three levels of Power Supply’s emergency response is appropriate for the incident.

Table 1 provides examples of the types of failures that would fall into each of the six levels, and the corresponding incident response classification under Power Supply’s system.

L3501/2 Overhead Transmission Line Emergency Response Plan

Table 1: Failure Description Using Incident Levels Classification

Incident Level	Short Description	Description	Action Needed	Example of Failure	Power Supply Incident Response Classification
0	None	Alert status, potential failure/outage	Emergency preparation	No failure	N/A
1	Minor	Localized failure, limited complications	Emergency preparation and site visit	Lightning, short term internal- or external clearance may last few hours, e.g. outage due to galloping or wind	N/A
2	Moderate	Localized failure, slight complications	Site visit and corrective action with limited equipment	Insulator, hardware, conductor damage, cross arm damage, guy failure with foundation damage	Incident Level 1
3	Major	Localized failure, moderate complications	Site visit and corrective action with some material and equipment	Tower failure	Incident Level 2
4	Severe	Multiple failure	Site visit and corrective action with material and equipment, site camp establishment	Multiple tower failures, same area, or failure of tension tower	Incident Level 3
5	Catastrophic	Multiple failure, considerable complications	Site visit and corrective action with significant material and equipment, several site camps, large logistical and materials planning effort	Dispersed multiple tower failures, cascade failure	Incident Level 3

Based on the emergency response requirements, the Soldiers Pond Emergency Operations Centre will initiate the Corporate Emergency Operations Centre support, if required. Primary emergency operational support will be provided by Soldier's Pond Emergency Operations Centre with additional supports provided by the Corporate Emergency Operations Centre.

6.1.1 Incident Level 1

A fault would be classified as an incident level one if it met the criteria of an EFLA production incident level 2. Such a fault would be considered a minor production issue that has not resulted in a sustained line power flow interruption. This could potentially be a mono-pole failure. Table 2 provides a description of a level one incident, as well as the associated emergency response criteria and mobilization required.

Table 2: Incident Level 1 Emergency Response Summary

<table>
<tr><th colspan="2">Soldiers Pond Emergency Operations Centre Team
Mobilized at Discretion of Incident Commander</th></tr>
<tr><td colspan="2">Description
• Minor local emergency confirmed.
• Minor operational issue or risk identified.
• Impact is confined to one area of the line.
• No immediate hazard to other employees, the public, or the environment.
• No uncontrolled escalation expected.
• Emergency can be managed at site.</td></tr>
<tr><td colspan="2">Emergency Response Criteria
• Personal Injury or Illness: Minor injury or illness requiring external medical intervention or notification.
• Fire: Contained and controllable fire.
• Operational Incident: Production Incident Level 2 - a minor production issue that has not resulted in any sustained power flow interruption; potentially a mono-pole failure.
• Explosion: An explosion has resulted in minimal on-site damage. Poses no threat.
• Bomb or Terrorist Threat: A bomb or terrorist threat has been received, but no further evidence of potential escalation is involved.</td></tr>
<tr><td colspan="2">Initial Notification or Mobilization</td></tr>
<tr><td>Field</td><td>Soldiers Pond / St John’s</td></tr>
<tr><td>• Operations response dispatched.
• Local authorities related to the location are notified, if required.
• Contractor personnel are notified, if required.</td><td>• Power Supply on-call is notified
• Corporate Emergency Operations Centre is notified on the discretion of the incident commander
• Soldier’s Pond Emergency Operations Centre team on stand-by in case of escalation</td></tr>
</table>

6.2.2 Incident Level 2

A fault would be classified as an incident level two if it met the criteria of an EFLA production incident level 3[5]. It is characterized by a production issue that has resulted in a sustained line power flow interruption, as well as equipment damage or a failure with the potential for further damage to a localized area of the line. This could potentially be a mono- or bi-pole failure. Table 3 provides a description of a level two incident, as well as the associated emergency response criteria and mobilization required.

Table 2: Incident Level 2 Emergency Response Summary

Soldiers Pond Emergency Operations Team Mobilized and Corporate Emergency Operations Centre on Stand-by
Description
• Minor local emergency confirmed. • Incident has resulted in a power outage. • Impact extends to a broader area of the line. • Has potential to result in serious impact to an area of the line. • Some hazards to public or the environment may exist. • Emergency can be handled locally with external support.
Emergency Response Criteria
• **Personal Injury or Illness:** Major disabling injury or illness requiring external medical intervention. • **Fire:** Worksite has experienced a fire, leading to major equipment damage with significant risk to an area of the line. • **Operational Incident:** Production Incident Level 3 - a production issue has resulted in a sustained power flow interruption. Equipment damage or failure occurred with potential for further damage to a localized area of the line. Could be a mono-pole or a bi-pole failure. • **Explosion:** An explosion has resulted in significant damage to equipment and an area of the line. • **Toxic Materials:** An unexpected release of toxic materials has been confirmed with the potential to spread. • **Bomb or Terrorist Threat:** A bomb was detonated or terrorist action has occurred, but no further evidence of potential escalation is involved.

[5] Until the initial assessment team has been at the site of the failure, the incident level will not be known. These classifications will be applied after the initial site assessment has been made.

L3501/2 Overhead Transmission Line Emergency Response Plan

Initial Notification or Mobilization	
Field	**Soldiers Pond / St John's**
• Operations response dispatched • The on-scene-commander shall take directions from Power Supply on-call • Power Supply on-call will act as incident commander and report to the SOP EOC until the SOP EOC IC is in place. • External agencies shall be dispatched • Contractor personnel are notified if needed	• Soldier's Pond Emergency Operations Centre activated • Corporate Emergency Operations Centre Executive Member on-call notified by the incident commander at Soldier's Pond Emergency Operations Centre • Corporate Emergency Operations Centre team on stand-by in case of escalation

6.2.3 Incident Level 3

A fault would be classified as an incident level three if it met the criteria of an EFLA production incident level 4 or 5. It is characterized by a production issue that has resulted in a long-term power flow interuption resulting from extensive equipment damage or a failure to multiple towers at one or more areas of the line. This would be a bi-pole failure. Table 4 provides a description of a level three incident, as well as the associated emergency response criteria and mobilization required.

Table 4: Incident Level 3 Emergency Response Summary

Full Mobilization of Soldiers Pond Emergency Operations Centre and Corporate Emergency Operations Centre Team
Description
Resultant from one or more of the following: • Catastrophic emergency confirmed. • Incident has resulted in a long term power flow interruption. • Site operating control and integrity has been lost. • Serious impacts extend outside the area of the line. • Uncontrolled escalation of the emergency. • Definite and serious hazards to public and/or environment exists. • Emergency cannot be efficiently managed at the site level.
Emergency Response Criteria
• **Confirmed Personnel Loss** • **Fire:** A major uncontrolled fire (ex. forest fire) causing threat to the integrity and safety of the line, personnel or the public.

<table>
<tr><th colspan="2">L3501/2 Overhead Transmission Line Emergency Response Plan</th></tr>
<tr><td colspan="2">Operational Incident: Production Incident Level 4 or 5. Long term power flow interruption resultant from extensive equipment damage / failure to multiple towers at one or more areas of the line.
Major Spill: A major spill continues with the source not identified. Extensive mobilization of containment and recovery equipment is required.
Bomb or Terrorist Threat: A bomb has been located or detonated or terrorist action has occurred resulting in damage and a threat to the integrity of the line, personnel and/or the general public.</td></tr>
<tr><td colspan="2">Initial Notification or Mobilization</td></tr>
<tr><td>Field</td><td>Soldiers Pond / St John’s</td></tr>
<tr><td>Operations response dispatched
The on-scene-commander shall take directions from Power Supply on-call
Power Supply On-call will act as incident commander and report to the Soldier’s Pond Emergency Operations Centre until the Soldier’s Pond Emergency Operations Centre incident commander is in place
External agencies shall be dispatched</td><td>Soldier’s Pond Emergency Operations Centre Activated
Corporate Emergency Operations Centre manages the restoration effort with support from Soldier’s Pond Emergency Operations Centre as well as external local, provincial and national resources.
Corporate Emergency Operations Centre members are mobilized.</td></tr>
</table>

7. Emergency Restoration Activity

As the magnitude of a failure, the location, and the conditions at the time of the failure can vary materially, it is not possible to provide specific emergency restoration activities in this document. However, the typical steps to restore power to at least one of the HVdc lines in operation as quickly as possible are demonstrated in Figure 2.

L3501/2 Overhead Transmission Line Emergency Response Plan

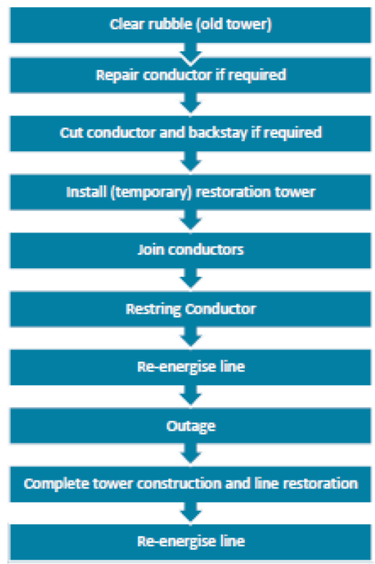

Figure 2: Emergency Restoration Steps

In a conventional line restoration method, transmission line towers are restored using the same right of way. Restoration may also be achieved by bypassing the damaged portion of the transmission line using temporary structures. In this scenario, the damaged portion of the transmission line is bypassed on either side of the existing right of way on temporary structures. The decision as to which method to use is determined on a case-by-case basis.

8. Emergency Restoration Resources

There are numerous resources available to perform restoration response activities for the Labrador-Island Link during the winter 2020-2021. This includes internal personnel, mutual aid agreements with other utilities, contracts with third parties who typically perform transmission line construction work, as well as equipment and materials.

8.1 Personnel

8.1.1 Internal Personnel

Power Supply has two line crews, each consisting of a supervisor and four line workers. One crew is based in Labrador and the other crew is based on the island. The primary function of the crews is to perform preventative maintenance and minor corrective maintenance activities within each region. Both crews work together for larger jobs and emergency restoration as required.

In emergency restoration situations, the Power Supply line crews will be supplemented with other Power Supply personnel, including engineering, general maintenance workers, safety and environment representatives, electrical and mechanical maintenance personnel and the vegetation coordinator for various support aspects of the restoration effort as the need is determined by the incident commander.

8.1.2 Mutual Aid Agreements

Agreements are in place with Hydro and Nalcor Energy – Churchill Falls that facilitate the provision of personnel and equipment as required for maintenance activities. This provides a larger labour and equipment pool for emergency restoration activities.

8.1.3 Third-Party Contracts

Power Supply has a three-year contract with two local line contractor companies to provide line maintenance and construction support as required, including in emergency situations. This contract provides access to additional line workers, and equipment that is typical to line construction work. Power Supply maintains a list of other national contractors that can be contacted and an emergency contract entered into for larger restoration efforts where local resources are not sufficient. Please refer to Appendix D.

8.2 Equipment

Lines crews are provided with the equipment required for regular maintenance and repairs. Additionally, equipment specific to the Labrador-Island Link that is not readily available from third party contractors has been procured.[6] Although the delivery of some equipment has been impacted by the COVID-19 pandemic, arrival is still anticipated in advance of the 2020-21 winter operating season. In the event of more severe delays in which outstanding items are not received in advance of the winter operating season, restoration efforts will be performed with available material and equipment, though response time may be impacted. A list of equipment available for use in emergency response and restoration efforts is provided in Appendix E.

[6] Power Supply primarily owns equipment that is used for regular maintenance purposes; equipment that is used for extraordinary maintenance and restoration is readily available and owned by contractors with which Power Supply has existing master service agreements. This includes equipment such as excavators, dump trucks, helicopters, 75' tracked cranes, tractor trailers and flat bed decks for transporting materials.

Power Supply is in the process of purchasing additional equipment which is expected to be available for emergency restoration activities during the winter 2020-2021 operating period, as follows.

- Two one-ton service body trucks (one for each of the two regions).
- An enclosed ATV that is capable of transporting multiple people, tools, site supplies and small materials during all seasons and under all access conditions.
- Two 18-ton tracked cranes with a 160’ boom. Power Supply is purchasing one of the cranes and will station it in Labrador and Hydro is purchasing the other one and stationing it on the island.[7] Power Supply and Hydro will provide access as required to both companies to use both cranes.
- Live line tools to facilitate the correction of deficiencies on the line while transferring power, therefore reducing vulnerability due to severe weather.
- An insulated boom is being purchased to increase the capability for live line work.

8.3 Locations of Materials

Materials available for emergency restoration activities in winter 2020-2021 are stored at Muskrat Falls and in Argentia. Additional storage locations are being explored on the Northern Peninsula, in Central Newfoundland and in Southern Labrador to provide faster access to short-term emergency restoration solutions (e.g., wood pole by-pass solution materials). Further to these storage locations, temporary equipment laydown and storage locations are being considered inside the Long Range Mountains Alpine zone. Potential sites are expected to be identified in 2020 for development in 2021. A line crew camp will be constructed in this remote area of central Labrador prior to the 2021-2022 winter operating season.

Power Supply has adequate maintenance spares to replace one full section of the transmission line between two anti-cascade structures. The line design consists of no more than 22 structures between anti-cascade towers. Due to diverse meteorological conditions encountered across the 350 kV HVdc transmission line, there are 11 different types of towers. This necessitates a larger quantity of spares, mainly tower bodies and extensions. To determine the quantity of tower bodies and extensions required, an analysis was performed which examined the quantity and type (including extensions) of structures used throughout the HVdc line. This ensures sufficient parts are available to quickly perform the required repairs in the event of a cascade failure on any line section. Available maintenance spares include:

[7] Approved in Board Order No. 43(2017).

- all main tower bodies and extensions;
- hardware assemblies (tangent suspension, dead-end, jumper, and optical ground wire);
- cables (conductor, and optical ground wire); and
- insulators.

Although it was determined that acquisition of foundation spares would not be required due to the probability that foundations could be re-used in a tower failure, select "ground level" foundation construction surplus has been retained for added security.

In addition, spare wooden pole and associated hardware for two km of transmission lines have been procured and are stored for use as bypasses. This quantity will be refined as part of a continual evaluation of emergency restoration activities and requirements.

As part of capital spare purchases in 2020, Power Supply is in the process of acquiring additional material to enable timely restoration in certain failure scenarios. Composite insulators have been purchased and are expected to be delivered in time to use them for ERP exercises prior to the 2020-2021 winter operating season. Materials for the emergency restoration structures, swivel base adapters and modification to existing tower pieces are in various stages of the design and fabrication phases. Due to the ongoing COVID-19 pandemic, the delivery of this equipment prior to the start of the 2020-2021 winter operating season is not certain at this time. In the event of delays in which outstanding items are not received in advance of the winter operating season, restoration efforts will be performed with available material and equipment, though response time may be impacted.

9. Reference Documents

- OHTL Emergency Restoration Plan
- Corporate Emergency Response Plan (CERP)

10. Emergency Call Out Tree

Appendix F provides a call out sequence for emergencies requiring support from external agencies and first responders such as fire, medical, rescue or environmental release and for production failures.

Appendix A: Soldier's Pond Emergency Operations Centre Roles & Responsibilities

Soldier's Pond Emergency Operations Centre
Roles and Responsibilities
Maintain a fully functional Emergency Operations Centre to provide appropriate response expertise and resources to the Site Emergency Response, as required.
Communicate with external agencies, as required.
Determine the need to notify the Corporate Emergency Operations Centre through ECC as per determined incident level and circumstances pertaining to the incident. **Level 1:** **Minor Local Emergency** • Local Site Emergency Response • Production Incident Level 2 **Level 2:** **Major Local Emergency** • Advanced Emergency Response involving external agencies • Production Incident Level 3 **Level 3:** **Catastrophic Emergency** • Crisis Management • Production Incident Level 4 or 5
Ensure Corporate Emergency Operations Centre are informed and periodically updated as outlined in the Emergency Response Plan.
Ensure Regulatory Contacts are carried out as appropriate and as required in a timely manner and any communications are fully documented.
Coordinate with Support Services (as required)
Project Communications

Appendix B: Individual Roles & Responsibilities

Overhead Transmission Line
Roles and Responsibilities
Soldiers Pond On Call: • Provide appropriate response expertise and resources to the Site Emergency Response, as required. • Activate the Soldier's Pond Emergency Operations Centre, as required. • Ensure contact has been made with responding agencies (911), and the Lines Supervisor.
Soldier Pond Incident Commander: • Determine the level of the incident. • Provide leadership and guidance while interacting with external agencies and first responders. • Activate Soldier's Pond Emergency Operations Centre, if required. • Notify Executive on Call, if required.
On-scene Commander: • Respond to the incident scene. • Contact responding agencies (911). • Work with Soldier's Pond Emergency Operations Centre to mitigate any problems or concerns. • Oversee execution of the restoration effort.
Corporate Emergency Operations Centre: • Dependant on Incident Level and circumstances.
Soldiers Pond Converter Station Operator: • Receive initial reports of incident from the Line Fault Locator computer • Communicate with Power Supply on call, dispatch and first responders, as required. • Act as the dispatch center for working alone and lightning notification.
First Responders, Fire & Medical: • Respond to any emergency if required. • Take direction from Power Supply on-scene commander, as required.

Appendix C: Internal Contact Numbers

Name	Number	Alt. Number	Position
Soldiers Pond on Call - 24/7	XXX-XXXX		
Soldiers Pond CS Control Room	XXX-XXXX		
Energy Control Center (ECC) 24/7	XXX-XXXX	XXX-XXXX	
MF Line Truck 1	XXX-XXXX	XXX-XXXX	
MF Line Truck 2	XXX-XXXX	XXX-XXXX	
SOP Line Truck 1	XXX-XXXX	XXX-XXXX	
SOP Line Truck 2	XXX-XXXX	XXX-XXXX	
Bob Woodman	XXX-XXXX	XXX-XXXX	Team Lead - Work Execution
Derek Michelin	XXX-XXXX		Line Supervisor - Lab
Patrick Keough	XXX-XXXX	XXX-XXXX	Line Supervisor - Nfld
Chad Wiseman	XXX-XXXX	XXX-XXXX	Director, Transmission
Perry Taylor	XXX-XXXX	XXX-XXXX	Regional Manager ,SOP
Mike Thompson	XXX-XXXX	XXX-XXXX	Technical Supervisor - Operations
Mark White	XXX-XXXX	XXX-XXXX	Technical Supervisor - Operations
Joe Lake	XXX-XXXX		Safety Advisor, SOP
Ryan Elliott	XXX-XXXX		Senior Safety Supervisor
Vacant	---		Safety Advisor, MF
Leah Fudge	XXX-XXXX	XXX-XXXX	Environmental Coordinator
Marion Organ	XXX-XXXX	XXX-XXXX	Manager Environment & Sustainability
John Walsh	XXX-XXXX	XXX-XXXX	Eng Mgr - Transmission
Maria Veitch	XXX-XXXX	XXX-XXXX	Transmission Engineer
Justin Baikie	XXX-XXXX	XXX-XXXX	Eng Mgr - HVdc
James Nugent	XXX-XXXX	XXX-XXXX	HVdc Engineer
Nicholas Keough	XXX-XXXX	XXX-XXXX	HVdc Engineer
Tom Foss	XXX-XXXX	XXX-XXXX	Hydro Helicopter contact
Andrea Pelletier	XXX-XXXX		CF Chief Helicopter Pilot
Dave Hussey	XXX-XXXX	XXX-XXXX	CF Airport Manager

Appendix D: External Contact Numbers

Company / Agency	Number	Alt. Number	Comments
Provincial Emergency	911		Island-wide Dispatch
Ambulance / Hospital / RMP	911		Emergency Only
Oil Spill Response - Coast Guard 24/7	XXX-XXXX		St. John's
Forestry	XXX-XXXX		To report a wild fire
Wildlife	XXX-XXXX		Normal business hours
Air Ambulance	XXX-XXXX		
NLH OHS (Service NL)	XXX-XXXX		Serious Accident Reports
Canadian Coast Guard	XXX-XXXX		
CANUTEC	XXX-XXXX		
Provincial Health Line	XXX-XXXX		
Poison Control	XXX-XXXX		
Locke's Electrical – Kevin Gosse	XXX-XXXX		Local Line Work contractor
Curtis Powerworks	XXX-XXXX		Local Line Work contractor
Dept. Highways	XXX-XXXX		Highway Condition / Snow Clearing
Allteck - dispatch	XXX-XXXX	XXX-XXXX	Line Work Contractor
Valard – David Togerson	XXX-XXXX		Line Work Contractor
Canadian Helicopter - Dispatch	XXX-XXXX	XXX-XXXX	Contract Helicopter Service provider
Universal Helicopter – Goose Bay (Dispatch)	XXX-XXXX		Alternate Helicopter Service provider
Universal Helicopter – Pasadena	XXX-XXXX		Alternate Helicopter Service provider
Universal Helicopter – Gander	XXX-XXXX		Alternate Helicopter Service provider
Universal Helicopter – St John's	XXX-XXXX		Alternate Helicopter Service provider
Newfoundland Helicopter - Dispatch	XXX-XXXX	XXX-XXXX	Alternate Helicopter Service provider
Nexans (Norway) - Peggy Aasheim	XXX-XXXX	XXX-XXXX	SOBI cable repair Peggy.aasheim@nexans.com www.nexans.no

Appendix E: Equipment Available for Emergency Restoration Activities

- Pick-up trucks
- Snowmobiles and sleighs
- All Terrain Vehicles (6X6 and Argo with tracks)
- Open snowmobile trailers
- Enclosed snowmobile / ATV trailers
- Satellite communication equipment
    - Satellite phones and InReach devices (currently used)
    - Power Supply has access to a satellite data hub owned by the construction group in Muskrat Falls, which will be transferred to Power Supply after construction is complete.
    - A satellite data hub unit will be purchased for the island prior to the 2020/21 winter operating season.
- GPS equipment with maps containing tower and access road information
- Emergency shelters
    - Prospector tent complete with wood stove
- Standard climbing and fall protection equipment for line workers
- Mini-excavator which can be transported by helicopter for initial site snow clearing and preparation
- Hand tools used to construct steel towers and temporary wood structures
    - Tool list was used and deemed effective during restoration exercises for wood pole and tower assemble exercises in 2018 and 2019
- Hoists, handlines and rigging equipment
- Tension meter for guy wires
- Conductor tensioner for stringing conductor
- Compression tools for joining conductors and guy wires
    - Required compression dies have been purchased and are expected to be available prior to the winter 2020-2021 operating season.

L3501/2 Overhead Transmission Line Emergency Response Plan

Appendix F: Labrador-Island Link Emergency Response Call Out

nalcor energy POWER SUPPLY

LIL OHTL EMERGENCY RESPONSE CALL OUT
NOTIFICATION AND ROLES AND RESPONSIBILITIES

External Emergency Support
Fire Department, Ambulance, Police
Call 911

Corporate Emergency Operations Centre (CEOC)
In order to notify the executive on call you must call ECC.
ECC 24/7 Number
XXX-XXX-XXXX
XXX-XXX-XXXX

Power Supply On-call Supervisor
Call in the event of an emergency 24/7
XXX-XXX-XXX

SOP Emergency Operations Centre Members

Director, Transmission		
Wiseman, Chad	XXX-XXXX(w)	XXX-XXXX (c)
Safety Manager		
Tilley, Steve	XXX-XXXX(w)	XXX-XXXX (c)
Safety Supervisor		
Lake, Joe	XXX-XXXX(w)	XXX-XXXX (c)
HSE Advisor– Power Supply		
Elliott, Ryan	XXX-XXXX(w)	XXX-XXXX (c)
Work Execution Team Lead – Lines		
Woodman, Bob	XXX-XXXX(w)	XXX-XXXX (c)
Work Execution & Operations Manager		
Oliver, Evan	XXX-XXXX(w)	XXX-XXXX (c)
Supervisors		
Lines Supervisor – Island		
Keough, Patrick	XXX-XXXX(w)	XXX-XXXX (c)
Technical Supervisor – Operations		
White, Mark	XXX-XXXX(w)	XXX-XXXX (c)
Technical Supervisor – Operations		
Thompson, Mike	XXX-XXXX(w)	XXX-XXXX (c)
Lines Supervisor - Labrador		
Michelin, Derek	XXX-XXXX (c)	
Engineering Manager – AC Terminals and HVDC Spec		
Baikie, Justin	XXX-XXXX(w)	XXX-XXXX (c)
Engineering Manager – Transmission & Civil		
Walsh, John	XXX-XXXX(w)	XXX-XXXX (c)

OBSERVER:
- Call 911 if necessary (provide details of location)
- Contact your immediate supervisor during regular hours
- Contact Power Supply On Call supervisor after hours
- Contact External Agency if necessary

↓

IMMEDIATE SUPERVISOR/ON-CALL SUPERVISOR:
- Contact External Agency If Necessary -911
- Contact member of the SOP EOC
- If no response from SOP EOC then make a decision to call CERP if necessary
- Access the scene & work to make the area safe
- Ensure OSC is identified and in place

↓

SOP EOC MEMBER:
- Contact external agencies as needed – 911 after confirming with OSC
- Receive information from the caller
- Determine the Incident Level – 1,2,3
- Work to make the area safe
- Ensure external agency meeting point
- Contact engineering support if needed
- Activate SOP EOC if necessary
- Contact CEOC on call if needed
- Take actions to mitigate the emergency

↓

SOP EOC MEMBERS:
- Report to SOP EOC if activated
- Work with external agencies to mitigate the incident
- EOG Incident Commander will communicate with CEOC if necessary
- Maintain support & contact with OSC

↓

EXTERNAL AGENCIES:
- Receive request from On Call Supervisor, Observer, SOP EOC, etc
- Report to site and stage at security
- Work under direct supervision of Power Supply personnel
- Contain / Control the incident (OSC when on site)