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May 27, 2016

The 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 Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: The Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Phase Two – Teshmont Report

Enclosed please find the original plus 12 copies of the above-noted report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Legal Counsel

TLP/cp

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas Johnson, Q.C. – Consumer Advocate
Danny Dumaresque
ecc: Roberta Frampton Benefiel – Grand Riverkeeper Labrador

SUMMARY REPORT

OF

PROBABILISTIC BASED TRANSMISSION RELIABILITY ASSESSMENT – ISLAND INTERCONNECTED SYSTEM

NEWFOUNDLAND AND LABRADOR HYDRO

May 27, 2016

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1.0 INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) owns and operates much of the interconnected generation and high voltage transmission system on the Island of Newfoundland, known as the Island Interconnected System (IIS). At present the IIS is electrically isolated from the North American grid, and as such the system must be self-sufficient in meeting the electrical needs of customers on the island portion of the Province.

The largest load center on the IIS is the Avalon Peninsula with most significant peak load supplied to the greater St. John’s area. Hydro owns and operates a 490 MW heavy oil fired thermal generating station at Holyrood on the Avalon Peninsula, with the majority of other generation sources west of the Avalon Peninsula.

The sanctioned Muskrat Falls Phase I Project includes, among other infrastructure, development of the Muskrat Falls hydroelectric facility, the ±350 kV Labrador Island Transmission Link (LIL), the ±200 kV Maritime Link (ML) and a synchronous condenser plant at Soldiers Pond. The end result, once commissioned, will be the eventual shutdown of the Holyrood Thermal Generating Station (HTGS) as a primary producer of electrical power and energy. These system modifications will result in significant changes in the overall system loading and dynamic performance on the IIS.

The addition of ML provides Hydro with the opportunity to access power and energy from the North American market, if required, to meet customer demand during an unforeseen significant outage. Based upon existing transmission line capacity in the Maritimes, up to 300 MW can be imported to Newfoundland and Labrador from Nova Scotia under a LIL contingency.

Hydro’s current deterministic based Transmission Planning Criteria are similar to North American Electric Reliability Corporation (NERC) Transmission Planning standards; however, deviations from the NERC standards have been applied due to the isolated nature of the IIS and the potential cost impact of full compliance on the limited customer base.[1] In some areas of the industry, while not an established NERC standard, transmission planning is evolving to include probabilistic assessments similar to what is done for generation capacity planning. Hydro continues to utilize standard deterministic based Transmission Planning Criteria to assess the reliability of its IIS; however, Hydro engaged Teshmont Consultants LP (Teshmont) to provide a probabilistic based reliability assessment of its transmission system Pre-HVdc and Post-HVdc given the material system changes being implemented. The Teshmont reliability assessment is provided in Appendix A.

2.0 STUDY OBJECTIVE

The overall objective of the study was to complete a comparative probabilistic based assessment of the Island Interconnected System. The comparison is between the existing isolated transmission system, and the future interconnected transmission system including the HVdc transmission links.[2]

In addition to the HVdc Links to strengthen the system, the future state of the IIS includes:

- the rerouting of three existing 230 kV transmission lines into the 230 kV ac side of the Soldiers Pond Terminal Station;
- the addition of three high inertia 175 MVAR synchronous condensers;
- two new 230 kV transmission lines;
    - TL 267 – Bay d'Espoir to Western Avalon Terminal Station; and
    - TL 269 – Granite Canal to Bottom Brook Terminal Station.
- the construction of TL 266 to replace a section of TL 201 between Soldiers Pond and Hardwoods Terminal Station.

Of particular interest in the study is the impact that transmission system changes to the IIS (i.e.

[1] An historical balance between reliability and rates.
[2] There is no single universally accepted probabilistic reliability based value, or index, to demonstrate that a transmission network provides an acceptable level of reliability.

the replacement of the HTGS with an 1100 km long HVdc Link) will have on the power supply to the island's largest load center on the Avalon Peninsula.

3.0 STUDY DELIVERABLES

Hydro tasked Teshmont to study, assess and provide detailed results for the following objectives:

- Determine the appropriate forced outage rates for the HVdc Links with consideration to:
  - the converter technology;
  - overhead transmission; and
  - submarine cables.
- Document the forced outage rates for existing and proposed ac transmission system equipment with consideration to:
  - existing forced outage rates of Hydro owned equipment;
  - CEA industry average forced outage rates; and
  - the design standards such as return rate on meteorological loading conditions with respect to transmission line failures.
- Complete models of both the existing and future states;
- Complete a reliability based assessment of both states including, but not limited to:
  - overall unavailability;
  - Expected Unserved Energy (EUE);[3]
  - total outage time (hours/year); and
  - applicable assessment rates.
- Complete a comparison of the reliability indices for both states; and
- If necessary, propose system additions for the future system state to ensure the future state provides indices equal to, or better, than the existing system state.

[3] Expected unserved energy (EUE) is the summation of the expected number of MWh of load that will not be served in a given year as a result of demand exceeding available capacity.

4.0 REPORT CONCLUSIONS

The Teshmont report presents a comparative probabilistic reliability assessment for the IIS under Pre-HVdc and Post-HVdc conditions, including the development of both LIL and ML and the removal of the HTGS. The results of analysis indicated a substantial reliability improvement under Post-HVdc conditions.

A summary of the Teshmont conclusions are as follows:

- Without the ML, the EUE would increase by 2.7 GWh/year;
- The EUE resulting from ac transmission line outages is not material to the comparison of Pre-HVdc and Post-HVdc cases. Rather, this comparison is fundamentally between the reliability of the Holyrood units and the HVdc transmission links; and
- EUE resulting from the loss of Holyrood units Pre-HVdc in service is summarized in the following table:

Summary of Expected Unserved Energy and Probability of Sustained Unserved Load for Pre-HVdc Cases

Contingency	EUE based on CEA reliability data (GWh/year)	EUE based on Hydro reliability data (GWh/year)	EUE based on Hydro sensitivity reliability data (GWh/year)	Probability of Sustained Unserved Load (%)
Holyrood Units G1 and G2	5.3	16	23.5	12%
Holyrood Units G1, G2 , and G3	0.5	2.8	4.9	18%

- The materially reduced EUE post-HVdc in service is summarized in the following table:

Summary of Expected Unserved Energy and
Probability of Sustained Unserved Load for Post-HVdc Cases

Contingency	EUE (GWh/year)	Probability of Sustained Unserved load (%)
LIL HVdc Bipole (with ML)	0.00002	0%
LIL HVdc Bipole (without ML)	2.72	9%

- Based on CIGRE[4] data, the expected pole failure rate for the LIL is approximately 1.9 failures per year with an average duration of approximately 19.8 hours. These values are comparable to Hydro's assessment which included an expectation of 2.0 failures per year with an average pole outage duration of 21 hours. HVdc system design ensures that failure of one pole, as documented here, does not translate to customer outage.
- Based on outage data for voltage source converters, the availability of the ML is expected to be approximately 97.3%. This is consistent with the stated availability of the Maritime Link at 95% to 97%.[5]
- An overhead HVdc line failure rate of 0.19 outages/year/100 km with a duration of 1.78 hours per outage was used in previous Hydro analysis. These values were compared against Canadian Electricity Association (CEA) and CIGRE data. CEA and CIGRE data indicated that expected outage durations may be longer than the value proposed by Hydro. However, the overall forced outage rate of 0.00294% predicted by Hydro is comparable to the CIGRE value of 0.00388%.
- Submarine cable reliability data is site and system specific. For water depths greater than 100 m the data suggests a total failure frequency of 0.0071 failures/100km/year with a total outage time of 53 days or 1272 hours. The Hydro data provides an average pole failure rate of 0.0022/year on 30 km of cable, or an equivalent of 0.0073

[4] CIGRE (Council on Large Electric Systems) is an international non-profit association promoting collaboration with experts from around the world, producing reports on the state of the art from 16 study committees.
[5] Nova Scotia Power application to Nova Scotia Utility and Review Board.

failures/100 km/year with an average pole repair time of 4163 hours (173 days). It is acknowledged that the repair time is dependent upon factors such as ship availability, weather, ice conditions and removal of cable protection. It is understood that Hydro will be incorporating rock berms to protect the cable. Hydro’s use of a 4163 hour repair time may be reasonable considering the environment of the cable location. The material repair time requirement for the submarine cable justifies the spare cable, which is being constructed and will be maintained in service.

5.0 SUMMARY

This study presented a probabilistic reliability assessment comparison for the IIS under Pre- and Post-HVdc planned developments. The analysis performed by Teshmont provides validation of Hydro’s assumed HVdc reliability and availability parameters. The results of the Teshmont assessment also indicate a substantial reliability improvement for the Island Interconnected System under the Post-HVdc conditions.

Nalcor Energy

Probabilistic Based Transmission Reliability Assessment

Island Interconnected System

Prepared by:

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3061.001-100-Rev07
2016 May 27
[Rev06 Issued: 2016 May 25]

Nalcor Energy
Probabilistic Based Transmission Reliability Assessment
Island Interconnected System

Executive Summary

The purpose of this study is to assess the adequacy of Newfoundland and Labrador Hydro's Interconnected Island System (IIS) generation and transmission equipment under critical N-1 and N-2 contingencies on a probabilistic basis. A particular focus of the study was to evaluate the impact of the insertion of the Labrador Island Link (LIL) and Maritime Link (ML) HVDC systems with retirement of the Holyrood oil-fired thermal generation units in the Avalon Peninsula on system reliability.

A comparison was made between Pre-HVDC and Post-HVDC systems in terms of expected un-served energy to loads due to transmission and generation outages using PSS®E software. System security, i.e. the ability of the system to transition between each pre- and post-contingency operating condition and remain stable, was not assessed in this study. That is to say, the analysis does not include transient outages, but focuses on sustained outages only.

Expected un-served energy was calculated for each contingency by applying necessary corrective actions, such as generation re-dispatch or load shedding, to maintain transmission line loading and bus voltages within Newfoundland and Labrador Hydro's System Planning Criteria.

The reliability characteristics of the generation and transmission equipment were based on historical performance data provided by Nalcor. Reliability Data from CEA was used to perform a sensitivity analysis for generator outages. The reliability characteristics of the Labrador Island Link and Maritime Link were discussed in detail and compared to industry statistics.

Total expected unserved energy (EUE) for the Pre-HVDC 2017 Winter Peak case based on PSS®E probabilistic reliability analysis of Holyrood Thermal Unit outages is shown in the table below.

Contingency	E.U.E based on CEA reliability data (GWh/year)	E.U.E based on Hydro reliability data (GWh/year)	E.U.E based on Hydro sensitivity reliability data (GWh/year)
Holyrood Units G1 and G2	5.3	16	23.5
Holyrood Units G1, G2 , and G3	0.5	2.8	4.9

Taking into account the forecasted duration of load levels throughout the year, the exposure to expected unserved energy due to outages of units G1 and G2 would be expected for up to 12% of the year. Meanwhile, the exposure to expected unserved energy due to all Holyrood units combined outage would be up to 18% of the year.

The results of EUE analysis highlight the fact that, under Post-HVDC conditions the IIS reliability is improved substantially. The IIS would have a total expected EUE of 0.02 MWh per year. It is noted that without the ML, the EUE would increase to 2.72 GWh per year, as shown in the table below. Similar to Pre-HVDC/Holyrood units' outage scenario, this is considered only for up to 9% of the year based on the forecasted duration of load levels.

Contingency	E.U.E (GWh/year)
LIL HVDC Bipole (with ML)	0.00002
LIL HVDC Bipole (without ML)	2.72

It is also noted that expected unserved energy from transmission line outages improves from 100.8 to 41.9 MWh per year under Post-HVDC conditions.

Disclaimer

This report was prepared under the supervision of Teshmont Consultants LP ("Teshmont"), whose responsibility is limited to the scope of work as shown herein. Teshmont disclaims responsibility for the work of others incorporated or referenced herein.

Revision Number	Date Released	Prepared by	Reviewed by	Comment
Rev00	2014 September 17	FM/MH/NEK	SKMK	Draft
REV01	2014 October 22	FM/MH/NEK	SKMK	Comments on the draft have been addressed
Rev02	2014 November 4	FM/MH/NEK	SKMK	Conclusion section and additional analysis for Post-HVDC case
Rev03	2014 December 12	FM	SKMK	Minor editorial changes
Rev04	2015 February 12	FM	SKMK	Minor editorial changes
Rev05	2016 May 24	FM	SKMK	Minor editorial changes/Nalcor final comments
Rev06	2016 May 25	-	SKMK	Minor change to the Exec. Summary
Rev07	2016 May 27	-	SKMK	Correction for a typo in the Exec. Summary and Conclusion sections

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Nalcor Energy
Probabilistic Based Transmission Reliability Assessment
Island Interconnected System

1. Introduction

Newfoundland and Labrador Hydro (Hydro) owns and operates an interconnected generation and transmission system on the Island of Newfoundland, known as the Island Interconnected System (IIS). At present the IIS is electrically isolated from the North American grid, and as such the system must be self-sufficient in meeting the electrical needs of customers on the island portion of the province. Figure 1 provides a map of the IIS [20].

The largest load center in the IIS is the Avalon Peninsula located on the eastern portion of the island with the most significant peak load supplied by two 230/66 kV terminal stations located at Hardwoods and Oxen Pond. Hydro major hydro-electric generating stations are located west of the Avalon Peninsula at Bay d'Espoir, Upper Salmon, Granite Canal, Hinds Lake and Cat Arm. Hydro also owns a 490 MW heavy oil fired thermal generating station at Holyrood on the Avalon Peninsula. This generating station is normally operated during the winter months when hydro-electric resources and power purchases from non-utility generators cannot meet the system load [20].

In the past few years, two major generation and transmission projects have been started, which will connect the IIS to the rest of the North American grid. The first one is the Muskrat Falls project, which includes development of the 824 MW hydro-electric generating station at Muskrat Falls, two 315 kV ac transmission lines between Churchill Falls and Muskrat Falls, a 900 MW, ±350 kV HVDC transmission line between Muskrat Falls in Labrador and Soldiers Pond in Newfoundland (Labrador Island Link – LIL), and a synchronous condenser plant at Soldiers Pond. It will result in the shutdown of the Holyrood Thermal Generating Station as a primary producer of electric power and energy [20].

The second project is the Maritime Link (ML), which involves the construction of a ±200 kV, 500 MW HVDC transmission link between Bottom Brook Terminal Station in western Newfoundland and Woodbine Substation in Cape Breton, NS. On the IIS, Emera Newfoundland Limited (owner of the ML) will be constructing a new 230 kV transmission line between Granite Canal and Bottom Brook to provide sufficient transfer capacity for the ML. The addition of the ML provides Hydro with the opportunity to access power and energy from the North American market. Based upon existing transmission line capacity in the Maritimes, up to 300 MW can be exported from NS to NL under a LIL contingency. The two projects are shown in Figure 2. Figure 3 and Figure 4 show 2017-2018 winter peak transmission system configurations for IIS system before and after the insertion of ML and LIL HVDC projects [20].

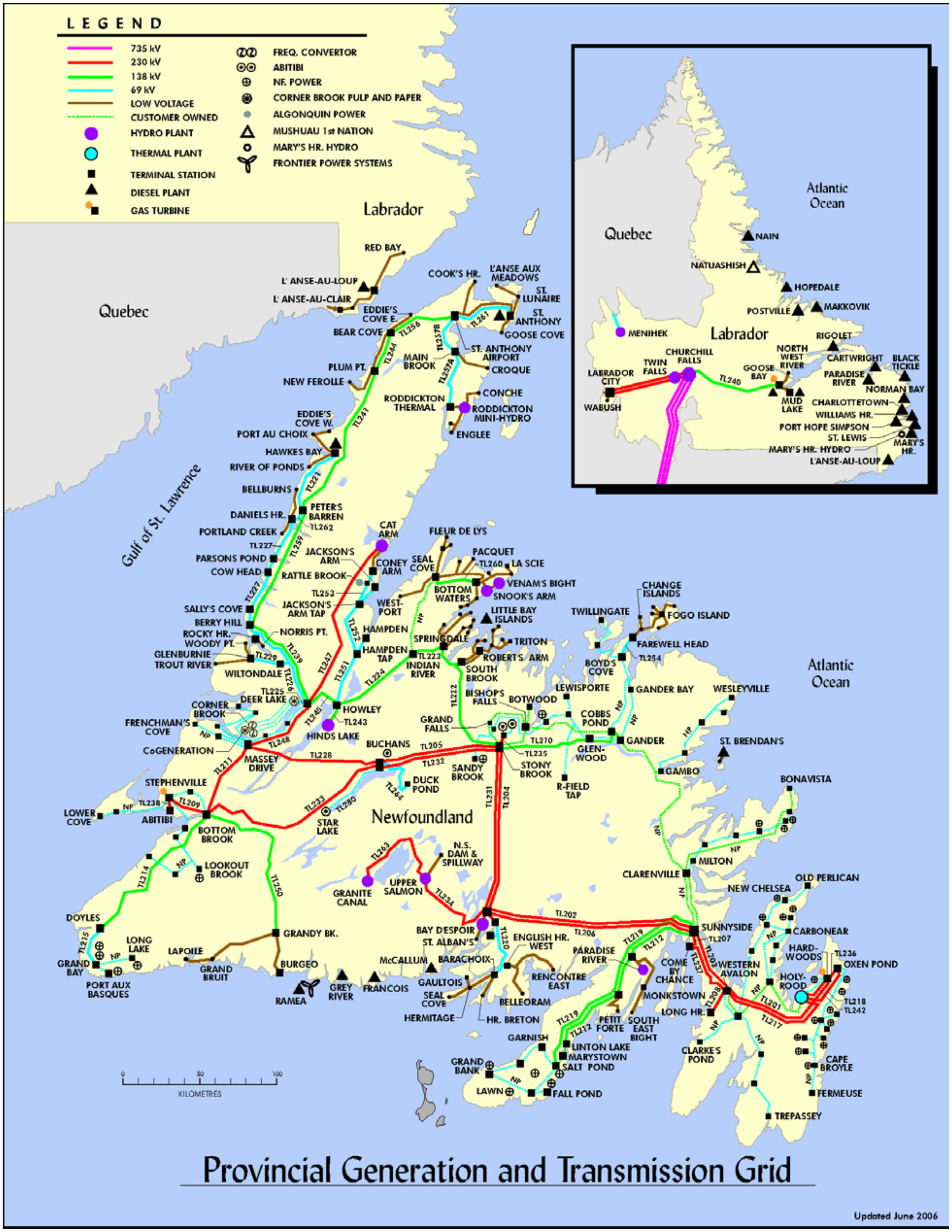

Figure 1: Island Interconnected System

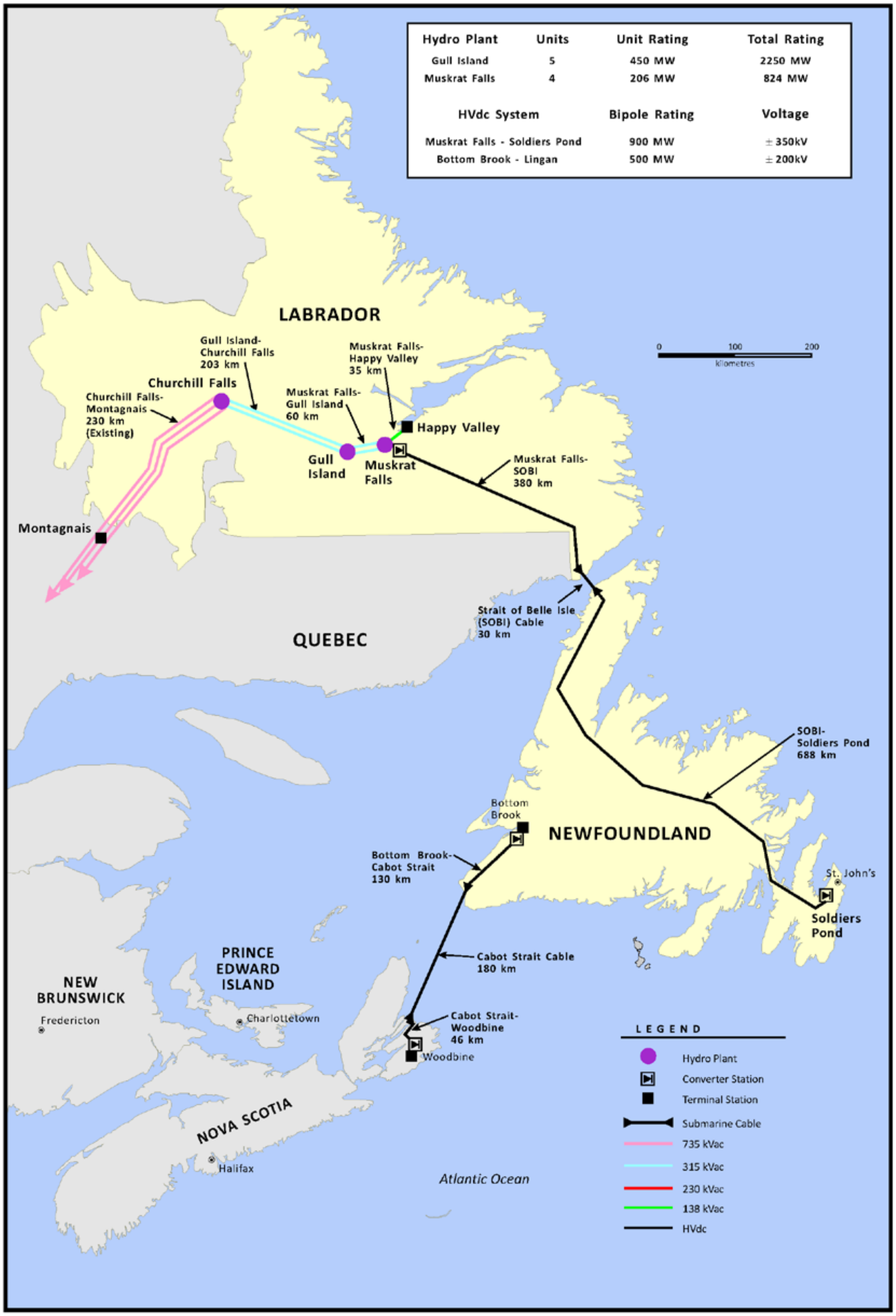

Figure 2: Muskrat Falls and Maritime Link projects

Teshmont

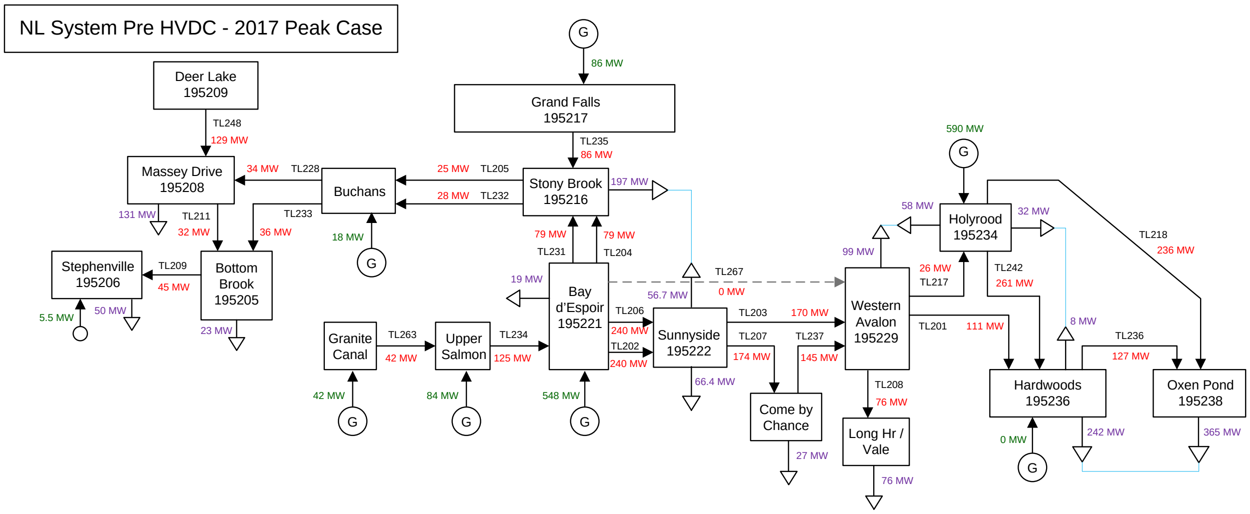

Figure 3: Major generation, load and transmission in the IIS before the HVDC links (existing state)

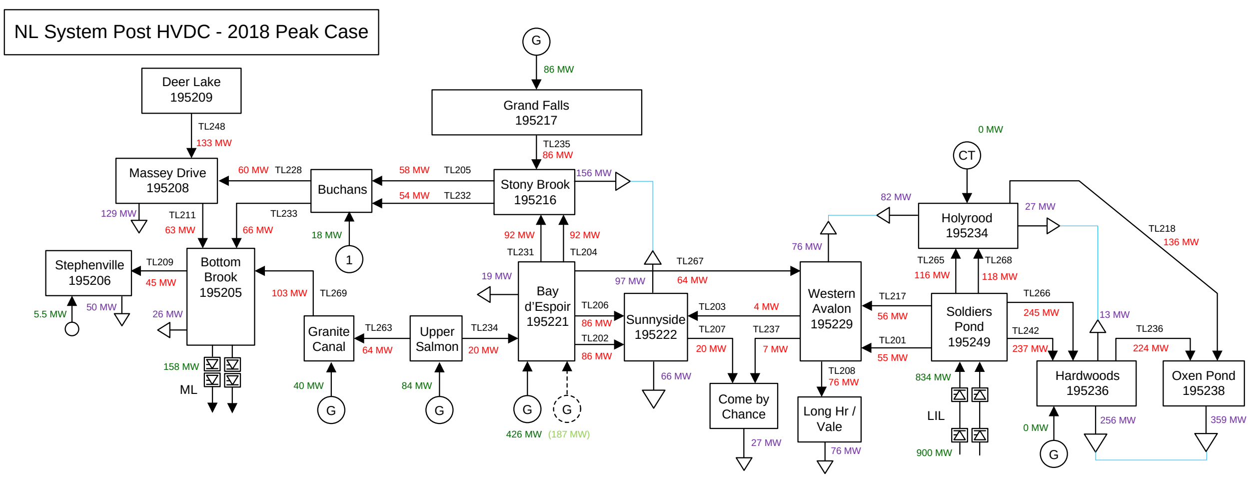

Figure 4: Major generation, load and transmission in the IIS with the HVDC links (future state)

This report presents the results of a probabilistic based reliability study that assesses the impact of the HVDC Links on the reliability of the IIS. The report compares the reliability of the existing transmission system and the future interconnected transmission system that includes the HVDC transmission links (future state) with the consideration of Holyrood thermal units' retirement. The main focus of the study was to assess the impact of the changes on the island's largest load center on the Avalon Peninsula.

2. Criteria and Assumptions

2.1. Base Cases

Two power flow cases were provided to use in the study. They are the NL System Pre-HVDC 2017 Winter Peak and the NL System Post-HVDC 2018 Winter Peak cases.

2.1.1. Generation

There are hydro units at Bay d'Espoir, Upper Salmon, Granite Canal, Hinds Lake and Cat Arm.

Existing thermal units at Holyrood are not online in the 2018 base case. The Holyrood units will be available in standby mode for the period 2018-2021. However, Unit 3 is left in service to operate as a synchronous condenser in the 2018 case.

There are combustion turbine units at Hardwoods, Holyrood, and Stephenville. These units are useful for compensating for unexpected generation shortages elsewhere in the system. These sources of generation are summarized in Appendix A.

2.1.2. 230 kV Transmission System

The 230 kV transmission system in the IIS in the Pre-HVDC 2017 base case consists of 25 transmission lines, as listed in Appendix B. These lines have a total length of 1608km.

The major transmission system differences going from the Pre-HVDC base case to the Post-HVDC base case are:

- Addition of Labrador Island Link
- Addition of Maritime Link
- Addition of Soldiers Pond converter station
- Reconfiguration of 230 kV transmission lines TL201, TL217 and TL242 resulting in the addition of 230 kV transmission line numbers TL265, TL266 and TL268 to accommodate Soldiers Pond terminal station
- Thermal upgrade of TL266
- Addition of 230 kV transmission line TL269 between Granite Canal and Bottom Brook terminal stations
- Addition of 230 kV transmission line TL267 between Bay d'Espoir and Western Avalon terminal stations

2.1.3. Loads

A significant part of the load in the IIS is located on the Avalon Peninsula and is supplied from Hardwoods and Oxen Pond Terminal Stations. Other major load centers are fed from Western Avalon, Holyrood, Stony Brook and Sunnyside Terminal Stations. The Total Load in the IIS was calculated as the sum of the constant power load and machine load in the IIS. For the Pre-

HVDC case, the total load is calculated to be 1705.6 MW. For the Post HVDC case, total load is calculated to be 1713.0 MW.

2.2. Simplified System Representation

Diagrams showing the 230 kV transmission system, major Hydro generation sources and load centers for the Pre-HVDC and Post-HVDC Peak Cases are shown in Figure 5 and Figure 6.

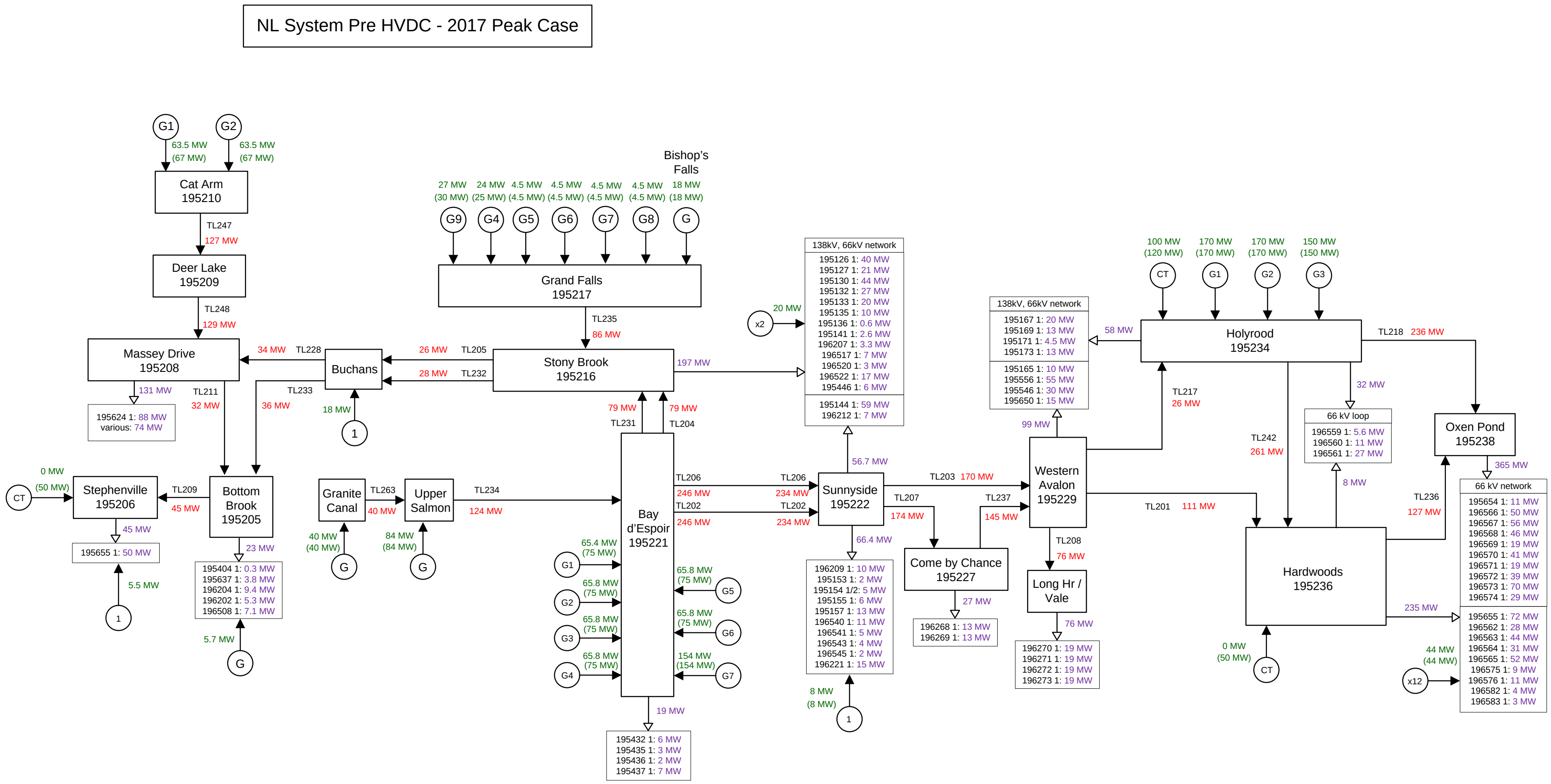

Figure 5: Simplified System Representation of Pre-HVDC Peak Case

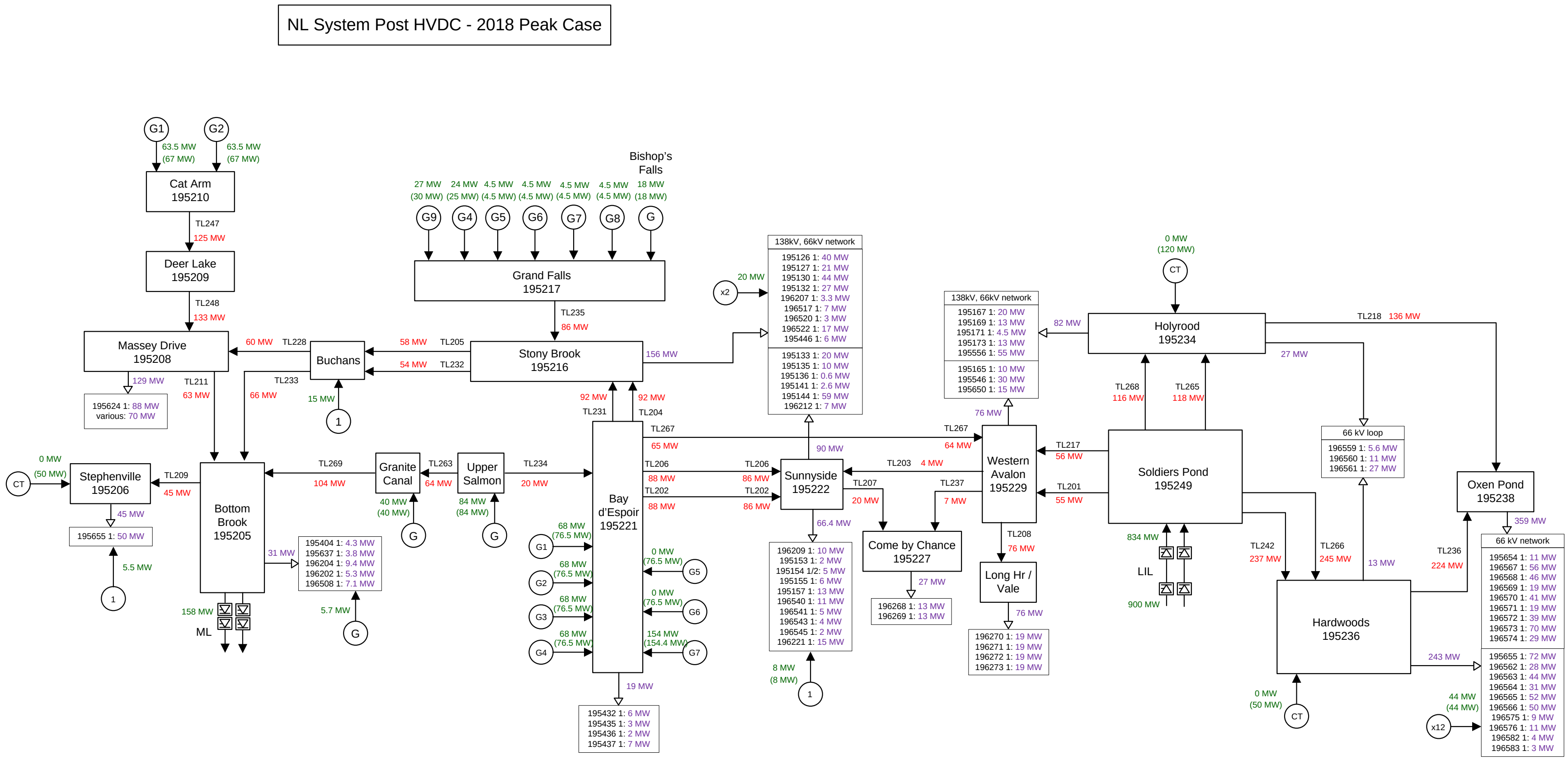

Figure 6: Simplified System Representation of Post-HVDC Peak Case

2.3. Load Shape and Load Duration Curves

A load shape curve and a load duration curve for the 2017 System Load were provided by Nalcor. They were developed by taking the average of the hourly loads from the years 2011, 2012 and 2013. The load shape for 2017 was generated using the calculated percent of peak load values and the forecasted peak system generation for 2017 of 1754.9 MW, taking into account industrial loads which were assumed to be constant throughout the year. The load duration curve was generated by counting the number of hours in a year that the load shape exceeded each percentage of peak load in increments of 1%. The 2017 load shape curve is shown in Figure 7 and the 2017 load duration curve is shown in Figure 8.

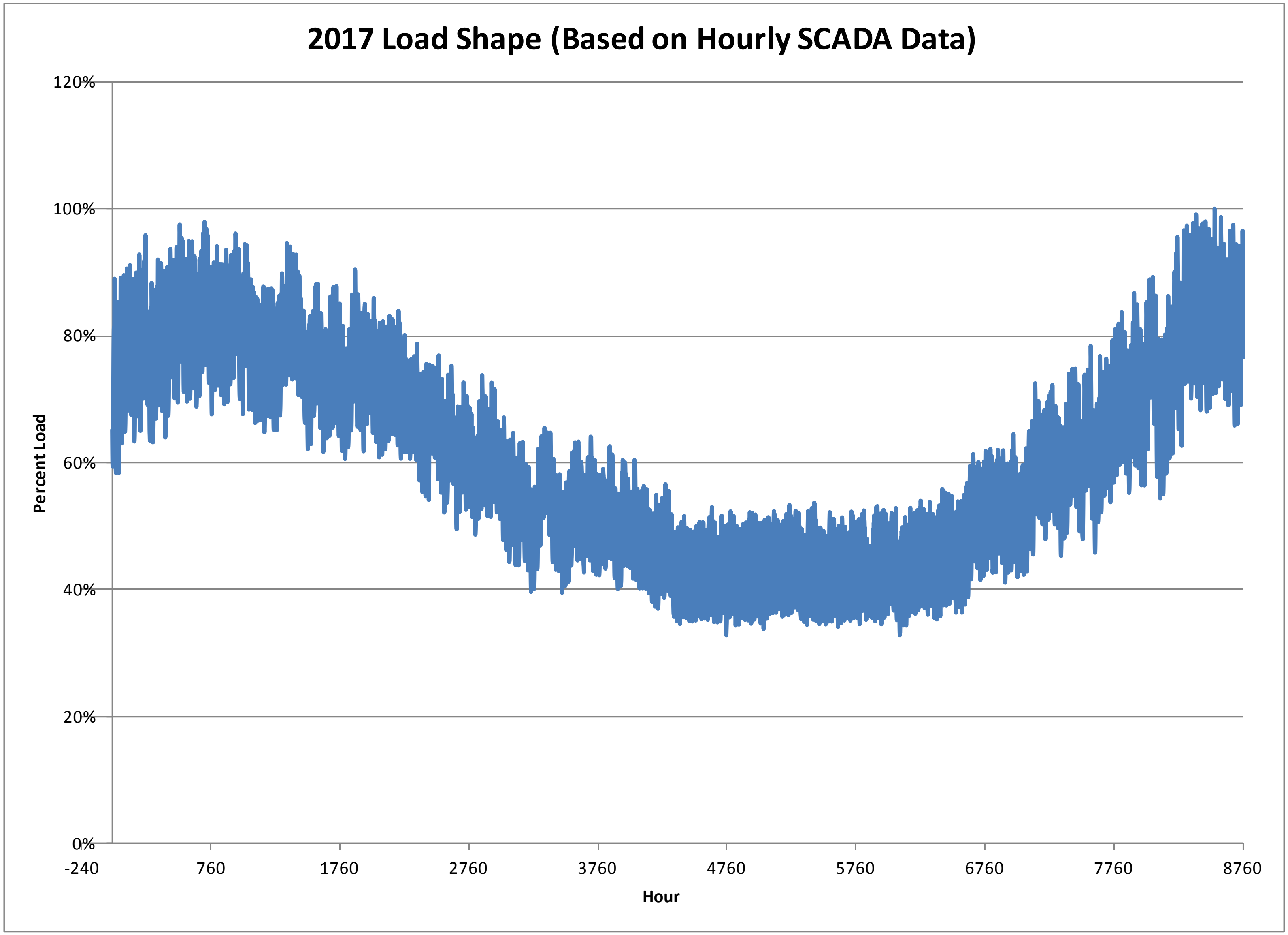

Figure 7: Modified 2017 Pre-HVDC System Load Shape Curve

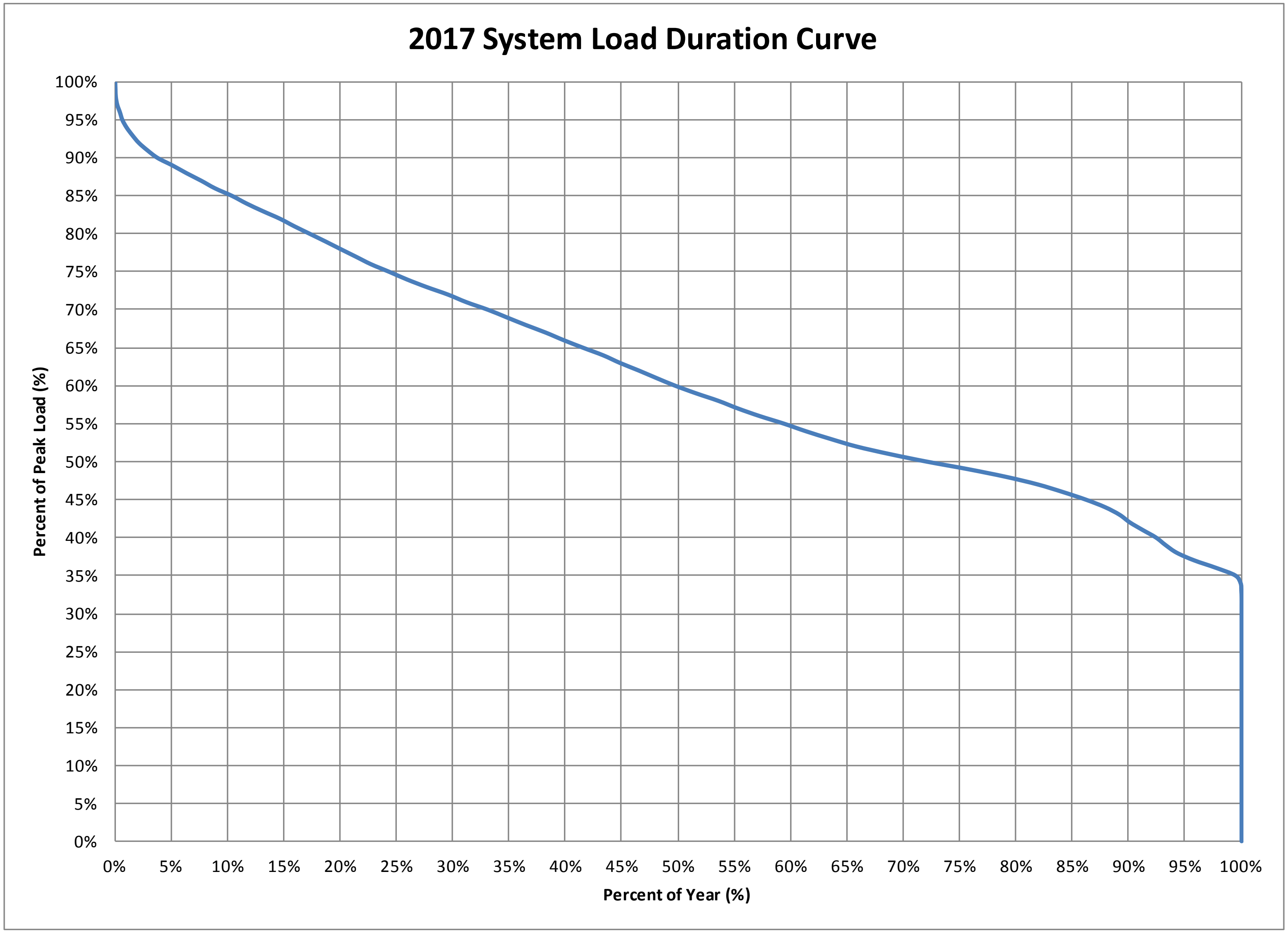

Figure 8: Modified 2017 Pre-HVDC System Load Duration Curve

2.4. Hydro System Planning Criteria

The planning criteria specified in the Summary of Newfoundland and Labrador Hydro's Transmission Planning Criteria [21] were followed in this study.

Of particular importance to this study were the following steady state analysis Criteria:

- With a transmission element (line, transformer, synchronous condenser, and shunt or series compensation device) out of service, power flow in all other elements of the power system should be at or below normal rating.
- For normal operations all voltages be maintained between 95% and 105%.
- For contingency or emergency situations all voltages must be maintained between 90% and 110%.

The remainder of the steady state analysis Criteria are as follows:

- Transformer additions at all major terminal stations (i.e. two or more transformers per voltage class) are planned on the basis of being able to withstand the loss of the largest unit.
- Analysis will be conducted with one high inertia synchronous condenser out of service at Soldiers Pond.

3. Software

This study was conducted using the following software packages:

- PSS®E version 33.5.90

4. AC System Reliability Data

Probabilistic reliability values for the 230 kV transmission lines, combustion turbines and the Holyrood thermal generating units were based on historical performance data and recommended values provided by Nalcor.

CEA data from 2012 for oil-fired generator reliability statistics was used to perform sensitivity analysis on generating unit outages in addition to the data provided by Nalcor.

4.1. Generating Units

4.1.1. CEA Data

The 2012 Generating Equipment Status Annual Report written by the Canadian Electricity Association (CEA) provides reliability statistics for generating units in Canada [22]. Table 1 shows the 2008-2012 average values for oil-fired fossil units and Hydro units. See Appendix C for definitions of reliability terms used in this report.

Table 1: CEA 2008-2012 Generating Unit Reliability Statistics

Type	Failure Rate (failures/year)	Mean Outage Duration (hours)	FOR (%)	DAFOR (%)
Fossil – Oil Units	7.11	72.06	8.1	9.23
Hydro Units	2.06	103.06	3.56	3.66

4.1.2. Hydro Data

Reliability data for 2008-2012 for IIS generating units is shown in Table 2 [23]. It should be noted that the DAFOR for hydraulic units weighted by maximum continuous rating (MCR) is 0.76.

Table 2: Generating Unit Performance Data 2008-2012

Type	Failure Rate (failures/year)	DAFOR - all units (%)
Holyrood Units	6.38	10.03
Hydro Units	2.62	1.22

In addition, Nalcor provided unit outage data and unit operating hours for Holyrood thermal units G1, G2 and G3 for the years 2009 to 2013. A summary of the outage data is shown in Table 3.

Table 3: Holyrood Thermal Unit Outage and Operating Data 2009-2013

Unit	Total Number of Forced Outages	Total Outage Time (hours)	Total Operating Time (Hours)
G1	30	6063	19921
G2	21	542	22502
G3	15	855	14084
Totals	66	7460	56507

4.2. Transmission Lines

Average failure rates and outage durations for the 25 existing 230 kV transmission lines were based on performance data for the five year period from 2009 to 2013 provided by Nalcor.

In total there were 163 outages, 77 of which were sustained outages (with durations greater than 1 minute). The sustained outages had a total duration of 703.74 hours. A summary of the 230 kV transmission line outage data are shown in Table 4.

Table 4: 230 kV Transmission Line Outage Data

Transmission Line	Total Number of Outages	Number of Sustained Outages	Total Outage Duration (Hours)
TL201	33	12	20.350
TL202	9	5	36.500
TL203	2	1	13.620
TL204	8	2	0.120
TL205	9	1	0.370
TL206	2	2	1.750
TL207	1	1	2.270
TL208	21	6	401.120
TL209	2	2	30.080
TL211	8	6	6.850
TL217	6	3	3.750
TL218	6	6	58.420
TL228	20	9	77.070
TL231	6	2	0.380
TL232	5	1	39.200
TL233	4	3	0.220
TL234	6	3	0.330
TL235	0	0	0.000
TL236	0	0	0.000
TL237	2	2	1.120
TL238	0	0	0.000
TL242	2	1	0.600
TL247	6	5	8.100
TL248	1	0	0.000
TL263	4	4	1.520

4.3. Calculation of Reliability Statistics

This section describes the methods used to calculate the reliability statistics (average failure rates and average outage durations) for the generating and transmission equipment. All reliability definitions and standards, associated with generation and transmission, are illustrated in Appendix C.

4.3.1. Holyrood Thermal Units

Generator reliability statistics were calculated using CEA reliability data shown in Section 4.1.1 and the formulas in Appendix C, and are shown in Table 5.

Table 5: Equivalent Reliability Statistics based on CEA Data N-2 Thermal Unit Contingencies

Contingency	Failure Rate (outages per year)	Average Outage Duration (hours)
Holyrood units G1 and G2	0.7446	36.03
Holyrood units G1, G2 and G3	0.062	24.02

Nalcor uses a common derating adjusted forced outage rate (DAFOR) of 9.64% for all three units, and a value of 11.64% for a sensitivity analysis. Generator reliability statistics were calculated using the unit data provided by Nalcor shown in .

Table 3, the recommended values for unavailability and the formulas shown in Appendix C. Based on the outage and operating data, a failure rate of 10.23 failures/year, average outage duration of 113 hours, and an unavailability of 11.64% were derived. Furthermore, some of the Holyrood unit outages were extensive in duration as repairs were not performed immediately in cases when units were scheduled to come offline in the spring. These cases were considered extreme in duration and unrepresentative of the reliability of the generating units. The average outage duration could therefore be reduced to 91.4 hours, while keeping the failure rate at about 10.23/year, resulting in an unavailability of 9.64%. However, it was also believed that it would still be useful to include a sensitivity analysis using a forced outage rate based on the totality of the outage data in the data period. Finally, reliability statistics for N-2 outages of Holyrood units were calculated using the statistics for single unit outages and the formulas shown in section Appendix C. The calculated outage statistics are shown in Table 6.

Table 6: Thermal Unit Reliability Statistics based on Hydro Data

Contingency	Failure Rate (outages per year)	Average Outage Duration (hours)
Holyrood unit G1	10.23	91.40
Holyrood unit G1 - sensitivity	10.23	113.0
Holyrood units G1 and G2	1.800	45.7
Holyrood units G1 and G2 – sensitivity	2.136	56.5
Holyrood units G1, G2 and G3	0.258	30.47
Holyrood units G1, G2 and G3– sensitivity	0.369	37.67

Expected unserved energy values were calculated using both CEA and Nalcor reliability statistics, as presented in section 6.2.1.

4.3.2. Combustion Turbines

Nalcor uses a UFOP of 10.62% (also 20.62%) for their existing combustion turbine units (Hardwoods and Stephenville), and a UFOP of 5% for the Holyrood 120 MW CT.

4.3.3. 230 kV Transmission Lines

The average failure rates and average outage duration for the 230 kV transmission lines were calculated based on the data shown in Table 4. However, Nalcor advised that the outages for TL201 and TL208 should be excluded from the calculations [25]. It was explained that TL201 had insulator issues that were recently discovered and that have affected its reliability in the past five years, and that TL208 had no customers for a prolonged period of time and failures were repaired at a lower priority.

Based on a total of 59 sustained outages over 23 transmission lines with a total length 1510 km, an average failure frequency of 0.781 outages per 100 km per year was calculated. This frequency was then multiplied by the length of each line and divided by 100 to determine the average failure rate in outages per year for line. This approach was considered valid because five years of data was considered insufficient to provide statistically meaningful data for individual lines, but it would be meaningful for the entirety of the 230 kV system.

Based on a total duration of 282.25 hours for 59 sustained outages, an average outage duration of 4.784 hours was calculated. This is consistent with the average duration for sustained outages of 230 kV transmission lines on the Avalon Peninsula, which is the focus of this analysis. Therefore the same average outage duration was applied to all lines, as shown in Table 7.

Outages due to ac terminal station equipment such as circuit breaker failures or misoperations are not included in this analysis. It is assumed that such events will be rare given regular maintenance and condition monitoring practices. There would therefore be no appreciable difference in system reliability due to ac terminal station equipment in the Pre-HVDC and Post-HVDC cases.

Table 7: 230 kV Transmission Line Average Failure Rates and Outage Duration

Transmission Line	Length (km)	Failure Frequency (outages per 100 km per year)	Failure rate (outages per year)	Average Outage Duration (hours)
TL201	80.678	0.781	0.630	4.784
TL202	141.758	0.781	1.107	4.784
TL203	44.534	0.781	0.348	4.784
TL204	105.021	0.781	0.820	4.784
TL205	83.937	0.781	0.656	4.784
TL206	141.927	0.781	1.108	4.784
TL207	6.671	0.781	0.052	4.784
TL208	14.711	0.781	0.115	4.784
TL209	21.056	0.781	0.164	4.784
TL211	55.68	0.781	0.435	4.784
TL217	76.663	0.781	0.599	4.784
TL218	37.294	0.781	0.291	4.784
TL228	84.77	0.781	0.662	4.784
TL231	105.31	0.781	0.822	4.784
TL232	84.247	0.781	0.658	4.784
TL233	135.847	0.781	1.061	4.784
TL234	51.538	0.781	0.403	4.784
TL235	0.62	0.781	0.005	4.784
TL236	10.338	0.781	0.081	4.784
TL237	44.95	0.781	0.351	4.784
TL238	0.862	0.781	0.007	4.784
TL242	27.21	0.781	0.213	4.784
TL247	122.909	0.781	0.960	4.784
TL248	55.119	0.781	0.430	4.784
TL263	74.761	0.781	0.584	4.784

The equivalent failure rates and outage durations for double (N-2) transmission line contingencies were calculated using the formulas in Appendix C and shown in Table 8.

Table 8: Double (N-2) Transmission Line Contingency Average Failure Rates and Outage Duration

Transmission Lines	Failure rate (outages per year)	Average Outage Duration (hours)
TL201-TL236	5.557E-05	2.392
TL201-TL242	1.463E-04	2.392
TL203-TL237	1.334E-04	2.392
TL206-TL202	1.340E-03	2.392
TL203-TL207	1.979E-05	2.392
TL218-TL236	2.569E-05	2.392
TL218-TL242	6.761E-05	2.392
TL236-TL242	1.874E-05	2.392

The 230 kV transmission line reliability statistics calculated for the Post-HVDC case are shown in Table 9. This table only includes lines that are either unique to the Post-HVDC Case or whose lengths differ from the Pre-HVDC Case.

Table 9: 230 kV Transmission Line Reliability Statistics for Post-HVDC Case

Transmission Line	Length (km)	Failure Frequency (outages per 100 km per year)	Failure rate (outages per year)	Average Outage Duration (hours)
TL201	65.350	0.781	0.510	4.784
TL217	65.380	0.781	0.511	4.784
TL242	16.050	0.781	0.125	4.784
TL265	11.160	0.781	0.087	4.784
TL266	15.330	0.781	0.120	4.784
TL267	186.294	0.781	1.455	4.784
TL268	11.280	0.781	0.088	4.784
TL269	180.0	0.781	1.406	4.784

The equivalent failure rates and outage durations calculated for double (N-2) transmission line (or one line and the Holyrood CT) contingencies are shown in Table 10.

Table 10: Double (N-2) Contingency Reliability Statistics for Post-HVDC Case

Contingency	Failure rate (outages per year)	Average Outage Duration (hours)
TL265-TL268	8.387E-06	2.392
TL218-TL236	2.569E-05	2.392
TL242-TL266	1.639E-05	2.392
TL265-Holyrood CT	5.366E-03	3.885

5. HVDC Reliability Data

This section presents the reliability data that was used in the study for the LIL and the ML.

5.1. Description of HVDC Links

This section provides a short description of the HVDC links.

5.1.1. Labrador Island Link

The proposed LIL will carry electricity from the generating facility at Muskrat Falls to the island of Newfoundland. It will be a 1,100 km long HVDC transmission system, running from central Labrador, crossing the Strait of Belle Isle, and extending to Newfoundland's Avalon Peninsula as shown in Figure 9. The transmission project includes [2]:

- A converter station at Muskrat Falls (Labrador)
- 380 km of overhead HVDC transmission line from the Muskrat Falls converter station to the Strait of Belle Isle at Forteau Point.
- 30 km submarine HVDC cable crossing across the Strait of Belle Isle, from Forteau Point, Labrador to Shoal Cove, Newfoundland.
- 688 km of overhead HVDC transmission line from Shoal Cove to Soldiers Pond, Newfoundland.
- A converter station at Soldiers Pond (Newfoundland)
- Electrodes, or grounding systems, at L'Anse au Diable (on the Labrador side of the Strait of Belle Isle) is 400 km away from Muskrat Falls (two circuits - continuously monitored). Meanwhile, at Dowden's Point (in Conception Bay, Newfoundland), it is 10 km away from Soldiers Pond.

Figure 9: Labrador Island Link

5.1.2. Maritime Link

The Maritime Link (ML) is a new 500 MW (+/- 200 kV) HVDC system that connects Bottom Brook Terminal Station in western Newfoundland to Woodbine Substation in Cape Breton, NS. The following paragraphs briefly describe the infrastructures that are associated with this link [1].

On Newfoundland side, the ML includes an estimated 130 kilometres of HVDC overhead transmission line between Bottom Brook and Cape Ray. The associated infrastructure will include two switchyards, one converter station, one transition compound, one onshore cable anchoring site, one grounding site, roughly 20 kilometres of grounding line, and about two kilometres of underground cable.

The ML also includes two submarine HVDC cables, each approximately 180 kilometres long, that span across the Cabot Strait from Cape Ray on the island of Newfoundland to an area west of the Nova Scotia Power Inc. (NSPI) Point Aconi generating station in Cape Breton. This portion of the Project includes two landfall sites where the cables will come ashore in Nova Scotia and on the island of Newfoundland.

On Nova Scotia side the ML includes fewer than 46 kilometres of new HVDC transmission line between a point on the west side of the Point Aconi generating station and an existing substation at Woodbine. Associated infrastructure includes one converter station, one transition compound, one onshore cable anchoring site, one grounding site, roughly 40 kilometres of grounding line and two one-kilometer sections of underground cable.

5.2. Data Provided by Nalcor Energy

The forced outage rates and availability of the HVDC systems are highly dependent on their design, installation, and location (for example availability of a spare converter transformers and/or submarine cables can significantly improve the reliability of the overall system). Therefore, unless details of a specific system are available, an accurate estimate of its forced outage rates and availability cannot be calculated. For the purpose of this study, Teshmont is planning to use the following values, which are based on the information that was provided to Teshmont by Nalcor Energy.

5.2.1. Labrador Island Link

According to the section 14.6.1 of the Lower Churchill project performance requirements [4], here are the reliability requirements for the converters for the LIL:

- Pole Forced Outage Rate ≤ 5.0 per pole per year
- Bipole Forced Outage Rate ≤ 0.1 per bipole per year
- Forced Energy Unavailability ≤ 0.50%
- Scheduled Energy Unavailability ≤ 1.0%

Nalcor in conjunction with SNC Lavalin conducted a reliability study for the LIL [5]. Here is a summary of the assumptions and the results of the study.

5.2.1.1. HVDC Converters

Based on the Nalcor study the following are the expected failure rates and repair times for the HVDC converters of the LIL.

- Average pole failure rate per terminal: 2/year
- Average repair time for pole outages: 21 hours
- Average Bipole failure rate per terminal: 0.2/year
- Average repair time for Bipole outages: 1.3 hours

5.2.1.2. HVDC Overhead Lines

Based on the Nalcor study the following are the expected failure rates and repair times for the HVDC overhead lines.

- Average failure rate per pole (based on 1100km length): 2.101/year
- Average repair time: 1.78 hours
- Average common mode failure rate: 0.02/year/100km
- Average common mode repair time: 24 hours

5.2.1.3. HVDC Submarine Cables

Based on the Nalcor study the following are the expected failure rates and repair times for the HVDC submarine cables. It is worth mentioning that a spare cable is considered to be in-service (available), therefore, the loss of a pole would require the loss of two cables. The complete loss of the link would require the loss of all three cables/pole.

- Average pole failure rate: 0.0022/year
- Average pole repair time: 4163 hours
- Average failure rate for complete loss of the link: 0.001/year
- Average repair time for complete loss of the link: 4380 hours

5.2.1.4. Electrode Lines

According to the LIL reliability study [5], the CEA outage statistics for ac lines up to 109kV were used to indicate an average failure rate for the electrode lines of 5 outages/100km/year with an average repair time of 8.2 hours. This value includes both sustained and transient outages, as per the CEA statistics. The sustained average outage rate is only 2.7 outages/100km/year and the average outage time is 17.4 hours [16]. With the application of these statistics over almost the 400 km of the electrode line, it results in 10.8 outages/year. However, this appears to be a high value associated with electrode lines which are lightly loaded most of the time. The assumption of actual 10% outages (1.1 outages/year), with the same average outage time, seems reasonable considering the continuous monitoring of the electrode line.

For a common failure mode, i.e. outage of both electrode circuits, a failure rate of 0.01outages/year with an average repair time of 17.4 hours can be assumed. Losing both electrode lines won't stop the LIL from operating, possibly it can operate with the unbalance current handled by the station ground or operating at reduced power in mono-polar mode using metallic return.

In addition, and in agreement with what was stated in the study, the above analysis would be considered only if the electrode lines will be constructed on a separate wood-pole line. As the electrode lines will be installed on the main dc line towers, the reliability of the electrode lines is expected to be included in the common mode failure of the dc line. Given that the electrode line in Labrador will be constructed on the main dc line towers for much of its length, it is not anticipated that the LIL's relatively long electrode line will impact or have a major influence on LIL overall reliability.

5.2.1.5. Complete System

According to the Nalcor study, here are the failure rates and the average repair times for the complete link.

- Bipole failure rate and repair time:
    a. Average failure rate: 0.7078/ year
    b. Average repair time: 13.49 hours

- Reduced power operation (pole failure rate and downtime):
  a. Average failure rate: 9.36/ year
  b. Average downtime: 214.6 hours

Based on the above figures the average repair time for pole outages is about 22.9 hours. The above mentioned bipole failure rate and repair time values are used in section 6.2 (system overall probabilistic reliability analysis) below.

5.2.2. Maritime Link

In accordance with Nova Scotia Power's responses IR-5 [6] and IR-35 [7] in support of the application of the Maritime Link Project before the Nova Scotia Utility and Review Board, the availability of the ML is assumed to be between 95% and 97%.

5.3. Available Outage Statistics

This section presents the available outage statistics for a number of existing HVDC systems across the world. Please note that, as mentioned before, the forced outage rates and availability of the HVDC systems are highly dependent on their design, installation, and location. Therefore, statistics obtained from one system may not be applicable to another system. However, the figures presented here may be used as a reference to evaluate the results of the previous Nalcor reliability studies.

5.3.1. Line Commutated Converters

Every two years the International Council on Large Electric Systems (CIGRE) working group B4 publishes outage statics of a number of HVDC schemes in the world. In this report the CIGRE data from 2001 to 2010 [8] - [12] was used to estimate the reliability of a bipole HVDC scheme. This was the most recent data available at the time this report was initiated. An assessment of more recent data [sources] indicates that this data is still reasonable and representative of Lin Commuated HVDC systems. The data for the following schemes was used for this estimation:

- Square Butte
- Nelson River BP1
- Nelson River BP2
- Hokkaido-Honshu
- Itaipu BP1
- Itaipu BP2
- Rihand-Dadri
- Great River Energy's CU HVDC

Since this section only considers the reliability of the converter station, the outages that were caused by transmission lines or cables, were excluded from the analysis. The results are as follows:

- Average failure rate: 3.7/year
- Average repair time per outage: 9.9 hours

Please note that CIGRE reports equivalent forced outage hours and not the actual outage times. Equivalent forced outage hours is the sum of the actual forced outage hours after the outage duration has been adjusted for the percentage of reduction in capacity due to the outage. For example, for an outage of one pole of a bipole system (50% loss of capacity) that lasted two hours, the equivalent outage hours would be one hour. Assuming that most HVDC outages are single pole outages, the actual average repair time should be about twice the number above or about 19.8 hours.

Based on Nalcor study for the LIL [5], it seems that the expected pole failure rate for the LIL converters per terminal is about 2 failures per year and the average pole outage duration is about 21 hours. If it is assumed that most of the HVDC outages are single pole outages, based on the CIGRE data, the expected pole failure rate for a bipole HVDC system per terminal is about 1.9 failures per year and the average pole outage duration is about 19.8 hours. These numbers are close to the figures that Nalcor/ SNC Lavalin study estimated.

5.3.2. Voltage Sourced Converters

There is only a limited amount of data available on the performance of the Voltage Sourced Converter (VSC) based HVDC systems. Reference [19] provides data on the operating experience of two VSC-based HVDC systems, i.e. Cross Sound Cable (CSC) project and Murray Link, which have been in operation since 2002. Both of the schemes use HVDC light technology in bipole configuration. Based on [19] the average forced energy unavailability (FEU) of the CSC project and the Murray Link were about 1.15% and 2.35% respectively. The high level of FEU for the Murray link is mainly due to a long outage in 2007. According to [19], this outage was caused by a fire on top of one of the phase reactors that led to the outage of the reactor. The outage time was unusually long as the converter building was not designed to accommodate easy replacement of the phase reactor, and the building did not contain the contaminations from the fire, which increased the cleaning time. Proper design of the converter building can help to avoid such long outages. If the long outage of 2007 is excluded from the data, Murray Link had a FEU of 1.06%. Based on [19] the average scheduled energy unavailability (SEU) of the CSC project and the Murray Link were about 2.07% and 1.73% respectively. The two schemes were two of the first VSC-based schemes at this power level. According to [19], this significant increase in power transfer and DC operating voltage created some unforeseen design and operations issues, which increased the scheduled outages to fix problems or install revisions. Therefore, it is expected that the above availability figures improve as the VSC technology matures.

In [15], authors used historical data of conventional HVDC systems compiled by CIGRE for the years 2005 and 2006 [10] to estimate reliability of VSCs. As the two technologies (conventional converters and VSCs) are similar in many aspects, historical data of conventional systems can provide a reasonable estimate of the reliability of VSC-based systems. However, since some of the components that exist in conventional systems do not exist in VSC-based systems, in [15] only part of the historical data was used. The CIGRE report on reliability of conventional HVDC systems classifies HVDC outages into six categories, as follows:

- AC and auxiliary equipment (AC-E)
- Valves (V)
- Control and protection (C&P)
- DC equipment (DC-E)
- Other (O)
- Transmission line or cable (TL)

In [15], authors assumed that the reliability of VSCs is only affected by faults in valves, control and protection system, and dc equipment. As result, the outages that were reported in the other categories were not considered. The resulting average forced outage statistics are shown in Table 11.

Table 11: Average forced outage statistics for HVDC converters during 2005 – 2006

Category	Average Outage Rate [1/year]		Average Outage Duration [hours]*	
	2005	2006	2005	2006
Valves	1.4	1.5	3.7	2.3
Control and Protection	1.7	2.1	2.0	3.9
DC Equipment	1.1	0.7	5.9	6.9
Average Total	4.3		4.1	
Average Total per Converter	1.4			

* Excluding one exceptionally long outage duration of 1743 h

Using the above data and outage statistics for other HVDC equipment, the authors then estimated the availability of power transfer capacity for a VSC-based bipole HVDC scheme. It was shown that 100% of power transfer capacity is available for about 97.4% of the time (not including the impact of the transmission lines and scheduled outages) [15].This results in a FEU level of about 1.3% for a bipole system (assuming that the majority of HVDC outages are single pole outages).

To summarize the above, both the operating experience and the above estimation show that FEU levels of about 0.6% per converter are achievable by the VSC technology. In addition, according to the limited operating experience it seems that SEU levels of about 1.5% are also achievable. Based on this, the overall energy availability of a bipole system will be about 97.3% (not including the impact of transmission lines/cables and bipole failures).

5.3.3. HVDC Overhead Lines

Unfortunately, only a limited amount of historical data is available for the HVDC overhead lines. Here the CIGRE outage statistics [8] - [12] for the following HVDC systems have been summarized. The outage statistics is for a 10 year period between 2001 and 2010.

Teshmont

- Square Butte
- Nelson River BP1
- Nelson River BP2
- Itaipu BP1
- Itaipu BP2
- Rihand-Dadri
- Great River Energy's CU HVDC

Based on the data, the average failure rates and the average outage duration for the HVDC overhead lines are as follows.

- Average pole failure rate: 0.092/year/100km
- Average pole repair time per outage: 11.7 hours

Please note that the Square Butte HVDC system was frequently hit by tornados, which results in significant outage durations for this system. If the Square Butte is removed from the data, the average failure rates and outage durations will be as follows.

- Average pole failure rate: 0.089/year/100km
- Average pole repair time per outage: 2.9 hours

Since pole outages have a significantly higher frequency than bipole outages, in estimation of the above outage rates it was assumed that all reported outages in the CIGRE data were pole outages. Please note that as mentioned before, CIGRE reports equivalent forced outage hours and not the actual outage times. Assuming that most HVDC outages are single pole outages, the actual average repair times with and without considering Square Butte should be about twice the numbers above or about 23.4 hours and 5.8 hours respectively.

The above systems use Line Commutated Converters (LCCs). LCCs are not susceptible to transient faults on the dc lines, as in case of a temporary fault, they can stop the dc fault current, wait until the fault is cleared, and resume operation. However, at present some of the Voltage Sourced Converter (VSC) technologies do not have the ability to stop dc fault currents; therefore, in case of a temporary dc fault, the converter ac breakers should be opened. This may result in considerable outage durations and may affect the overall system reliability. The susceptibility of VSCs to dc faults can be reduced by using dc breakers [13] or full bridge converter topologies [14].

Another method for estimating the reliability of HVDC overhead lines is to use outage statistics for HVAC lines. Please note that the temporary pole fault rate for HVDC lines is expected to be slightly higher than the single-phase faults on HVAC lines. This is due to the higher risk of back flashovers across the insulators for the positive pole when the tower is hit by negative lightning strokes [15].

The following table shows a summary of transmission line statistics for line-related sustained forced outages between the years 2007 and 2011. The data is based on the Canadian Electricity Association (CEA) report [16].

Table 12: Summary of Transmission Line Statistics for Line-Related Sustained Forced Outages

Voltage Classification	Kilometre Years (Km.a)	Number of Outages	Total Time (h)	Frequency (Per 100 Km.a)	Mean Duration	Unavailability (%)
Up to 109 kV	66,318	1,780	30,951	2.6841	17.4	0.533
110 - 149 kV	211,964	1,983	37,880	0.9355	19.1	0.204
150 - 199 kV	10,520	100	403	0.9506	4	0.044
200 - 299 kV	169,693	714	25,997	0.4208	36.4	0.175
300 - 399 kV	40,141	105	843	0.2616	8	0.024
500 - 599 kV	50,042	122	3,211	0.2438	26.3	0.073
600 - 799 kV	35,280	38	12,276	0.1077	323.1	0.397

Considering the voltage levels for LIL and ML the average outage rates and durations for LIL and ML overhead lines are as follows. Please note that the outage rates in the above table are for overall three phase system; therefore, per phase values were estimated by dividing the above numbers by 3.

Labrador Island Link:

- Average pole failure rate: 0.140/year/100km
- Average pole repair time per outage: 36.4 hours

Maritime Link:

- Average pole failure rate: 0.312/year/100km
- Average pole repair time per outage: 19.1 hours

As seen in the CEA results, the average repair times for ac overhead lines are considerably higher than that of dc overhead lines. However, the CEA statistics includes repair times for structural damages. If the outages that were caused by structural damages are taken out, the above average repair times significantly decrease.

It is worth mentioning that based on CIGRE (Square Butte's contribution is excluded) and Nalcor report data for the LIL [5], the forced outage rate (FOR) would be 0.00388% and 0.00294%, respectively. In summary, the average failure rate that was used in the previous Nalcor study for the LIL is slightly higher than the figures that were estimated based on the CIGRE and CEA data, while the average repair time in the Nalcor study is considerably lower.

5.3.4. HVDC Submarine Cables

CIGRE provides outage reports on HV underground and submarine cable systems [17]. The outage data for submarine cables were collected between 1990 and 2005. According to CIGRE during this period there were in total 49 faults on AC and DC submarine cables out of which 27 of them were on AC submarine cables and 22 of them were on DC submarine cables. At the end of 2005, the total quantity of installed AC and DC submarine cable circuits were 3697 km and 3366 km respectively out of which 1758 km of AC cables and 2084 km of DC cables were installed between 1990 and 2005. Therefore as a high level estimate the failure rates for the submarine cables are as follows:

- Average failure rate for AC submarine cables: 0.060/year/100km/circuit
- Average failure rate for DC submarine cables: 0.059/year/100km/circuit

Please note that the above numbers are based on CIGRE data in which the faults caused by cable accessories were also included. According to CIGRE if the extreme and unknown cases are excluded, the average repair time of submarine cables is approximately 60 days. It should be noted that repair times of submarine cables is affected by many factors (availability of spare cable and accessories, availability of appropriate vessel, weather conditions, etc.) that can lead to a wide spread in times to implement repairs.

Another important reliability study for submarine cables is the study that was conducted for NorNed cable HVDC project [18]. The study reports the following figures for the submarine section of the cable system:

1) For water depths < 100m:
   - Internal failure frequency: 0.0066 failures/100km/year
   - External failure frequency: 0.0209 failures/100km/year
   - Total failure frequency: 0.0275 failures/100 km/year
2) For water depths > 100m:
   - Internal failure frequency: 0.0066 failures/100km/year
   - External failure frequency: 0.0005 failures/100km/year
   - Total failure frequency: 0.0071 failures/100 km/year

Please note that the above figures were estimated for a specific cable system (specific design and installation), and they cannot be generalized for other systems, in addition to the fact that each pole (bipole) failure will require the loss of two cables (three cables).

The NorNed study also reports the following figures for average repair times:

- For water depths <100 m the total outage time is 39 days or 936 hours
- For water depths >100 m the total outage time is 53 days or 1272 hours

As seen in the above results, it seems that the average submarine cable failure rate that was used in the previous Nalcor study for the LIL [5] is close to the above estimates for NorNed cable HVDC project with water depths > 100 m. However, as stated by both CIGRE and NorNed reports, submarine cable failures are mainly caused by external events. Therefore, given that the LIL cables will be installed on a low hazard path, will be well protected and properly handled during the installation, failure rates that are lower than the above numbers may be used for the LIL submarine cables.

The average submarine cable repair time that was used in the previous Nalcor study is significantly higher than the above figures because the risks associated with cable failures were considered. The total repair times for submarine cables are highly affected by availability of a repair vessel and accessibility of the site. Therefore, average repair times for an inaccessible cable system may be longer than the above average repair times.

6. Reliability Analysis

The adequacy of Newfoundland and Labrador Hydro's Interconnected Island System generation and transmission equipment under critical N-1 and N-2 contingencies was evaluated on a probabilistic basis in this study. A particular focus was to evaluate the impact of the insertion of the Labrador Island Link HVDC system and retirement of the Holyrood oil-fired thermal generation units in the Avalon Peninsula on the reliability of the system. A comparison was made between Pre-HVDC and Post-HVDC systems in terms of expected unserved energy to loads due to transmission and generation outages and risk of thermal overloading of critical transmission lines due to future load growth.

PSS®E was used to perform the contingency and reliability analysis. Expected unserved energy (EUE) was calculated for each contingency by manually applying any corrective actions, such as generation re-dispatch or load shedding[1], required to maintain system branch flows and bus voltages within Newfoundland and Labrador Hydro's Transmission Planning Criteria. Engineering judgement was exercised in order to minimize the amount of unserved load for each contingency.

6.1. Contingency Analysis

6.1.1. Pre-HVDC Case

The Pre-HVDC case provided by Nalcor is the peak case for 2017 which occurs during winter. This section describes single and double contingencies applied to the transmission system and generation units at Holyrood Thermal Generating Station for Pre-HVDC case. The analysis on the transmission system was performed on 230 kV lines. The single contingencies include the outage of every 230 kV line in the system as illustrated in Appendix B-Table 24; however, only ones associated with corrective actions are specified in Table 13.

For the purpose of contingency analysis, the subsystem and monitored elements were defined to be as follows:

- "Newfoundland" subsystem: It includes all the buses in area 108 with voltages of 66 kV and higher.
- Monitored elements include:

[1] Load shedding in this analysis does not reflect system responses to transient events such as underfrequency load shedding. Rather, the focus of this analysis relates to the system's ability to serve load and meet capacity requirements during sustained outages to transmission system elements.

- All the buses in the Newfoundland subsystem: buses were monitored to be in the range of 0.9 and 1.1 pu.
- All the branches in the Newfoundland subsystem: branches were monitored for any thermal overload.
- Since the Pre-HVDC case is the peak case for winter, the thermal loadings of the lines were compared against Rate C which is used for 0^{o} C ambient.
- Each contingency was implemented to the base case to ensure that the changes to the system were made as planned and the post contingency case met the defined planning criteria.

The following factors have been considered when determining corrective actions for each contingency:

- The corrective actions are specified so that they lead to minimum unserved load where possible.
- The lines loading and voltage profile align with Hydro criteria as specified in section 2.4.
- The minimum generation output for each unit at Bay d'Espoir not to be less than 60 MW.
- The generation output of every single generation not to exceed the maximum generation capacity value.

For (N-1) contingency analysis of Holyrood units, only the outage of G1 was considered because this unit is one of the two largest units in the station (G1 and G2 are both 170 MW units). The corrective actions associated with some of the (N-1) contingencies for Pre-HVDC case are summarized in Table 13. Meanwhile for (N-2) contingencies, only those combinations which have the most effect on delivering power to the loads in the Avalon Peninsula area were considered. For the Holyrood units, the outage of G1 and G2 was considered because it represented the worst case scenario compared to other combinations. The (N-2) contingencies as well as suggested corrective actions for each of them are shown in Table 14.

Table 13: (N-1) Contingencies for Pre-HVDC case

Contingency	Corrective Action
Holyrood unit G1 Unit Outage	1- Dispatching Hardwoods gas turbine at 50 MW 2- Dispatching Stephenville gas turbine to 50 MW 3- Dispatching Holyrood combustion turbine from 100 MW to 120 MW. 4- Dispatching NP Greenhill gas turbine at 20 MW 5- Dispatching NP Wesleyville gas turbine at 10 MW
TL218 Outage	1- Dispatching Hardwoods gas turbine at 50 MW 2- Decreasing generation at Holyrood combustion turbine from 100 MW to 50 MW.
TL242 Outage	1- Shed 57 MW from St John's area 2- Dispatching Hardwoods gas turbine at 50 MW 3- Decreasing generation at Holyrood combustion turbine from 100 MW to 0 MW.
TL208 Outage	1- 75.3 MW of load shed at Vale Inco Substation. 2-Unit G6 (Bay d'Espoir) is taken out of service.
TL207 Outage	1- Dispatching Hardwoods gas turbine at 50 MW 2- Switching the capacitor bank at Come By Chance Terminal Station from 153.4 to 115.05 Mvar 3- Disconnecting G6 (Bay d'Espoir) .
TL202 Outage	1- Dispatching Hardwoods gas turbine at 50 MW 2- Dispatching Holyrood combustion turbine from 100 MW to 120 MW. 3- Dispatching NP Greenhill gas turbine at 20 MW 4- Dispatching NP Wesleyville gas turbine at 10 MW 5- Dispatching Bay d'Espoir G7 output from 154 MW to 110 MW 6- Unit G6 (Bay d'Espoir) is taken out of service
TL206 Outage	same as TL202
TL234 Outage	1- Dispatching Hardwoods gas turbine at 50 MW 2- Dispatching Holyrood combustion turbine from 100 MW to 120 MW
TL235 Outage	1- Dispatching NP Greenhill gas turbine at 20 MW 2- Dispatching NP Wesleyville gas turbine at 10 MW 3- Generation outage at Nalcor Exploits facility. 4- Switched shunt at Greenhill is set out of service to mitigate the overvoltage at the same bus
TL248 Outage	Dispatching generation at Hinds Lake from 75 MW to 50 MW
TL209 Outage	Unit G6 (Bay d'Espoir) is taken out of service
TL247 Outage	1- Dispatching Stephenville gas turbine at 50 MW 2- Commencing diesel generation at Hawke's Bay (Bus 195033) at 5 MW 3- Commencing diesel generation at St. Anthony (Bus 195032) at 8.3 MW 4- Dispatching NP Greenhill gas turbine at 20 MW 5- Dispatching NP Wesleyville gas turbine at 10 MW 6- Switched shunt at Greenhill is taken out of service

Table 14: (N-2) transmission and Combined Holyrood Units Contingencies for Pre-HVDC case

Contingency	Corrective Action
Holyrood Units G1 & G2 Outages	1- Shed 198 MW of load 2- Dispatching Hardwoods gas turbine at 50 MW 3- Dispatching at Holyrood combustion turbine from 100 MW to 120 MW 4- Dispatching Greenhill NP gas turbine at 20 MW
Holyrood Units G1 & G2 & G3 Outages	1- Shed 350 MW of load 2- Dispatching Hardwoods gas turbine at 50 MW 3- Dispatching at Holyrood combustion turbine from 100 MW to 120 MW 4- Dispatching Greenhill NP gas turbine at 20 MW
TL 202 & TL206 Outage	1- Shed 352 MW of load 2- Dispatching Hardwoods gas turbine at 50 MW 3- Dispatching at Holyrood combustion turbine from 100 MW to 120 MW 4- Bay d'Espoir units G1 to G6 are taken out of service 5- Switched shunt at Oxen Pond Terminal Station is taken out of service
TL 203 & TL237 Outage	1- Shed 240 MW of load 2- Dispatching Hardwoods gas turbine at 50 MW 3- Dispatching unit G7 at Bay d'Espoir from 154 MW to 140 MW 4- Bay d'Espoir units G1 to G6 are taken out of service 5- Switched shunt at Come by Chance Terminal Station is taken out of service 6- Switched shunt at Hardwoods Terminal Station is taken out of service 7- Switched shunt at Oxen Pond Terminal Station is taken out of service
TL 203 & TL207 Outage	1- Shed 266 MW of load 2- Dispatching Hardwoods gas turbine at 50 MW 3- Dispatching unit G7 at Bay d'Espoir from from 154 MW to 110 MW 4- Bay d'Espoir units G1 to G6 are taken out of service 5- Dispatching generation at New Chelsea plant to 4.3 MW 6- Dispatching generation at Horse Chops plant to 8.1 MW 7- Dispatching generation at Cape Broyle plant to 6.35 MW 8- Switched shunt at Come by Chance Terminal Station is taken out of service 9- Switched shunt at Hardwoods Terminal Station is taken out of service 10- Switched shunt at Oxen Pond Terminal Station is taken out of service
TL 236 & TL242 Outage	1- Shed 140 MW of load 2- Dispatching Hardwoods gas turbine at 50 MW 3- Dispatching generation at Holyrood combustion turbine from 100 MW to 0 MW
TL 218 & TL242 Outage	1- Shed 270 MW of Load 2- Bay d'Espoir units G3 to G6 are taken out of service
TL 201 & TL242 Outage	1- Shed 191 MW of load 2- Bay d'Espoir units G3 to G6 are taken out of service 3- Dispatching Hardwoods gas turbine at 50 MW 4- Switching the capacitor bank at Come By Chance Terminal Station from 153.4 to 38.35 Mvars
TL 218 & TL236 Outage	1- Shed 150 MW of load 2- Bay d'Espoir unit G6 is taken out of service 3- Dispatching Bay d'Espoir G7 from 154 MW to 145 MW 4- Taking switched shunt, at Greenhill , out of service

6.1.2. Post-HVDC Case

As with the Pre-HVDC case, the Post-HVDC case represents a peak winter power flow scenario. Therefore, Rate C was used for determining thermal overloads on lines. The single contingencies for the transmission system that were studied are the outages of each 230 kV line shown in Appendix B - Table 24 and Table 25. List of studied N-1and N-2 contingencies requiring corrective actions are illustrated in Table 15 and Table 16, respectively.

Table 15: N-1 Contingencies for Post-HVDC case

Contingency	Corrective Action
TL208 Outage	Dispatching LIL power transfer level from 900 MW to 750 MW, and 80 MW of load shed
TL235 Outage	Bay d'Espoir unit G5 is brought into service
TL248 Outage	1- Dispatching generation at Hinds Lake from 75 MW to 30 MW 2- Bay d'Espoir unit G5 is brought into service
TL209 Outage	Bay d'Espoir unit G4 is taken out of service
TL247 Outage	Bay d'Espoir units G5 and G6 are brought into service

Table 16: Double Contingencies for Post-HVDC case

Contingency	Corrective Action
TL265 & Holyrood CT Outage	1- Dispatching Hardwoods gas turbine at 50 MW 2- Dispatching Bay d'Espoir units G7 to 130 MW each
TL242 & TL266 Outage	1- Shed 178 MW of load 2- Dispatching Bay d'Espoir units G7 to 120 MW each 3- Dispatching Hardwoods gas turbine at 50 MW 4- Dispatching HVDC power transfer level from 900 MW to 700 MW
LIL Bipole Outage	1- Dispatching Bay d'Espoir units G5, and G6 to 76 MW each 2- Dispatching Hardwoods gas turbine at 50 MW 3- Dispatching generation at Holyrood combustion turbine from 0 MW to 120 MW 4- Dispatching Stephenville gas turbine to 50 MW 5- Importing 300 MW through Maritime Link 6- Dispatching generation at St. Anthony to 8.3 MW 7- Dispatching generation at Greenhill to 20 MW 8- Dispatching generation at Wesleyville to 10 MW 9- Dispatching generation at Hawke's Bay to 5 MW 10- Dispatching generation at Cat Arm from 127 MW to 134 MW 11- Dispatching unit G9 at Grand Falls from 27 MW to 30 MW 12- Dispatching generation at Dear Lake from 80 MW to 81.1 MW 13- Dispatching generation at Rose Blanche from 5.7 MW to 6 MW 14- Dispatching generation at Lookout Brook from 5.5 MW to 5.8 MW 15- Dispatching generation at Grand Bay from 0 to 6.5 MW 16- Dispatching generation at Rattle Brook from 13.5 MW to 14.8 MW 17- Dispatching generation at New Chelsea from 3.4 MW to 4.3 MW 18- Dispatching Bay d'Espoir unit G7 from 154 MW to 154.4 MW 19- Dispatching generation at Lockston from 2.5 MW to 3.0 MW 20- Dispatching generation at Port Union from 0.2 MW to 0.5 MW 21- Changing the switched shunt at Come by Chance from 76.7 Mvar to 153.4 Mvar 22- Bringing synchronous condenser at Soldiers Pond into service
TL265 & TL268 Outage	1- Dispatching Hardwoods gas turbine at 50 MW 2- Dispatching Bay d'Espoir units G7 to 130 MW each 3- Bringing synchronous condenser at Soldiers Pond into service
TL218 & TL236 Outage	1- Shed 150 MW of load 2- Dispatching Bay d'Espoir units G7 to 145 MW each 3- Bringing synchronous condenser at Soldiers Pond into service 4- Bay d'Espoir units G3 & G4 are taken out of service

6.2. Probabilistic Reliability Analysis

Probabilistic reliability analysis was performed in PSS®E on the contingencies described above. The failure rates and outage durations for each component or pair of components shown in section 4.3, along the results of the contingency analysis were used to calculate expected unserved energy (EUE) in the IIS.

6.2.1. Holyrood Thermal Unit Outages

Total expected unserved energy (EUE) for the Pre-HVDC 2017 Winter Peak case based on PSS®E probabilistic reliability analysis of double Holyrood Thermal Unit outages and all three units combined is shown in Table 17.

Table 17: Expected Unserved Energy for Holyrood Thermal Unit Outages

Contingency	EUE based on CEA reliability data (GWh/year)	EUE based on Hydro reliability data (GWh/year)	EUE based on Hydro sensitivity reliability data (GWh/year)
G1 and G2	5.3	16	23.5
G1, G2, and G3	0.5	2.8	4.9

Note that this analysis is based on the simple probabilities of outages 1, 2, and 3 units. It does not take into account all the possible system states that include these contingencies. These contingencies were selected for analysis because it was believed they would demonstrate the dependency of the Avalon Peninsula loads on the availability of the Holyrood units. The results do not show a complete calculation of expected loss of energy due to all possible combinations of Holyrood unit outages and outages of other system components. The outages of generating units other than the Holyrood thermal units do not contribute significantly to the unreliability of the system. Typically, there is enough generation reserve in the system to handle outages of other units, and hydro units typically have a higher reliability than thermal units. The main reason for the capacity shortfall due to loss of Holyrood units is lack of voltage support in the Avalon Peninsula, which leads to consequent voltage instability. All other system components are in service during the outages of the Holyrood units, and there is no other system state in which the impact of a Holyrood unit is lessened. Therefore, the EUE values calculated are considered representative of the impact of thermal unit outages, and are useful for comparison to the reliability of the Post-HVDC system.

6.2.2. Hydro Unit Outages

The two largest hydro units in the IIS, Bay d'Espoir unit 7 and Upper Salmon, have a combined capacity of 238 MW. Both units are dispatched at full capacity in both the Pre-HVDC and Post-HVDC cases.

For the Pre-HVDC case, it was found that there is sufficient reserve generation in the system to compensate for the simultaneous loss of both units with no loss of load. Compensation for the loss of both hydro units would require the full output of the combustion turbines at Holyrood, Hardwoods and Stephenville, as well as most of the available capacity from units owned by Newfoundland Power. However, the probability of a simultaneous outage of both hydro units, based on the CEA 2008-2012 DAFOR for all hydro units, is approximately 0.13%, which is equivalent to 12 hrs/yr unavailability.

In the Post-HVDC case, there are multiple options for compensating for the loss of the two largest hydro units, which include dispatch of the out-of-service hydro units at Bay d'Espoir or the combustion turbines.

6.2.3. Transmission Line Outages

6.2.3.1. Pre-HVDC Case

Total expected unserved energy (EUE) for the Pre-HVDC 2017 Winter Peak case based on PSS®E probabilistic reliability analysis of single and double transmission line contingencies was 100.8 MWh/year. Outage of either TL242 or TL208 has contributed mostly to this total value.

It should be noted that TL208 is a radial transmission line that supplies industrial customers Vale and Praxair in Long Harbour. These customers elected to be supplied by a single radial transmission line.

Outages to TL242 result in the overloading of TL218 under peak loading conditions. This overload will be eliminated by the reconfigurations of the transmission lines on the Avalon Peninsula following the establishment of Soldiers Pond Terminal Station and the thermal uprating of TL266. These upgrades are scheduled to be completed in 2017.

EUE for the contingencies that result in unserved load is shown in Table 18.

Table 18: Expected Unserved Energy for AC Transmission Line Contingencies in Pre-HVDC Case

Contingency	Expected Unserved Energy (MWh/year)
TL208	41.43
TL242	58.03
TL201-TL242	0.07
TL203-TL237	0.08
TL206-TL202	1.13
TL203-TL207	0.01
TL218-TL236	0.01
TL218-TL242	0.04
TL236-TL242	0
Total	**100.8**

6.2.3.2. Post-HVDC Case

Total expected unserved energy (EUE) for the Post-HVDC 2018 Winter Peak case based on PSS®E probabilistic reliability analysis of single and double transmission line contingencies was 41.94 MWh/year. Similar to Pre-HVDC case, outage of TL208 has contributed mostly to this total value. As discussed above, the contribution of TL242 outage to total EUE is eliminated by transmission system upgrades.

EUE for the contingencies resulting in unserved load is shown in Table 19.

Table 19: Expected Unserved Energy for AC Transmission Line Contingencies in Post-HVDC Case

Contingency	Expected Unserved Energy (MWh/year)
TL208	41.92
TL242-TL266	0.01
TL218-TL236	0.01
Total	41.94

The outage of LIL HVDC bipole with ML HVDC bipole in service will not result in unserved load. However, there are recorded undervoltages down to 0.894 pu for a couple of 138 kV buses, and 0.891 pu for a single 66 kV bus. These undervoltage conditions are corrected by bringing the third Soldiers Pond synchronous condenser online and through tap changer action of power transformers.

On the other hand, if LIL is in service while ML is not considered in the Post-HVDC case scenario, the outage of LIL will result in unserved energy. Based on Nalcor's projected reliability parameters provided in Section 5.2.1.5, the anticipated EUE will be 2.72 GWh/year.

This analysis highlights ML impact on overall system stability under Post-HVDC conditions.

An additional analysis was performed for the Post-HVDC case to look at the line loading considering future load growth. For (N-1) contingencies, the results show significant loading on TL242 in the event of losing TL266 and/or with future load increase in the area fed from Hardwoods and Oxen Pond Terminal Station. The percentage of TL242 loading for the loss of TL266 is 89.8%. Also, for loss of TL236, TL218 loading would be equal to 81.5%. In addition, an outage of LIL HVDC bipole loads TL202 and TL206 up to 82%. These future loading conditions will be monitored and addressed, as required, as part of Hydro's routine transmission planning procedures.

6.2.4. Holyrood Unit Outages versus Load Duration Curve

As shown above, in the 2017 Pre-HVDC peak winter case, corrective actions were required for double outages of Holyrood generation units G1 and G2 (or combined outage of G1, G2 and G3 units). Corrective actions result in 198 MW of unserved load on the Avalon Peninsula (or 350.33 MW for the combined outage of G1, G2, and G3 units). The results of the probabilistic reliability analysis showed exceptionally large EUE values for this contingency. However, the EUE values were calculated under peak loading conditions and are stated as a rate of loss of load, i.e. MWh per year. Therefore they must be qualified through comparison to the actual loading characteristics of the system in order to evaluate their expected impact. This evaluation was performed using the following methodology:

1. Scale down the variable loads in the IIS, i.e. all loads excluding Holyrood station service and industrial loads, by increments of 5%. The swing bus units at Bay d'Espoir were allowed to decrease their output as required for power flow solution.
2. Perform contingency analysis on outages of Holyrood units with corrective actions, but without shedding any loads.
3. Note the minimum amount of load scaling required, i.e. the maximum system load allowed, for the contingency to meet bus voltage and branch flow criteria.
4. Match the amount of unserved load to the load duration curve to estimate the percent time during a year that there would be an exposure to unserved energy.

With the IIS variable load scaled down by 15%, the load in the Avalon Peninsula was reduced by approximately 127 MW. Contingency analysis was then performed for a double outage of Holyrood units G1 and G2. The following corrective actions were required for this contingency:

1. Increase Generation at Holyrood Combustion Turbine (Bus 195014) from 100 MW to 120 MW.
1. Setting Hardwoods Gas Turbine (Bus 195030) in generation mode at 50 MW.
2. Shed 20 MW of load at Kenmount Substation (Bus 196565).

With the IIS variable load scaled down by 20%, the load in the Avalon Peninsula was reduced by approximately 167 MW. Contingency analysis was then performed for a double outage of Holyrood units G1 and G2. The following corrective actions were required for this contingency:

1. Increase Generation at Holyrood Combustion Turbine (Bus 195014) from 100 MW to 120 MW.
2. Setting Hardwoods Gas Turbine (Bus 195030) in generation mode at 50 MW.
3. Increase the tap setting on the 69kV/25kV transformer at St. Anthony Diesel Plant Terminal Station to reduce voltages on the low voltage side.

The total IIS load and the corresponding percent of peak load for each 5% increment of variable IIS unserved load is shown in Table 20. Also shown in this table is the expected time during the year that the system demand would be such that there is an exposure for unserved load, based on the load duration curve.

Based on this analysis, unserved load for double outages of Holyrood units G1 and G2 would only be expected to be required for 12% of the year, at most. In case of the combined G1, G2 and G3 outage, unserved load would be expected to be required for 18% of the year

Similar approach was considered for the Post-HVDC case with LIL HVDC bipole outage when ML is not considered in the case. Unserved load for this scenario would be only expected for 9 % of the year at most.

Table 20: Unserved Load vs Load Duration Curve

Variable IIS Unserved Load (%)	Total IIS Load (MW)	Percent of Peak Load (%)	Load Duration (% of year)
0%	1729.2	100%	0.03%
5%	1655.7	95.7%	0.6%
10%	1582.3	91.5%	2.5%
15%	1508.9	87.3%	7%
20%	1435.5	83.0%	12%
25%	1362.0	78.8%	19%

7. Conclusion

This study presented a probabilistic reliability assessment comparison for the IIS under pre and post HVDC planned developments. The HVDC developments considered the addition of LIL and ML HVDC systems to the IIS with associated planned ac system upgrades/changes. It also considered the retirement of Holyrood thermal units under Post-HVDC conditions.

The availability characteristics of the generation and transmission equipment were based on historical performance data provided by Nalcor. Reliability Data from CEA was used to perform a sensitivity analysis for generator outages. The reliability characteristics of the Labrador Island Link and Maritime Link were discussed in detail and compared to industry statistics for pre and post HVDC conditions (both LIL and ML were considered).

An analysis of available outage data determined that:

- The line commutated converter outage data based on CIGRE data indicates an expected pole failure rate for a bipole HVDC system per terminal is approximately 1.9 failures per year with an average pole outage duration of approximately 19.8 hours. These values are comparable to the Nalcor provided values of 2.0 failures per year with an average pole outage duration of 21 hours used in previous studies.
- The voltage source converter outage data was used to determine an overall energy availability of a bipole system to equal approximately 97.3% not including the impacts of transmission line and bipole failures. This is consistent with the stated availability of Maritime Link at 95% to 97%.
- HVDC overhead line data was used to determine an average pole failure rate of 0.14/year/100 km with an average pole repair time of 36.4 hours per outage for the Labrador Island Link. In comparison, the values used by Nalcor in previous studies were 0.19 outages/year/100 km with a duration of 1.78 hours per outage. The Nalcor outage rate is more pessimistic than the values calculated here. However, the duration is much lower.
- Submarine cable reliability data is site and system specific. For water depths greater than 100 m the data suggests a total failure frequency of 0.0071 failures/100km/year with a total outage time of 53 days or 1272 hours. The Nalcor data provides an average pole failure

rate of 0.0022/year on 30 km of cable, or an equivalent of 0.0073 failures/100 km/year with an average pole repair time of 4163 hours (173 days). It is acknowledged that the repair time is dependent upon factors such as ship availability, weather and removal of cable protection. It is understood that Nalcor will be incorporating rock berms to protect the cable. Nalcor's use of a 4163 hour repair time may be reasonable considering the environment of the cable location.

- Analysis of 230 kV transmission line outages on the Island Interconnected System delivered a comparison between ac transmission system reliability in the Pre- and Post-HVDC cases. The expected unserved energy due to 230 kV transmission line contingencies in the Pre-HVDC case were calculated to equal 100.8 MWh/year. Of that total 41.43 MWh/year is attributed to the loss of TL208[2], and 58.03 MWh/year attributed to the loss of TL242. With approved transmission system upgrades, including the replacement of TL266, the expected unserved energy due to 230 kV transmission line contingencies in the Post-HVDC case is reduced to 41.94 MWh/year attributed to the loss of TL208. The analysis concludes that based on a probabilistic reliability assessment, the reliability of the 230 kV transmission system on the Island Interconnected System is improved in the Post-HVDC case compared to the Pre-HVDC case.
- While the reliability of the transmission network is improved, the EUE resulting from ac transmission line outages is not material to the comparison of Pre-HVDC and Post-HVDC cases. Rather, this comparison is fundamentally between the reliability of the Holyrood units and the HVDC transmission links, as summarized in Table 21 and Table 22.
- As presented in Table 22, The IIS would have a total expected EUE of 0.02 MWh/year. It is noted that without the ML, the EUE would increase by 2.72 GWh/year

Table 21: Summary of Expected Unserved Energy (MWh/year) and Probability of Unserved Load for Pre-HVDC Cases

Contingency	E.U.E based on CEA reliability data (GWh/year)	E.U.E based on Hydro reliability data (GWh/year)	E.U.E based on Hydro sensitivity reliability data (GWh/year)	Probability of Sustained Unserved Load (%)
Holyrood Units G1 and G2	5.3	16	23.5	12%
Holyrood Units G1, G2 , and G3	0.5	2.8	4.9	18%

Table 22: Summary of Expected Unserved Energy (MWh/year) and Probability of Unserved Load for Post-HVDC Cases

Contingency	E.U.E (GWh/year)	Probability of Sustained Unserved load (%)
LIL HVDC Bipole (with ML)	0.00002	0%
LIL HVDC Bipole (without ML)	2.72	9%

[2] TL208 is a radial 230 kV transmission line supplying only industrial customers Vale and Praxair in Long Harbour. These customers elected to be supplied by a single radial transmission line.

8. References

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Appendix A
System Generation

Sources of generation in the IIS are summarized in Table 23. For the purposes this study, the difference between the capacity (P_{max} in the PSS®E cases) and the dispatch for the hydro and combustion turbine units was considered to be reserve available for unplanned outages of transmission and generation elements (contingencies).

Additional generating units are distributed throughout the IIS and are operated by independent entities such as Newfoundland Power and Corner Brook Pulp and Paper (Kruger). For the purposes of this study the undispatched capacities of these units were considered available as reserve for contingency conditions.

Table 23: Major Hydro Owned or Power Purchase Generating Units in Pre-HVDC and Post-HVDC Cases

Generating Unit	Type	Capacity (MW)	Dispatch Pre-HVDC (MW)	Reserve Pre-HVDC (MW)	Dispatch Post-HVDC (MW)	Reserve Post-HVDC (MW)
Bay d'Espoir 1	Hydro	76.5	65.4	11.1	67.7	8.8
Bay d'Espoir 2	Hydro	76.5	65.8	10.7	67.7	8.8
Bay d'Espoir 3	Hydro	76.5	65.8	10.7	67.7	8.8
Bay d'Espoir 4	Hydro	76.5	65.8	10.7	67.7	8.8
Bay d'Espoir 5	Hydro	76.5	65.8	10.7	0	76.5
Bay d'Espoir 6	Hydro	76.5	65.8	10.7	0	76.5
Bay d'Espoir 7	Hydro	154.4	154	0.4	154	0.4
Cat Arm 1	Hydro	67	63.5	3.5	63.5	3.5
Cat Arm 2	Hydro	67	63.5	3.5	63.5	3.5
Upper Salmon	Hydro	84	84	0	84	0
Hinds Lake	Hydro	75	75	0	75	0
Granite Canal	Hydro	40	40	0	40	0
Paradise River	Hydro	8	8.0	0	8	0
Expoits River 4	Hydro	24	24	0	24	0
Expoits River 5	Hydro	4.5	4.5	0	4.5	0
Expoits River 6	Hydro	4.5	4.5	0	4.5	0
Expoits River 7	Hydro	4.5	4.5	0	4.5	0
Expoits River 8	Hydro	4.5	4.5	0	4.5	0
Expoits River 9	Hydro	30	27	3	27	3
Expoits River Bishop's Falls	Hydro	18	18	0	18	0
Holyrood 1	Thermal	170	170	0	Standby	0
Holyrood 2	Thermal	170	170	0	Standby	0
Holyrood 3	Thermal	150	150	0	Sync. Cond.	0
Holyrood CT	Combustion Turbine	120	100	20	0	120
Stephenville	Combustion Turbine	50	0	50	0	50
Hardwoods	Combustion Turbine	50	0	50	0	50

Appendix B
230 kV Transmission System

The 230 kV transmission system in the IIS in the Pre-HVDC 2017 base case consists of 25 transmission lines, as listed in Table 24. The lines listed in Table 24 have a total length of 1608km. The thermal ratings (MVA) for the lines shown below are used in Nalcor's Winter Cases where an ambient temperature of 0^{o}C is assumed.

Table 24: 230 kV Transmission Lines in Pre-HVDC and Post-HVDC Cases

Transmission Line	Terminal Station 1	Terminal Station 2	Length (km)	Winter Rating (MVA)
TL201*	Western Avalon	Hardwoods	80.678	322.2
TL202	Bay d'Espoir	Sunnyside	141.758	369.5
TL203	Sunnyside	Western Avalon	44.534	347.0
TL204	Bay d'Espoir	Stony Brook	105.021	469.6
TL205	Stony Brook	Buchans	83.937	322.2
TL206	Bay d'Espoir	Sunnyside	141.927	369.5
TL207	Sunnyside	Come By Chance	6.671	459.6
TL208	Western Avalon	Long Harbour	14.711	369.5
TL209	Bottom Brook	Stephenville	21.056	369.5
TL211	Massey Drive	Bottom Brook	55.680	322.2
TL217*	Western Avalon	Holyrood	76.663	459.6
TL218	Holyrood	Oxen Pond	37.294	369.5
TL228	Buchans	Massey Drive	84.770	290.0
TL231	Bay d'Espoir	Stony Brook	105.310	469.6
TL232	Stony Brook	Buchans	84.247	469.6
TL233	Buchans	Bottom Brook	135.847	369.5
TL234	Upper Salmon	Bay d'Espoir	51.538	469.6
TL235	Grand Falls Frequency Converter	Stony Brook	0.620	322.2
TL236	Hardwoods	Oxen Pond	10.338	459.6
TL237	Come By Chance	Western Avalon	44.950	459.6
TL238 (Out of Service)	Stephenville	Abitibi Consolidated - Stephenville Division	0.862	369.5
TL242*	Holyrood	Hardwoods	27.210	459.6
TL247	Cat Arm	Deer Lake	122.909	466.6
TL248	Deer Lake	Massey Drive	55.119	466.6
TL263	Granite Canal	Upper Salmon	74.761	369.5

*These lines are reconfigured in the Post-HVDC case.

The 230 kV transmission system in the IIS Post-HVDC 2018 base case consists of the transmission lines listed in Table 24 as well as the lines listed in Table 25.

Table 25: Reconfigured and Additional 230 kV Transmission Lines in Post-HVDC Case

Transmission Line	Terminal Station 1	Terminal Station 2	Length (km)	Winter Rating (MVA)
TL201	Western Avalon	Soldiers Pond	65	322.2
TL217	Western Avalon	Soldiers Pond	65	454
TL242	Soldiers Pond	Hardwoods	16	460
TL265	Soldiers Pond	Holyrood	11	460
TL266	Soldiers Pond	Hardwoods	15	460
TL267	Bay d'Espoir	Western Avalon	186	454
TL268	Soldiers Pond	Holyrood	11	454
TL269	Granite Canal	Bottom Brook	180	460

Appendix C
Calculation of Reliability Statistics

1. Definitions

Some definitions that are relevant to this study are given below.

Availability and Unavailability: The availability of a system or individual component (such as a transmission line or generator) is the fraction of total desired operating time that the component is expected to be operating. In other words, it is the probability that the component will be able to operate at any given point in the future. The availability is numerically expressed as:

$$A = \frac{\mathrm{MTTF}}{\mathrm{MTTF} + \mathrm{MTTR}} = \frac{\mu}{\lambda + \mu} = \frac{m}{m + r}$$

The unavailability of a system is the fraction of total desired operating time that the system is not available. In other words, it is the probability that the component will not be able to operate at any given point in the future. The unavailability is numerically expressed as:

$$U = \frac{\mathrm{MTTR}}{\mathrm{MTTF} + \mathrm{MTTR}} = \frac{\lambda}{\lambda + \mu} = \frac{r}{m + r} = 1 - A$$

(Note that A and U can also be expressed in hours per year by multiplying them by 8760 hours.)

Where:

λ is the average failure rate [in failures per year]

μ is the average repair rate [in repairs per year]

m is the Mean Time to Failure (MTTF) [in hours or years]

$$m = \frac{1}{\lambda}$$

r is the Mean Time to Repair (MTTR), or average outage duration [in hours or years]

$$r = \frac{1}{\mu}$$

Outage Frequency: The outage frequency is the expected number of outages of a compenent in a given time frame given its average failure rate and average outage duration. The outage frequency is numerically expressed as:

$$F = \frac{\lambda}{\lambda + \mu} * \mu = \frac{U}{r}$$

(Note that if U is expressed in hours per year then F will be expressed in occurrences per year.)

Expected Unserved Energy (EUE) is the total unsupplied energy to loads in a given time frame due to system interruptions (component outages).

$$\mathrm{EUE} = \sum L_i U_i$$

Where Li is the load curtailed or unavailable power (MW) for the ith outage and Ui is the unavailable hours for the ith outage.

2. Frequency and Duration Method

The frequency and duration method was used to calculate the probabilities of outages of multiple components [23]. All N-2 outages in this study were considered to be the result of independent outages of two components. Therefore, the method for calculating equivalent forced outage rates and equivalent outage durations for parallel systems was used, as described below.

The following parameters are required to pursue this method.

$\lambda_1, \lambda_2 \ldots \lambda_i$ = component failure rates in [failures/year]

$r_1, r_2 \ldots r_i$ = component average outage durations [in years]

The equivalent forced outage rate for two components is:

$$\lambda_e = \frac{\lambda_1 \lambda_2 (r_1 + r_2)}{(1 + \lambda_1 r_1 + \lambda_2 r_2)}$$

An approximate equation for equivalent forced outage rate when $\lambda_i * r_i << 1$ is:

$$\lambda_e = \lambda_1 \lambda_2 (r_1 + r_2)$$

The expected outage duration for two components is:

$$r_e = \frac{r_1 r_2}{(r_1 + r_2)}$$

3. Generator Reliability

3.1. CEA-ERIS

Some terms related to generator reliability defined by the Canadian Electricity Association Equipment Reliability Information System (CEA-ERIS) [22] are given below.

Definition of States:

Operating State (11): the generating unit is spinning and is capable of operating at Maximum Continuous Rating (MCR) under normal operating procedures.

Operating under a Forced Derating (12): the generating unit is spinning and/or synchronized with system but not capable of carrying its MCR due to a forced derating being in effect.

Operating under a Scheduled Derating (13): the generating unit is synchronized with system but not capable of carrying its MCR due to a scheduled derating being in effect.

Available But Not Operating – Forced Derating State (15): the generating can deliver only part of its MCR due to a forced derating but is not being operated to supply system load.

Forced Outage State (21): the generating unit has a forced outage which requires that it be removed from service.

Forced Extension of a Maintenance Outage State (22): the generating unit has an outage resulting from a condition discovered during a maintenance outage which has forced the extension of the maintenance outage.

Forced Extension of a Planned Outage State (23): the generating unit has an outage resulting from a condition discovered during a planned outage which has forced the extension of the planned outage.

The Concept of Adjusted Time:

To take into account the derated levels of a generating unit, the operating time at these levels is transformed into an equivalent outage time. Thus, the time of X% of MCR, called O(FD)x is converted to an equivalent outage time, called O(FD)adjusted according to the transformation.

$$O(FD)adj = \left(\frac{100 - X}{100}\right) * O(FD)x$$

Table 32 shows the symbols used to denote the number hours spent in each of the above defined states.

Table 26: Symbols Used to Denote Hours Spent in Various States

State	State Number	Symbol
Operating	11	O
Operating under a Forced Derating	12	O(FD)
Operating under a Forced Derating – Adjusted		O(FD)adj
Operating under a Scheduled Derating	13	O(SD)
Available But Not Operating – Forced Derating State	15	ABNO(FD)
Forced Outage State	21	FO
Forced Extension of a Maintenance Outage State	22	FEMO
Forced Extension of a Planned Outage State	23	FEPO

Fail Rate: the Failure Rate. It is the rate at which a generating unit encounters a forced outage. It is computed by dividing the Number of Transitions from an Operating State (11, 12, 13) to a Forced Outage (21) by the Total Operating Time 8760.

Mean F.O.D (H): the mean duration of a forced outage. It is computed by dividing the total Forced Outage Time by the Number of Forced Outages.

3.1.1.1. IEEE Standard 762

IEEE Standard 762 [26] definitions related to generator reliability statistics are given below.

Class 0 unplanned outage (starting failure) results from the unsuccessful attempt to place the unit in service.

Class 1 unplanned outage (immediate) requires immediate removal from the existing state. It can be initiated from the in-service state, reserve shutdown state, or the planned outage state.

Class 2 unplanned outage (delayed) does not require immediate removal from the in-service state, but requires removal within 6 h.

Class 3 unplanned outage (postponed) can be postponed beyond 6 h, but requires that a unit be removed from the in-service state before the next weekend.

Service Hours (SH) is the number of hours a unit was in the in-service state.

Forced outage hours (FOH) is the number of hours a unit was in a Class 0, 1, 2 or 3 unplanned outage state.

Forced Outage Rate (FOR) is a measure of the probability that a generating unit will not be available due to forced outages.

$$FOR = \left(\frac{FOH}{FOH + SH}\right) * 100$$

Where:

$$FOH = FO + FEMO + FEPO$$

$$SH = O + O(FD) + O(SD)$$

Derating Adjusted Forced Outage Rate (DAFOR) is the ratio of equivalent forced outage time to the sum of equivalent forced outage time plus total equivalent operating time.

$$DAFOR = \left(\frac{FO + FEMO + FEPO + O(FD)adj + ABNO(FD)adj}{FO + FEMO + FEPO + O(FD)adj + ABNO(FD)adj + O + O(FD) + O(SD)}\right) * 100$$

Demand Factor (f) is used to estimate forced outage hours overlapping the period of demand for the unit to operate.

$$f = \left(\frac{\left(\frac{1}{r} + \frac{1}{T}\right)}{\left(\frac{1}{r} + \frac{1}{T} + \frac{1}{D}\right)}\right)$$

Where:

$$r = Average\ forced\ outage\ duration = \frac{FOH}{Number\ of\ forced\ outages}$$

$$T = Average\ reserve\ shutdown\ time = \frac{Reserve\ shutdown\ hours}{number\ of\ reserve\ shutdowns}$$

$$D = Average\ demand\ time\ (duty\ cycle\ time) = \frac{SH}{Number\ of\ demand\ occurances}$$

Utilization forced outage probability (UFOP) is a measure of the probability that a generating unit will not be available due to forced outages when there is demand on the unit to operate.

$$UFOP = \left(\frac{f * (FO + FEMO + FEPO)}{f * (FO + FEMO + FEPO) + O + O(FD) + O(SD)}\right)$$