newfoundland labrador
hydro
a nalcor energy company

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November 16, 2018

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - the Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - Reliability and Resource Adequacy Study – November 2018

Please find enclosed one original plus eight copies of Newfoundland and Labrador Hydro's ("Hydro") Reliability and Supply Adequacy Study ("Study").

Significant system changes have occurred since Hydro's last assessment of long-term resource adequacy in 2012, requiring adaptation of Hydro's planning tools and processes. The enclosed Study details the evolution of Hydro's processes and tools, and addresses the company's long-term approach to providing continued least-cost, reliable service for its customers. The analysis focuses on Hydro's proposed planning criteria and its ability to meet customer and system requirements reliably over a ten-year planning horizon (2019 to 2028).

In contemplation of interconnection to the North American grid, Hydro undertook a full review of its planning criteria. This review considered Hydro's past practices, other utility practices, and the intention to voluntarily comply with the North American Electric Reliability Corporation reliability standards and Northeast Power Coordinating Council operational requirements.

This Study is comprised of three volumes. Volume I outlines Hydro's Study methodology and proposed planning criteria. Volume II provides an in-depth view of near-term resource reliability. Volume III provides the long-term resource planning considerations, resource options available to meet the criteria proposed in Volume I, and Hydro's proposed action plan. Additionally, a Summary Document is included to highlight, in brief, the key considerations of the Study.

To complement the technical efforts which form the foundation of this analysis, stakeholder consultations, focused on reliability and resource planning, were undertaken to inform the process. Consultations were conducted with Newfoundland Power, Hydro's Industrial Customers, the Consumer Advocate, and provincial electricity customers.

Based on the completed Study, Hydro recommends modifications to both the probabilistic and deterministic capacity planning criteria. Hydro also proposes to extend the system energy planning criteria to the entire Newfoundland and Labrador Interconnected System.

While an action plan is proposed, Hydro believes continue consultation and discussion with the Newfoundland and Labrador Board of Commissioners of Public Utilities ("Board") and other stakeholders will ultimately assist in the determination of the most appropriate investment for customers.

Hydro intends to file annual updates to Volumes II and III of this Study. By conducting such analysis each year, Hydro will be able to provide both near and long-term system plans and advise on the impact of changes in key inputs in a timely manner. As such a filing will be a more comprehensive system report, and include a near-term reliability report which is a hybrid of the methodology used in prior near-term generation filings, paired with assessment guidelines defined by North American Electric Reliability Corporation to perform high-quality probabilistic resource adequacy assessments, Hydro proposes that it replace the semi-annual filing of the Near-Term Generation Adequacy report.

Hydro welcomes feedback from all stakeholders on the findings of this Study. Hydro further proposes that a process be put in place to facilitate discussion and engagement on the proposed planning criteria.

Should you have any questions or comments about any of the enclosed, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Regulatory Counsel
SAW/sk

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Danny Dumareque

ecc: Larry Bartlett – Teck Resources Ltd.
Roberta Frampton Benefiel – Grand Riverkeeper® Labrador
Denis Fleming- Cox & Palmer

Reliability and Resource Adequacy Study

List of Contents

The components of this Study include:

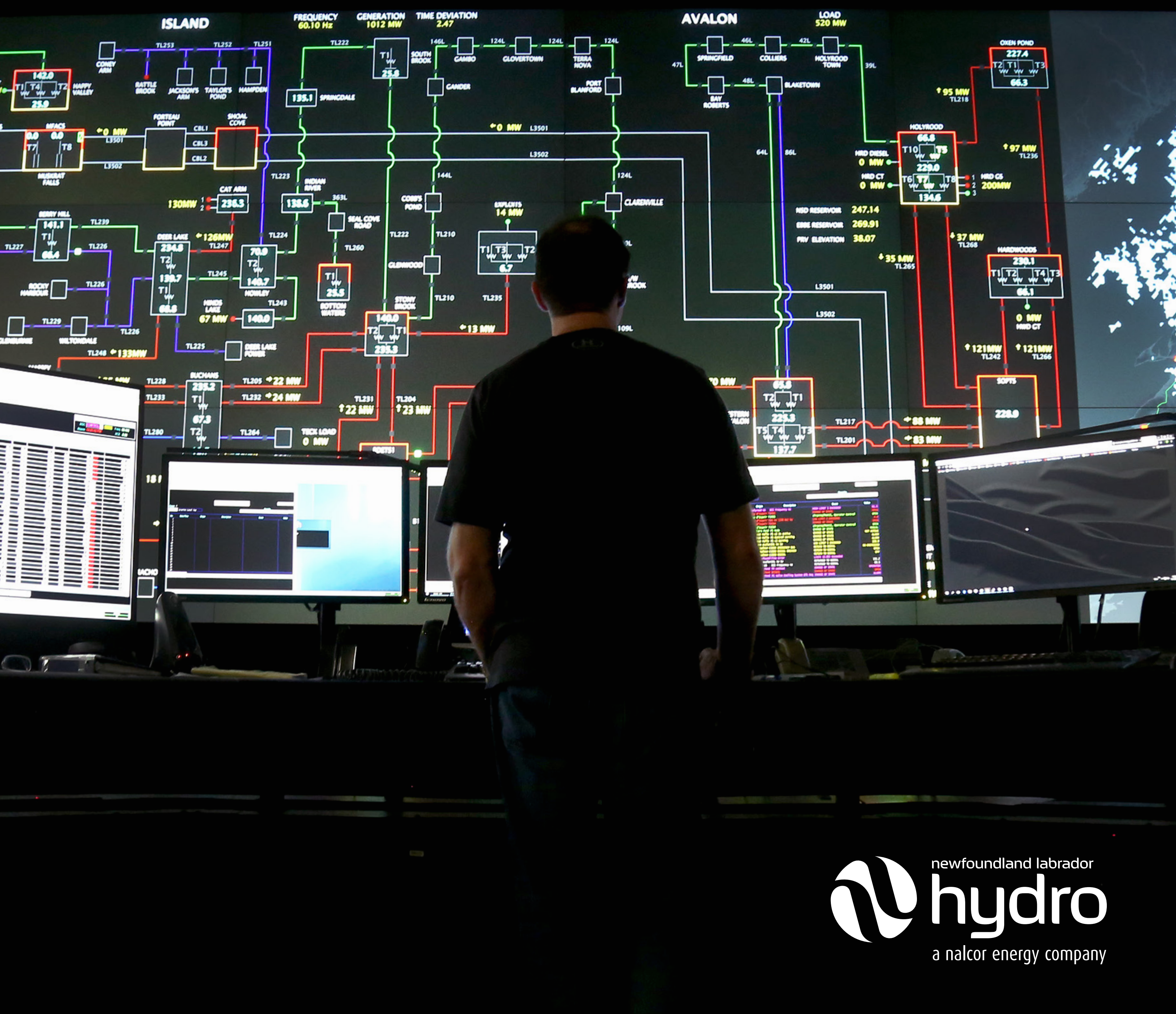
- Planning for Today, Tomorrow, and the Future – Summary Document
- Volume I: Study Methodology and Proposed Planning Criteria
- Volume II: Near-Term Reliability Report
- Volume III: Long-Term Resource Plan
- Abbreviations
- Definitions

Reliability and Resource Adequacy Study

November 16, 2018

newfoundland labrador hydro

PLANNING FOR TODAY, TOMORROW, AND THE FUTURE.



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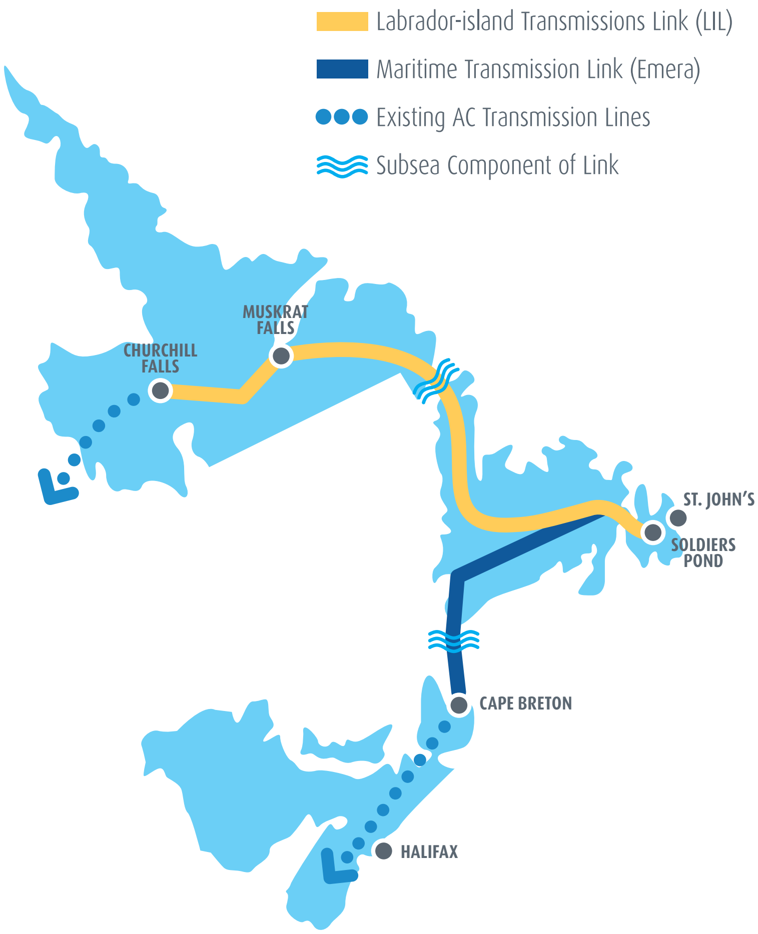
RELIABILITY AND RESOURCE PLANNING

Hydro's 2018 Reliability and Resource Adequacy Study addresses our long-term approach to providing continued least-cost, reliable service for our customers. To meet customer needs, we have completed a resource plan considering a range of possible scenarios over a ten-year planning horizon—covering the period from 2019 through 2028.

We have also shifted our thinking because of the connection to Labrador. Our planning going forward will be done on a provincial basis for the island and Labrador, together forming the Newfoundland and Labrador Interconnected System (NLIS). We're also adopting new planning criteria similar to that used by other utilities.

THE NEWFOUNDLAND AND LABRADOR INTERCONNECTED SYSTEM



With Hydro moving to planning on a provincial basis, we have made some key observations:

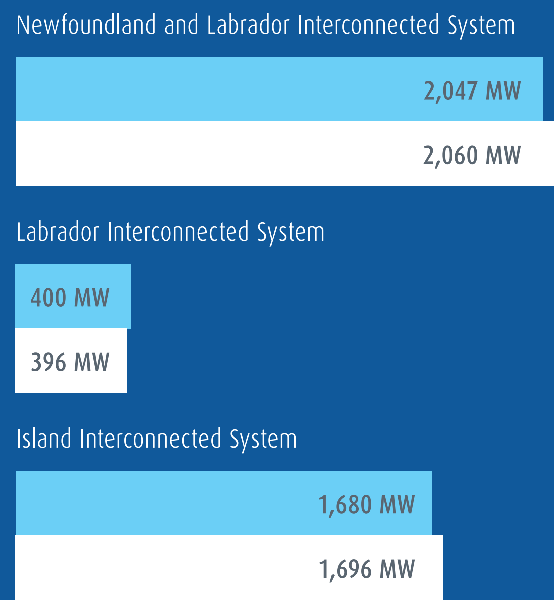
- Our expectations of customer electricity requirements, which form the base case, sees little change in customer needs over the next ten years.
- Changes in economic outlook can change customer's electricity requirements and expectations.
- Forecast customer electricity requirements are linked to the electricity rate after Muskrat Falls is in service.
- Any future changes will be reviewed in Hydro's annual update, providing time to ensure we're ready to meet emerging needs in a reasonable time frame.

BASE CASE

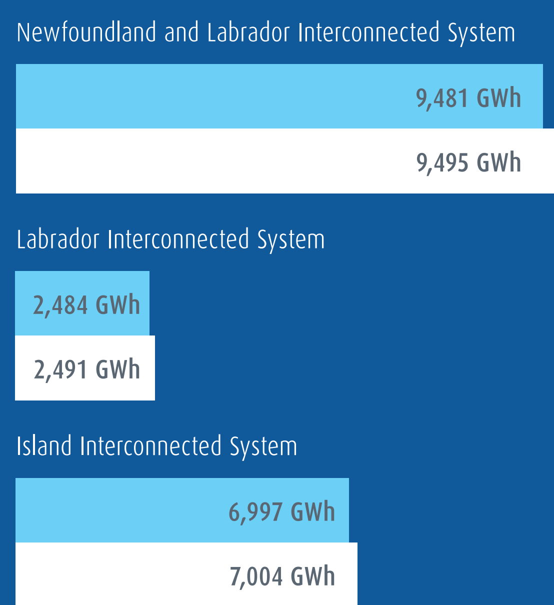
Expected case, determined by using the assumptions considered most likely to occur.

NEWFOUNDLAND AND LABRADOR INTERCONNECTED SYSTEM SNAPSHOT

CUSTOMER DEMAND REQUIREMENTS



CUSTOMER ENERGY REQUIREMENTS

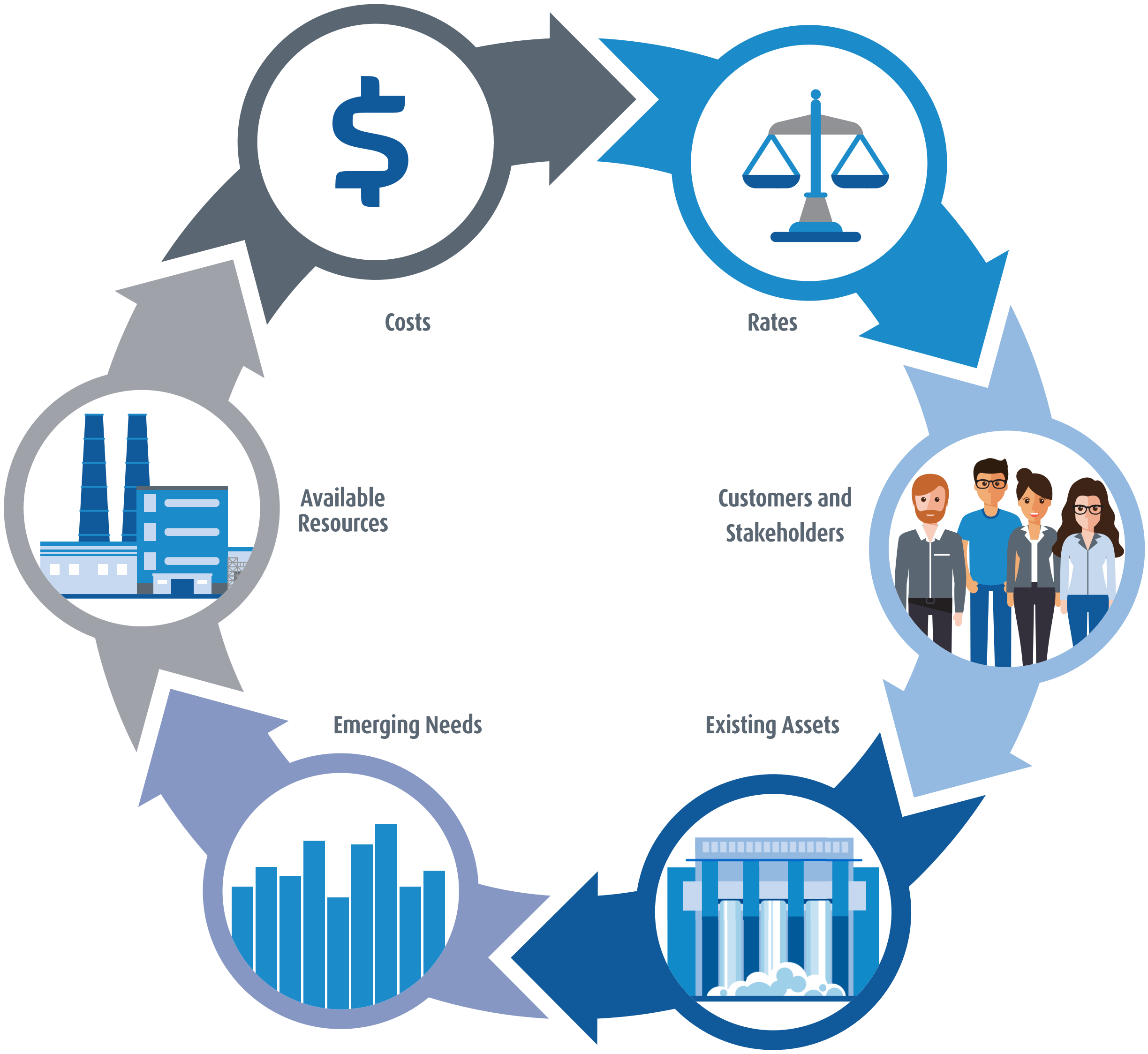


2018 2028

KEY OBSERVATION

The current base forecast sees little change in customer requirements over the next ten years.

THE RESOURCE PLANNING LIFECYCLE



KEY INPUTS	PLANNING HORIZON	RESOURCES EVALUATED
• Customer expectations • Provincial outlook • Asset in service and retirements	• Near term (1–5 years): Better risk informed recommendations and early identification of issues and trends • Long term (5+ years): Balances cost and reliability	• Diverse resource mix to meet changing system requirements • Available resource options
↓	↓	↓

RECOMMENDED RESOURCE PLAN

RESOURCE PLAN: A plan for incremental generation or supply resources that balances cost, reliability, and stakeholder expectations. Transmission requirements are evaluated separately.

HOW WERE OPTIONS CONSIDERED?

The resources considered were included in Hydro's planning tools, which are used to help determine the lowest-cost option that provides the necessary level of reliability.

The characteristics, location, and cost of each option are all examples of attributes that contribute to how well an option is suited to meet system needs.

WHAT RESOURCES WERE CONSIDERED AS PART OF THE ASSESSMENT?

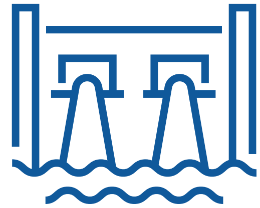
- **Alternatives:**
  - Wind
  - Solar
  - Batteries
  - Rate design (e.g. Time-of-Use Rates, Critical Peak Pricing)
  - Customer Demand Management (CDM)
  - Capacity assistance
  - Market purchases
- **Conventional generation:**
  - Hydro (building new generating plants or building additional generation at existing plants – e.g. another generator at Bay d'Espoir)
  - Gas turbines

MARKET PURCHASE

A purchase of capacity, energy, or reliability-related product from another jurisdiction.

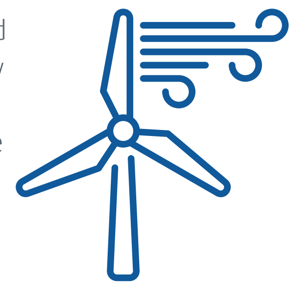
CURRENT RESOURCE MIX

HYDRO



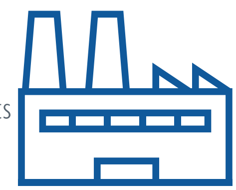
Clean, renewable, hydraulic generation is the backbone of our energy assets. Our hydraulic generating assets provide capacity and energy year-round to meet our customer's needs economically. In the current system, the Bay d'Espoir Hydroelectric Generating Station is the largest plant in the fleet, producing more than half of the Island's hydroelectric energy annually.

WIND



Since 2009, wind generation has provided energy for our customers. Hydro currently has agreements to purchase wind from two independent power producers on the Island System—one from a 27 MW wind farm in Fermeuse and the other from a 27 MW wind farm in St. Lawrence. These two wind farms provide about 2.5% of the total energy used on the Island annually.

THERMAL



The current interconnected system has three types of thermal generation: the Holyrood Thermal Generating Station; gas turbine plants at Hardwoods (near Paradise), Holyrood, Stephenville, and Happy Valley-Goose Bay; and diesel plants on the Avalon and Northern Peninsulas. The Holyrood Thermal Generating Station has been an important part of our electricity system for many years and will remain important to the electricity system until Muskrat Falls is successfully integrated into our provincial system. The Holyrood gas turbine will continue to provide capacity for years to come.

ENERGY EFFICIENCY AND CAPACITY ASSISTANCE

takeCHARGE is a joint initiative between Newfoundland and Labrador Hydro and Newfoundland Power that offers energy efficiency awareness and rebate programs. In 2017, the program achieved 34,434 MWh of energy savings.

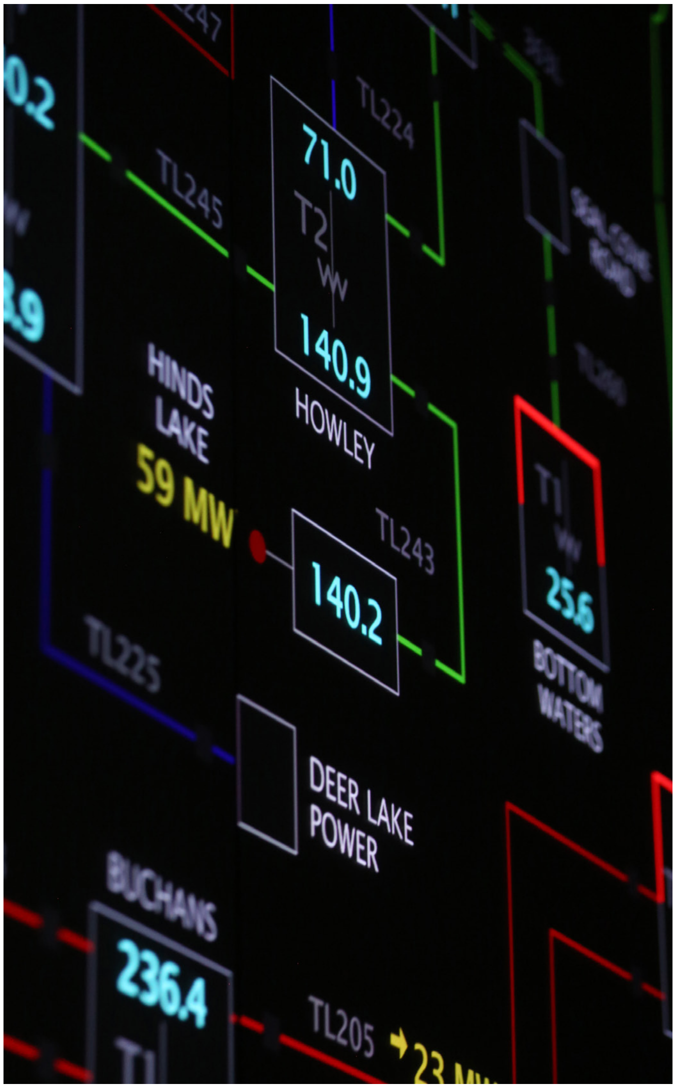
Hydro also has capacity assistance contracts with some of our large industrial customers. Industrial customers participating in these agreements reduce their consumption on a temporary basis, such as during times of high customer load or during multiple equipment outages, to make more electricity available for residential customers.

CHANGING SUPPLY MIX

The system is changing and will be more reliable than it is today. In the future, customers can help manage system demand by reducing consumption at times of high system load. Hydro is committed to working with customers and stakeholders to determine how programs like time-of-use rates can play a role in the future of our electricity system.

TIME-OF-USE RATES

Time-of-Use Rates offer prices that vary throughout the day based on customer load patterns, with the highest rates during peak hours and lowest rates during off-peak hours. This can enable customers to save money during hours when electricity is more expensive.



ISLAND INTERCONNECTED SYSTEM (IIS)

The IIS is the interconnected portion of the Island electrical system. It is characterized by large hydroelectric generation capability located off the Avalon Peninsula, and the bulk 230 kV transmission system extending from Stephenville in the west to St. John's in the east. In 2018, the IIS became interconnected to North America for the first time via the Labrador Island Link (LIL), which connects us to the Labrador Interconnected System (LIS), and the Maritime Link (ML), which connects us to Nova Scotia.

LABRADOR INTERCONNECTED SYSTEM (LIS)

The LIS is the interconnected portion of the Labrador electrical system. Central to the LIS is clean, renewable supply from Churchill Falls and transmission to the two major customer centres in Labrador East and Labrador West. The LIS is connected to the Island Interconnected System (IIS) via the Labrador Island Link (LIL). The LIS is also connected to the North American grid via the 735 kV AC transmission lines from Churchill Falls to Quebec.

MARITIME LINK (ML)

A 500 MW high voltage DC transmission line connecting Newfoundland and Nova Scotia.

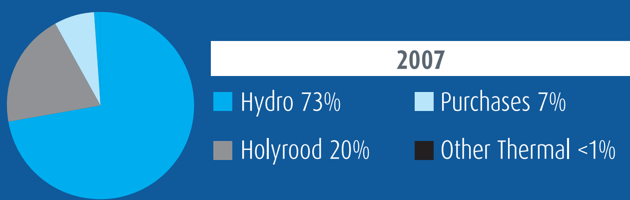
LABRADOR ISLAND LINK (LIL)

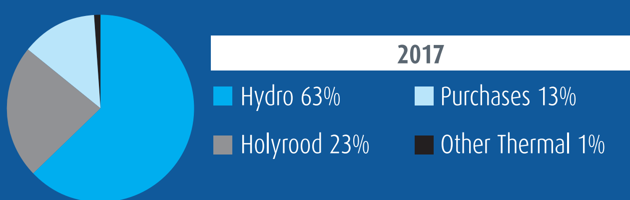
A 900 MW high voltage DC transmission line designed to deliver power from the Muskrat Falls Generating Station to Soldiers Pond Terminal Station on the Avalon Peninsula.

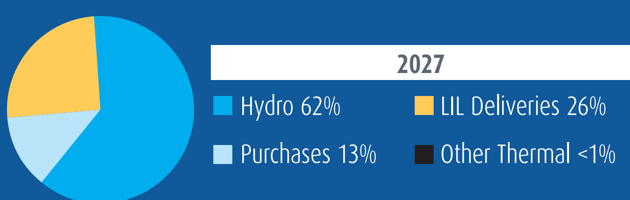
RESOURCE CONTRIBUTIONS*

CHANGING HOW WE MEET CUSTOMER ENERGY NEEDS ON THE ISLAND: PAST, PRESENT, AND FUTURE

Customers in Labrador will continue to be supplied with energy from Churchill Falls. By 2021, Hydro will meet 99% of all customer requirements with clean, renewable energy. The next few years will bring significant changes to how we supply our customers on the Island Interconnected System.







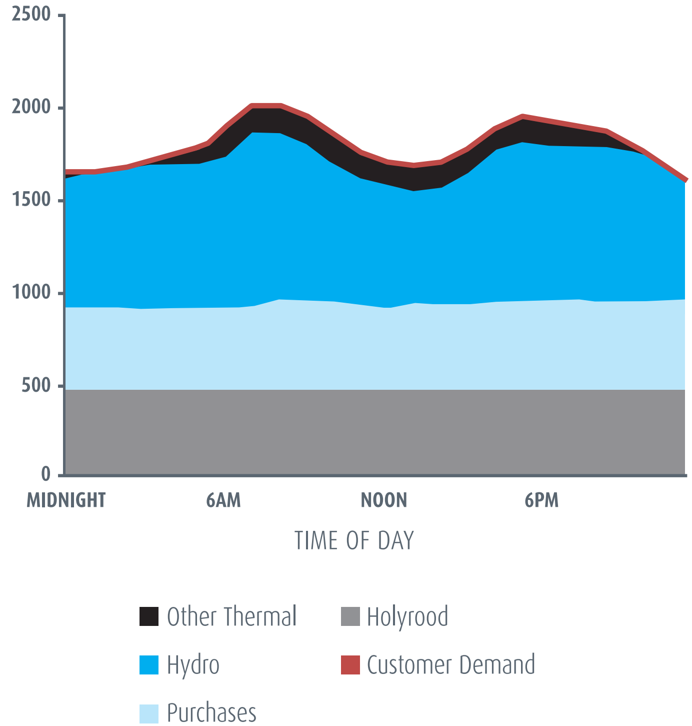
- On-island hydro, like Bay d'Espoir, will continue to play the same key role in the system supply mix, providing stable energy generation for years to come.
- Energy purchases have increased over the last number of years, primarily due to renewable purchases from wind and hydraulic energy from Exploits. This supply continues to play a key role in the future.
- Power delivered from Labrador will take the place of Holyrood, increasing the amount of clean, renewable generation to over 99% of total production.
- We are now able to import energy from other jurisdictions when it is economic to do so. While in the long-term the Maritime Link will be primarily used to export energy, in the short-term we can use lower cost purchases to reduce the amount of costly oil-fired generation produced at Holyrood.

Without Labrador

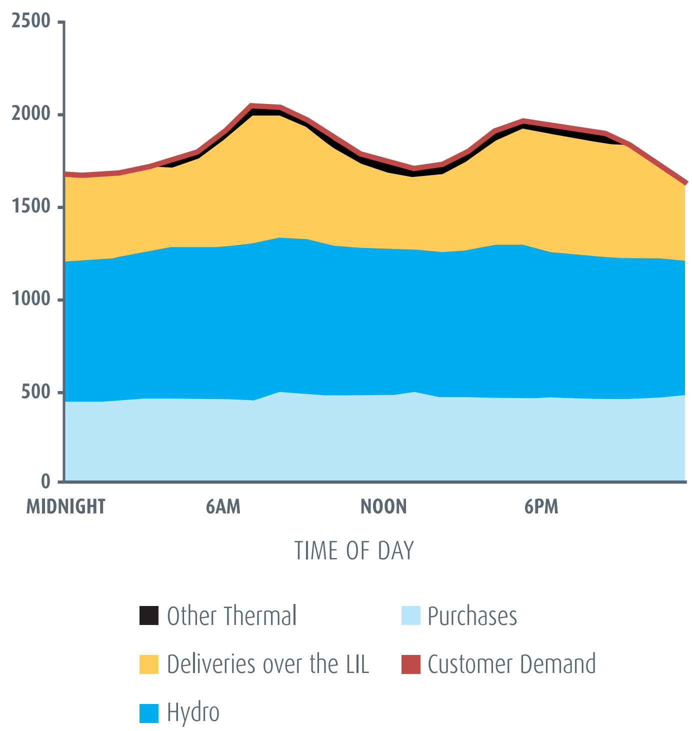
SNAPSHOT: HOW ASSETS WILL MEET CUSTOMER NEEDS ACROSS THE PROVINCE

These graphs give a snapshot of how we meet electricity needs across the province on our peak day. The change from our current system to after Muskrat Falls is in service shows the shift from thermal to include integration of the LIL.

CURRENT SYSTEM



AFTER MUSKRAT FALLS IN SERVICE



CUSTOMER & STAKEHOLDER ENGAGEMENT

METHODOLOGY & SCOPE

The intent of the engagement was to start a dialogue regarding electricity in the province with our customers and stakeholders—and the conversation is far from over. We used practices consistent with engagement activities used by other utilities across Canada.

Our approach used public engagement principles and an opt-in approach, allowing all residents in the province to join the conversation and, therefore, quotas for data collection were not put in place. However, it should be noted, the actual breakdown of respondents closely aligns with the true population distribution in the province.

A two-pronged approach for customer engagement was implemented—digital engagement with residential and small commercial customers along with one-on-one consultation with key stakeholders including: the Consumer Advocate, Industrial Customers, and Newfoundland Power.

CUSTOMER ENGAGEMENT

Our customer engagement offered two participation opportunities—a digital engagement along with an option to join a longer-term customer panel. Input was gathered from 2,070 provincial electricity customers in August and September of 2018.

Through our customer engagement initiative, expectations for reliability, cost, customer options, and rate design were gathered and will be used to inform our recommendations.

We value the importance of seeking customer input for consideration and decision making purposes. Customer input, along with analysis and evidence, help us make informed decisions about the future of electricity in our province.

ENGAGEMENT TYPE	ONLINE
DATES	AUG 28 – SEPT 20, 2018
NUMBER OF COMPLETES	2,070
AVERAGE ENGAGEMENT LENGTH	16 MINUTES

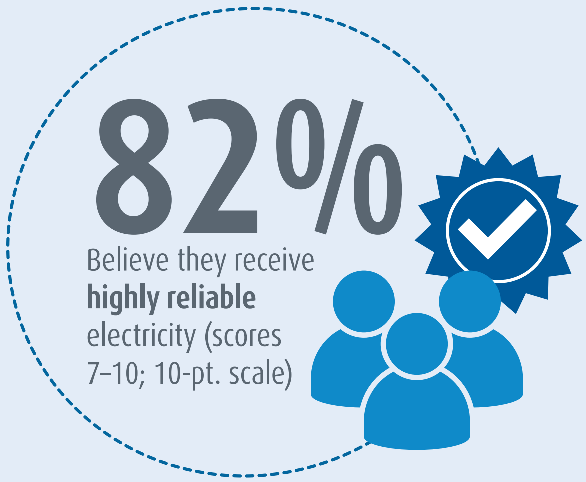
WHAT WE HEARD

Reliability:

We asked customers how they feel about the current reliability of their power supply as analysis is happening now to determine the amount and type of investments we make for the future of energy in our province.

While the engagement results showed differences among regions and customer type, overall respondents indicated they believe NL's power system to be reliable. However, they do not want an increased frequency of outages.

Any proposed plan for future investment will meet reliability standards, good utility practice, and Hydro's commitment to continue to meet customer's expectations.



Balance between reliability and cost:

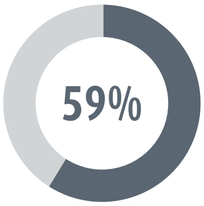
Electricity rates are a concern for Newfoundlanders and Labradorians, which is why we asked for input to determine the right balance between reliability and the cost of those investments for customers.

Customers demonstrated they are cost-sensitive and would prefer investments in the system be made cautiously. Overall, most respondents favour an approach that involves good reliability with a lower impact on cost.

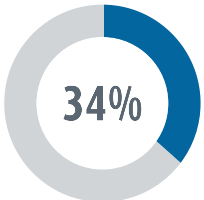
Very few respondents were in favour of an investment strategy that, while offering the best reliability, would mean a higher impact on electricity costs.

With the majority of customers noting a preference for cautious investment, it's our responsibility to ensure that any recommended resource plan ultimately balances cost with reliability.

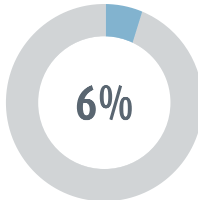
PREFERRED BALANCE: RELIABLITY VS. IMPACT ON COST



Good reliability– **Lower** impact on cost



Better reliability– **Moderate** impact on cost



Best reliability– **Higher** impact on cost

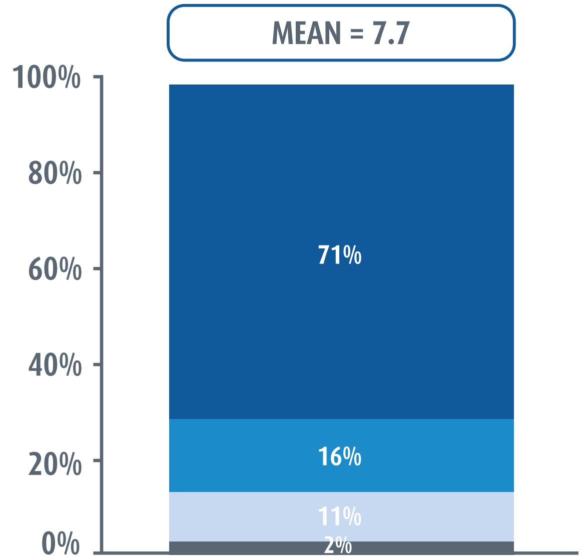
OPINIONS REGARDING CURRENT SYSTEM AND FUTURE INVESTMENT

(% offering high levels of agreement: scores 7–10; 10-pt. scale)

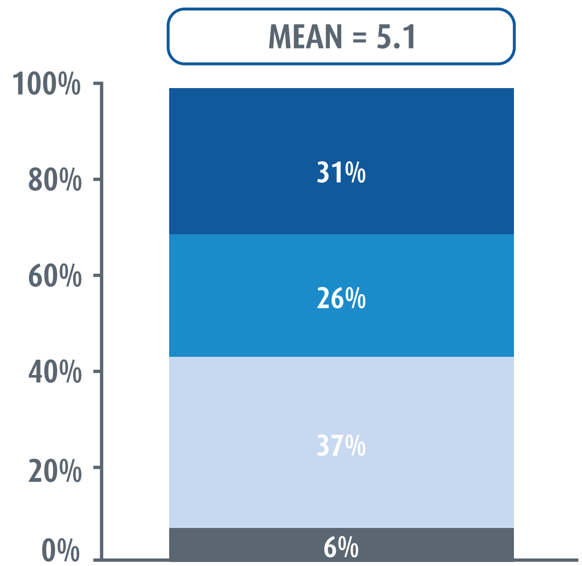
My power reliability has improved since DarkNL.	**57%**
NL needs a more reliable system than it has right now.	**47%**
I am comfortable with our power system's current level of reliability and prefer additional investment be made cautiously.	**71%**
Hydro should invest in more generation to further reduce the impact of power supply interruptions during extreme events.	**31%**

OPINION OF STATEMENTS ABOUT INVESTMENT

Rating on 10-pt Scale: 1=Completely Disagree, 10=Completely Agree



I am comfortable with our power system's current level of reliability, so I would prefer that additional investments be made cautiously.



Hydro should invest in more generation to further reduce the impact of power supply interruptions during extreme events.

Top 4 (7–10)
Middle 2 (5–6)
Bottom (1–4)
Don't know/Not sure

Q. 8a-b: Please indicate to what extent you agree or disagree with each other of the following statements. (n=2070)

Responses of 'Don't know/Not sure' have been excluded from the calculation of the mean.

CUSTOMER OPTIONS

Respondents readily acknowledge that customers have a role to play in actively managing electricity consumption and are keenly interested in learning more about their own electricity usage.

Moreover, the vast majority of respondents would like Hydro to explore more customer rate options and demonstrate a high level of interest in Time-of-Use Rates.

63%

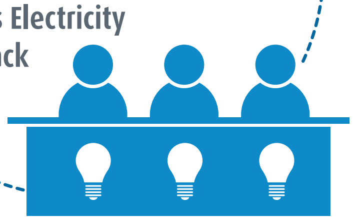
of respondents are highly interested in **Time-of-Use Rates.** (scores 7–10; 10-pt scale)

CONTINUED ENGAGEMENT

There is clear interest in continued engagement with Hydro. Although many respondents were unsure of how Hydro could do a better job of this, the majority of respondents did express interest in joining Hydro's Electricity Feedback Panel. To date, we have approximately 630 electricity customers registered to the panel.

57%

are interested in joining **Hydro's Electricity Feedback Panel.**



NEWFOUNDLAND POWER

Hydro met with Newfoundland Power executive and engaged staff throughout the course of its study to provide opportunities for input and questions. Various departments also provided assistance in the development of modelling assumptions and study components.

INDUSTRIAL CUSTOMERS

Hydro met with each of its industrial customers to give an overview of the study and provide an opportunity for input, questions, and feedback. Overall, industrial customers generally agreed with the proposed approach for study execution, with many commenting on the comprehensiveness of the presented project scope.

CONSUMER ADVOCATE

The Consumer Advocate remarked on the inclusion of Customer Demand Management as a resource option as a positive step forward, noting that customers continue to be concerned about future electricity costs and would likely benefit from additional flexibility and options.

NEAR-TERM RESOURCE ADEQUACY

We are focused on our ability to meet our customers' requirements in the near-term (the next one to five years). This assessment takes an in-depth view of system risks and mitigating measures to ensure we can reliably meet the needs of our customers through the full system transition to Muskrat Falls in-service and the Holyrood plant retirement.

There are three key focus areas when discussing near-term resource adequacy:

1. **AVAILABILITY OF THE TRANSMISSION LINE FROM MUSKRAT FALLS**
   The availability of the Labrador Island Link (LIL) contributes to our ability to reliably supply customers before power is available from the Muskrat Falls Generating Station. The line is currently in testing and is expected to be able to provide power for Island customers beginning in early 2019. Hydro is working closely with the project owner and partner, Nalcor Energy, to understand any risks around the availability of the line and its ability to deliver power to the Island. To keep the lines of communication open, we provide bi-weekly reports to our stakeholders on our progress.

2. **HOLYROOD THERMAL GENERATING STATION**
   Holyrood has played an important role in the Island electrical system for almost 50 years. While the plant is now approaching end of life, it will continue to be critical to system reliability until generation is available at Muskrat Falls. Hydro continues to invest prudently in Holyrood to make sure that the plant remains reliable until its retirement in 2021. For example, in 2018 Hydro completed a project to restore the full capability of the generating units at Holyrood, which had seen a reduction in capability over the previous winter.

3. **AVAILABILITY OF GENERATION AT MUSKRAT FALLS GENERATING STATION**
   Commissioning activities at Muskrat Falls are expected to begin on the first of the four generating units in 2019, with the full plant expected to be operational in 2020. Similar to the LIL, Hydro will be working closely with the Nalcor Energy team through this process to ensure system readiness.

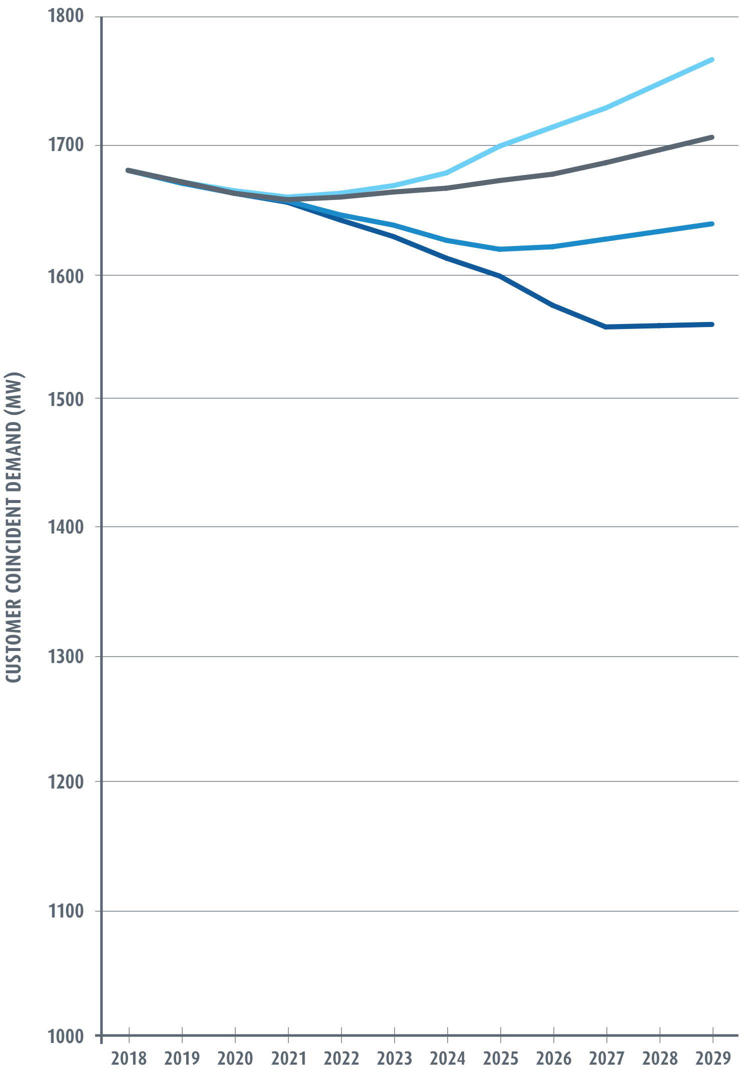
Hydro is focused on mitigating risks that could impact our ability to supply customers while carefully managing costs. For example, Hydro has executed a contingency plan for the unlikely event that the line from Muskrat Falls is not available in the coming winter. Hydro has also contracted Capacity Assistance from its Industrial Customers through 2022, to provide additional flexibility as the Muskrat Falls assets become operational.

FACTORS IMPACTING PROVINCIAL ELECTRICITY SUPPLY

UNCERTAINTY AND ELECTRICITY RATES

Preparing for future electrical system growth is a complex process. On the one hand, being over-prepared can mean unnecessary investment, further increasing the cost of electricity. However, being under-prepared could mean a delay in our ability to meet growing customer requirements and support the economy. To build a preliminary understanding of how customer requirements may vary over the next 10 years, the resource adequacy analysis considered a range of electricity rates for Island customers.

Island Interconnected System Forecast Annual Peak Demand Analysis



Retail rates alone could mean a difference of 200 MW in forecast peak demands between the cases considered.

- Case I: Low Retail Rate
- Case II: Mid Retail Rate
- Case III: High Retail Rate
- Case IV: High Load Growth

CONSIDERED SCENARIOS

Hydro examined 24 different cases as part of the reliability and resource adequacy analysis. Hydro had to analyze what additional resources would be required into the future for each of the various cases.

FOUR POTENTIAL ISLAND LOAD SCENARIOS

P50 VS P90 PLANNING CRITERA

THREE POTENTIAL LABRADOR LOAD SCENARIOS

24 DISCRETE SCENARIOS

P50 FORCAST

In a P50 forecast, the actual peak demand is expected to be below the forecast number 50% of the time and above 50% of the time (i.e. the average forecast).

P90 FORCAST

In a P90 forecast, the actual peak demand is expected to be below the forecast number 90% of the time and above the forecast 10% of the time. While in this case there is a smaller chance of the actual peak demand exceeding the forecast peak demand, it requires planning to have more generation available, which increases costs.

Remoteness of Supply

Muskrat Falls is further from the majority of customers (Avalon Peninsula) than any current or pre-existing generation assets. However, the line from Muskrat Falls has been designed for the rough, rugged terrain and geographic challenges posed by the most remote places in our province.

While infrequent outages may occur, emergency restoration plans are in place to restore power to our customers in a safe and expedient manner.

Aging Infrastructure

The majority of the existing electricity system assets have been in service since the 1960s. These assets require the right capital investment and proactive maintenance to ensure they continue to provide stable, reliable electricity for our customers. The cost of this maintenance and investment is balanced to deliver the reliability our customers expect.

LOAD GROWTH IN LABRADOR

Potential Industrial Development

Hydro works with new and existing customers to understand any changes in their electricity needs. Over the past few months there have been several positive announcements around the potential for industrial development in Labrador. These potential developments could mean increased electricity requirements in the province. Growing requirements in Labrador and the impact on the transmission system were the subject of another study by Hydro that has recently been submitted to the Public Utilities Board.

As the timing and certainty of electricity requirements for those developments becomes clearer, Hydro will update this resource study. Should the results change, Hydro will inform stakeholders.

Data Centre Interest

As reliance on technology grows, so does the infrastructure required to support digital development. In recent years, the electricity industry has seen a significant increase in service requests from data centres. Data centres are particularly attracted to locations with low rates, given their relatively high electricity consumption. Based on the current rates in Labrador, there has been significant interest from data centre facilities to establish operations in the area.

Factors Impacting on Provincial Electricity Supply

As Labrador is currently supplied by energy from Churchill Falls, contractually, there is currently a finite amount of energy available for consumption in the region. This means that any identified requirements over and above what those sources can supply would require additional supply. Should the need arise, considering the best option on a provincial basis is in customers' best interest. This could result in a market purchase of capacity delivered to Labrador, or the construction of additional generating sources. The addition of more electricity for any system would require electricity rates to be updated to reflect those costs.

DATA CENTRE

A network of computer servers typically used for processing large amounts of information.

FOCUS ON INTEGRATION

Interconnection with the North American grid and the move away from reliance on Holyrood is the biggest change to our system since initial electrification in the 1960s. We know this is a big change and are taking appropriate measures to ensure we're prepared to provide the support necessary to make the transition and also take advantage of the new opportunities it will present.

COMMISSIONING ACTIVITIES

Both the Muskrat Falls Generating Station and the Labrador Island Link are new assets that will contribute to the provincial electricity system for many years. As with any newly built asset, there are a series of steps that must be taken and testing that must occur to ensure everything is working as it should before the assets can be transitioned into operations. Hydro is actively monitoring these activities and working closely with the project teams at Nalcor Energy, ensuring that the Public Utilities Board and stakeholders are aware of ongoing activities and that these activities are being undertaken with minimal risk to system operation.

COMMISSIONING
Transitioning newly built assets into working, operational plants.

CREATION OF THE NEWFOUNDLAND AND LABRADOR SYSTEM OPERATOR (NLSO)

The creation of the Newfoundland and Labrador System Operator (NLSO) is an important step in the integration of the Muskrat Falls assets into the provincial electrical system and the Island's interconnection with the North American electricity grid. The NLSO will operate the facilities owned by Hydro and Nalcor along with interconnections to Emera's Maritime Link assets on the Island. They are responsible for ensuring the reliable and safe operation of the province's electrical system.

ACTIVITIES IN ENERGY MARKETS

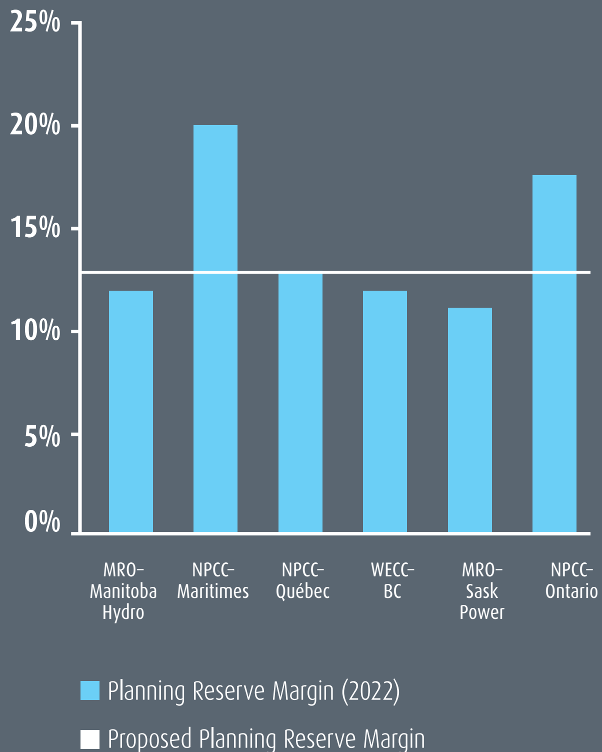
For the first time, the Island is interconnected to the North American grid. This means increased operational flexibility and the ability to partner with neighboring regions both on a planned basis, for example selling energy when we have excess, and an unplanned basis, for example importing energy when a unit trips. As we advance in our market activities, we will optimize our participation to maximize the value of our assets and ultimately lower operating costs.

COST OF NEW RESOURCES

Electricity is made up of two components: capacity, which is the demand for energy at any given time measured in megawatts (MW); and energy, which is the amount of electricity used over a period of time measured in gigawatt-hours (GWh). When considering whether or not additional resources are required, we take both energy and capacity into consideration.

PEAK DEMAND
The highest amount of electricity consumed in an hour occurring within a year.

Now that we're interconnected to the North American grid, Hydro is moving to adopt planning criteria similar to that used by other utilities. This criteria will be used to determine when additional resources are needed to supply our customers.



Utilities with a predominantly hydraulic asset base typically have lower reserve margins than those with thermal or variable generation, as hydraulic assets are generally more reliable.

Across the 24 scenarios considered, we are not forecasting an energy shortfall. However, capacity shortfalls are forecasted to occur in 7 of the 24 scenarios considered.

The majority of the capacity shortfalls are projected to begin in the late 2020s. The most prudent approach is to continue to monitor and make a full decision when there is more certainty, as variations in assumptions can shift the timing for required additional investment. We need to better understand the operation of the future system before making a final decision on investment. During this time, Hydro's role is to continue to review available options on an annual basis, to ensure whatever we are recommending is the best solution for our customers.

In two of the considered cases, resources are required in the early 2020s. These cases are outside what utilities typically plan for. We are committed to working with stakeholders and the Public Utilities Board to continue to determine how these scenarios fit in the balance of cost and reliability. The table below provides a summary of our analysis.

Island Load Case	P50 vs P90	Labrador Load Case	Year of resource requirements
Case I: Low-Rate	P90	High Industrial Growth	2028
		Recapture Fully Consumed in Labrador	2023
Case IV: High Load Growth	P50	High Industrial Growth	2028
		Recapture Fully Consumed in Labrador	2026
	P90	Base Labrador Load	2027
		High Industrial Growth	2025
		Recapture Fully Consumed in Labrador	2022, 2028

ACTION PLAN

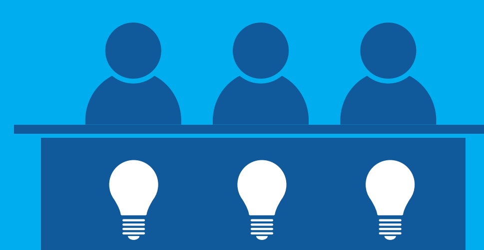
Hydro looks forward to participating in the regulatory process to examine the results of this study. We expect this process to commence following the submission of this report and we will continue to work with stakeholders and the Board to determine which scenarios should drive capital investment.

We will carefully monitor potential for electricity rate design and load growth. We will also continue to study the role alternative technologies, such as battery storage technology, could play in the future. We will work to understand the risks that exist in our system, and where possible and practical, implement solutions to increase reliability for customers.

Long-term planning takes a conservative approach and, therefore, we will not make significant investments in the system until the need is well understood and all options have been carefully considered.

HAVE FEEDBACK?

Join Hydro's Electricity Feedback Panel: electricityfeedbacknl.com



Reliability and Resource Adequacy Study

Volume I: Study Methodology and Proposed Planning Criteria

November 16, 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Executive Summary

Newfoundland and Labrador Hydro's ("Hydro") Reliability and Resource Adequacy Study ("Study") addresses the company's long-term approach to providing continued least-cost, reliable service for its customers by establishing an action plan to meet customer demand and energy requirements in consideration of a range of scenarios. In this analysis, Hydro has analyzed its ability to meet customer and system requirements reliably over a ten-year planning horizon; covering the period from 2019 through 2028 ("Study Period").[1] Hydro is proposing to file an annual assessment of resource adequacy.

This Study is presented as three volumes. Volume I outlines Hydro's Study Methodology and Proposed Planning Criteria. Volume II provides an in-depth view of near-term resource adequacy. Volume III provides the long-term resource planning considerations, resource options available to meet the criteria proposed in Volume I, and Hydro's proposed action plan. Additionally, a Summary Document is included to highlight, in brief, the key considerations of the Study.

As part of this process, resource plans have been developed to help guide decision making around reliability requirements and the associated investment in resources in consideration of severe weather and low probability, high-impact loss of supply. The current resource plans were developed by evaluating a number of resource options using Hydro's detailed modelling tool, PLEXOS®.[2]

Since the last assessment of long-term resource adequacy in 2012, significant system changes have occurred which required adaptation of planning tools and processes. One noteworthy change is the planning of the system on a provincial basis (as opposed to separate Island and

[1] Reporting on a ten-year planning horizon is observed in the "2017 Long-Term Reliability Assessment," North American Electric Reliability Corporation ("NERC"). <https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf>

[2] PLEXOS® is a power system simulation tool, developed by Energy Exemplar.

Labrador planning areas), including the addition of interconnection to the North American grid. In consideration of interconnection to the North American grid, Hydro undertook a full review of its planning criteria. This review considered Hydro's past practices, a review of other utility practices, and the intention to voluntarily comply with North American Electric Reliability Corporation ("NERC") reliability standards. To ensure appropriate treatment and modelling of new system components and capabilities, external consultants were engaged to review both the practices and the implementation of these practices in PLEXOS®. Independent reports have been provided by each consultant and are included in this Study.[3]

Based on the work conducted, Hydro recommends modifications to both the probabilistic and deterministic capacity planning criteria. The system energy planning criteria is proposed to be extended to the entire Newfoundland and Labrador Interconnected System ("NLIS").

Development of the resource plans considered a number of core assumptions including base and sensitivity load forecasts, asset retirement dates, in-service dates for the Lower Churchill Project assets, asset capacity and energy capabilities, asset reliability, and bulk transmission system representation.

The requirement for incremental supply is primarily driven by resource retirements, changes in system requirements,[4] and changes in customer requirements. While the retirement of existing assets, in-service dates of new assets and changes in system requirements are currently well known, uncertainty remains about potential changes in customer requirements. Since rates are a key driver of customer usage, a range of retail rates were considered to determine the sensitivity of the proposed resource plans to customer costs.

[3] Refer to Volume 1, Attachment 1 for external review and validation reports.
[4] Hydro is addressing compliance requirements in this analysis as established by both NERC and the Northeast Power Coordinating Council ("NPCC").

To complement the technical efforts which form the foundation of this analysis, this report includes Hydro's findings from stakeholder consultations undertaken to inform the resource planning process. This involved consultation focused on reliability and resource planning with Newfoundland Power, Hydro's Industrial Customers, the Consumer Advocate, and provincial electricity customers. Hydro met with the Newfoundland Power Executive and engaged various staff members throughout the course of its study.[5] Through discussion, the Industrial Customers generally expressed that the methodology presented was comprehensive. The Consumer Advocate remarked on the inclusion of Customer Demand Management as a Resource Option as a positive step forward, noting that customers continue to be concerned about future electricity costs and would likely benefit from additional flexibility and options. Customers were cost-sensitive when presented with information on future investment and showed a preference for cautious incremental investment. A majority of respondents expressed interest in continued dialogue with Hydro by expressing interest in joining Hydro's Electricity Feedback Panel.[6] The consultation process with customers was valuable and similar consultations will be included in future system planning processes.

The following key conclusions were drawn from the Study analysis:

- In accordance with good utility practice, Hydro recommends the adoption of the following resource adequacy criteria post-interconnection:[7,8]
    - Compliance with planning criteria be tested probabilistically to ensure that the loss of load expectation ("LOLE"), which represents the likelihood of disconnecting firm load due to resource deficiencies, shall be no more than one day in ten years (0.1 day per year). The 0.1 criterion will drive the required level of reserve margin.

[5] Newfoundland Power staff was engaged on matters including the modelling of Newfoundland Power assets in Hydro's models, Customer Demand Management, and the Customer Engagement strategy.
[6] Hydro intends to create an Electricity Feedback Panel to better engage customers in key decision-making.
[7] Post-interconnection refers to the period after full integration of all Lower Churchill Project assets, planned for Q3 2020.
[8] Existing criteria will continue to apply in advance of the full in-service of the MFGS.

- Compliance with planning criteria be tested deterministically to ensure that the reserve margin is adequate to meet Northeast Power Coordinating Council's ("NPCC") operational requirement for ten and thirty-minute reserves.[9]
- The higher reserve or more conservative requirement of either the probabilistic or deterministic required reserves will influence the planning process.
- Existing energy criteria will be extended to cover the entire NLIS so that sufficient resource capability will be available to supply firm energy requirements with firm system capability[10] throughout the study period.

- Resource adequacy will continue to be assessed on the basis of both probabilistic and deterministic criteria.
- The system will be planned on a provincial basis, with specific capacity requirements identified for the Island Interconnected System.
- If significant load growth in Labrador materializes, incremental provincial supply could be required as early as 2022.
- Impacts of investment and costs on retail rates and customer reaction to those impacts remains the most significant contributor to uncertainty in this process.
- Use of the P90 peak demand forecast as the base forecast for supply planning increases the required capacity to meet the base system peak demand forecast by more than 60 MW and advances resource requirements.

While an action plan is proposed, continued consultation and discussion with the Newfoundland and Labrador Board of Commissioners of Public Utilities ("Board") and other stakeholders will result in the most appropriate investment for customers.

Hydro recognizes that supply adequacy in advance of the availability of full production from the Lower Churchill Project assets is important for its stakeholders. The enclosed assessment of

[9] NPCC is a regional entity division which operates under a delegation agreement with NERC.
[10] Firm system capability refers to energy guaranteed to be available

near-term adequacy takes an in-depth view of system risks and mitigating options to ensure Hydro can reliably meet the needs of its customers through to full in service of the Lower Churchill Project Assets.

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1 Introduction

1.1 Newfoundland and Labrador Interconnected System Overview

There are two primary areas or zones of electrical infrastructure in the NLIS; the Island Interconnected System ("IIS") and the Labrador Interconnected System ("LIS"). A system map is presented in Figure 1.

> **The Newfoundland and Labrador Interconnected System includes:**
> - **Island Interconnected System**
> - **Labrador Interconnected System**

The IIS is primarily characterized by large hydroelectric generation capability located off the Avalon Peninsula, and the 230 kV bulk transmission system extending from Stephenville in the west to St. John's in the east. Currently, the two largest sources of generation on the island are the Bay d'Espoir plant[11] and the Holyrood Thermal Generating Station ("Holyrood").[12] The IIS is interconnected to the LIS via the Labrador-Island Link ("LIL"), a 900 MW high voltage dc transmission line designed to deliver power from the Muskrat Falls Generating Station ("MFGS") to Soldiers Pond Terminal Station on the Avalon Peninsula. The IIS is also connected to the North American grid via the Maritime Link ("ML"), a high voltage dc transmission line connecting Newfoundland and Nova Scotia.

The LIS is primarily characterized by supply at Churchill Falls, and transmission to the two major load centres in Labrador East and Labrador West. The supply at Churchill Falls is provided by

[11] A 613 MW hydraulic plant on the south coast of the island.
[12] A 490 MW large oil-fired thermal generating plant located on the Avalon Peninsula.

two sources; the TwinCo[13] Block and Recapture Energy. [14,15] The LIS is connected to the IIS via the LIL. The LIS is also connected to the North American grid via the 735 kV ac transmission lines from Churchill Falls to Québec.

Work is currently underway on the construction and integration of the Lower Churchill Project Assets, which consists of the Labrador Transmission Assets ("LTA"), the ML,[16] the LIL, and the MFGS. Both the LTA and the ML were placed in service in 2018. It is anticipated that the LIL will deliver electricity to the IIS in 2019.[17] The final aspect of the project, the MFGS (an 824 MW plant, four 206 MW units), is anticipated to produce first power in 2019, with full in service in Q3 of 2020.

Figure 1 presents an overview of the Lower Churchill Project Assets, which will interconnect to form part of the NLIS.

[13] Twin Falls Power Corporation Limited ("TwinCo").

[14] The TwinCo block of power is a firm 225 MW block of power and energy, capable of supplying 1,971 GWh per year for use in Labrador West.

[15] The Recapture Energy is a source of 300 MW of capacity at a 90 percent monthly load factor available at Point A. The amount of Recapture Energy available at the Churchill Falls bus is different from the 300 MW stated at the border due to the difference in location. The original Hydro Québec 1969 Power Contract has the delivery point for the 300 MW as *"the point in Labrador on the transmission lines from the CF(L)Co Plant towards the Province of Québec which is at the height of land, about opposite present Mile 148.8 on the Québec North Shore and Labrador Railway, which is the presumed watershed between the St. Lawrence River and the Churchill River."*

[16] The Maritime Link is a 500 megawatt (+/- 200 kV) High Voltage direct current ("HVdc") transmission line, as well as a 230 kV High Voltage alternating current ("HVac") transmission line and associated infrastructure, connecting Newfoundland and Labrador to Nova Scotia.

[17] The LIL remains in commissioning and is anticipated to be available for Hydro's use in winter 2018-2019 on an interim basis until full commissioning is completed following the availability of sufficient generation at the MFGS.

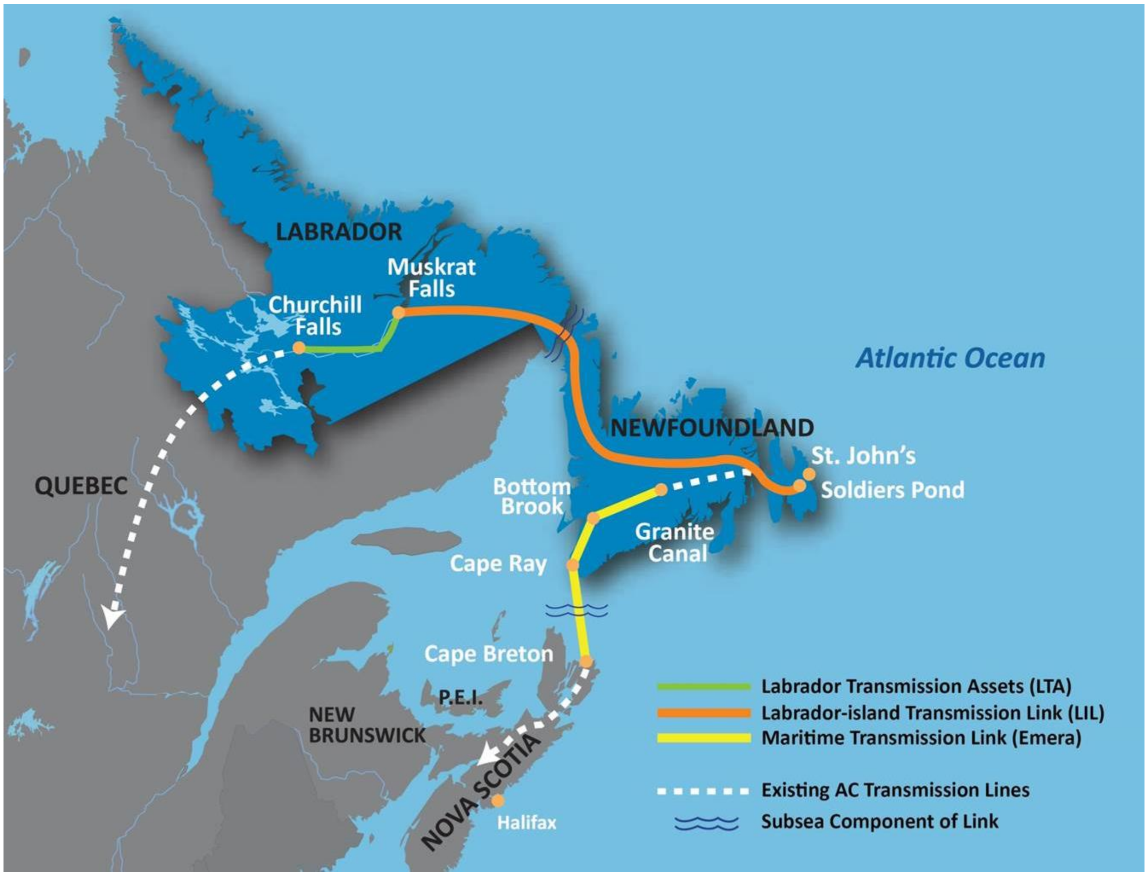

Figure 1: Lower Churchill Project Assets

1.2 Hydro's Mandate and Resource Planning

Hydro is the primary generator of electricity in Newfoundland and Labrador. Hydro's statutory mandate is provided in subsection 5(1) of the *Hydro Corporation Act, 2007* as follows:

> ***"The objects of the corporation are to develop and purchase power on an economic and efficient basis … and to supply power, at rates consistent with sound financial administration, for domestic, commercial, industrial or other uses in the province…"***

A comprehensive set of results from Hydro's resource planning exercises was last filed with the Board in 2012. That report, "Generation Planning Issues Report 2012," was primarily focused on ensuring reliable, least-cost supply for the IIS.

Hydro is now interconnected to the North American grid via the ML and the LIL. This report proposes changes to resource planning criteria stemming from the system changes as a result of interconnection. This Study details:

- The migration to planning on a regional and sub-regional basis;[18]
- The development of the proposed planning criteria;
- The proposed planning criteria;
- External validation of the Study approach and results;
- A description of resources available to meet customer and system requirements; and
- The identification of timing by which incremental resources are likely to be required.

The *Electrical Power Control Act* states: [19]

> ***6. (1) The public utilities board has the authority and the responsibility to ensure that adequate planning occurs for the future production, transmission and distribution of power in the province.***
>
> ***(2) The public utilities board may direct a producer or retailer to perform such activities and provide such information as it considers necessary for such planning to the public utilities board or to any other producer or retailer on such terms and conditions as it may prescribe.***
>
> ***(3) For the purpose of this section, the public utilities board may adopt those rules and procedures that it considers necessary or advisable to give effect to the subsection.***

The future reliability of the IIS also formed part of Order No. P.U. 3(2014), Schedule "A", which ordered an evaluation of the IIS adequacy and reliability up to and after the interconnection with the MFGS.

[18] From a capacity planning perspective, the IIS and the LIS form a planning region called the NLIS, and IIS forms a sub-region. For additional detail, please refer to Section 3.3.1.
[19] *Electrical Power Control Act, 1994,* "An Act to Regulate the Electrical Power Resources of Newfoundland and Labrador," Chapter E-5.1 <https://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm>

The Order referred specifically to evaluation of the requirement for:

- ***"Back-up generation and/or alternative supply requirements after interconnection***
- ***Other system planning, capital and operational issues which may impact adequacy and reliability before and after interconnection."***

This report is filed to assist the Board in ensuring adequate system planning occurs. System planning entails the development and assessment of supply adequacy under various potential future realities. This ensures that both sufficient capacity and energy are available to meet customer and system requirements and determines appropriate timing of requirements for additional supply. This analysis focused on the ability to reliably meet customer and system requirements over a ten-year planning horizon, covering the period from 2019 through 2028.[20] Operational requirements, such as spinning reserve, have also been evaluated as part of the Study; refer to Section 3.3.1 and Volume III for more detailed discussion. Hydro intends to update and file its assessment of resource adequacy annually. Hydro is proposing to the Board that the Near-Term Generation Adequacy report, currently required to be filed semi-annually, be included with this assessment and filed annually.

Resource Planning

- **Capacity Perspective: Probabilistic and deterministic assessment of supply adequacy**
- **Energy Perspective: Assessment of ability to meet firm requirements with firm energy**

From a capacity perspective, in accordance with industry practice, both probabilistic and deterministic assessments of adequacy were completed. Probabilistic assessments use statistical analysis of system performance and

[20] Reporting on a ten-year planning horizon is observed in the "2017 Long-Term Reliability Assessment," NERC <https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf>

projected supply availability [e.g., forced outage rate ("FOR")] and simulate system behaviour to determine the resultant forecast system reliability. This provides an indication of the likelihood that all demand will be served. Deterministic analyses evaluate the contribution of individual system elements to overall system reliability. This provides the ability to test system resiliency in consideration of different contingencies or outage events. The use of differing, complementary methods offers a robust analysis of system adequacy. Based on the analysis conducted, it is recommended that supply adequacy continue to be assessed on the basis of both probabilistic and deterministic supply adequacy criteria.

From an energy perspective, Hydro completed an assessment of its ability to meet firm energy requirements in consideration of firm hydraulic energy sequences.[21]

1.3 Overview of the Resource Planning Process

Figure 2 is a flowchart that provides a visual representation of Hydro's resource planning process.

[21] Minimum storage targets are developed annually to provide guidance in the reliable operation of Newfoundland and Labrador Hydro's major reservoirs: Victoria, Meelpaeg, Long Pond, Cat Arm, and Hinds Lake. The minimum storage target is designed to show the minimum level of aggregate storage required such that if there was a repeat of Hydro's critical dry sequence, or other less severe sequence, Hydro's load can still be met through the use of the available hydraulic storage, maximum generation at Holyrood Thermal Generating Station ("Holyrood") and now firm imports. Hydro's long-term critical dry sequence is defined as January 1959 to March 1962 (39 months). Other dry periods are also examined during the derivation to ensure that no other shorter term historic dry sequence could result in insufficient storage.

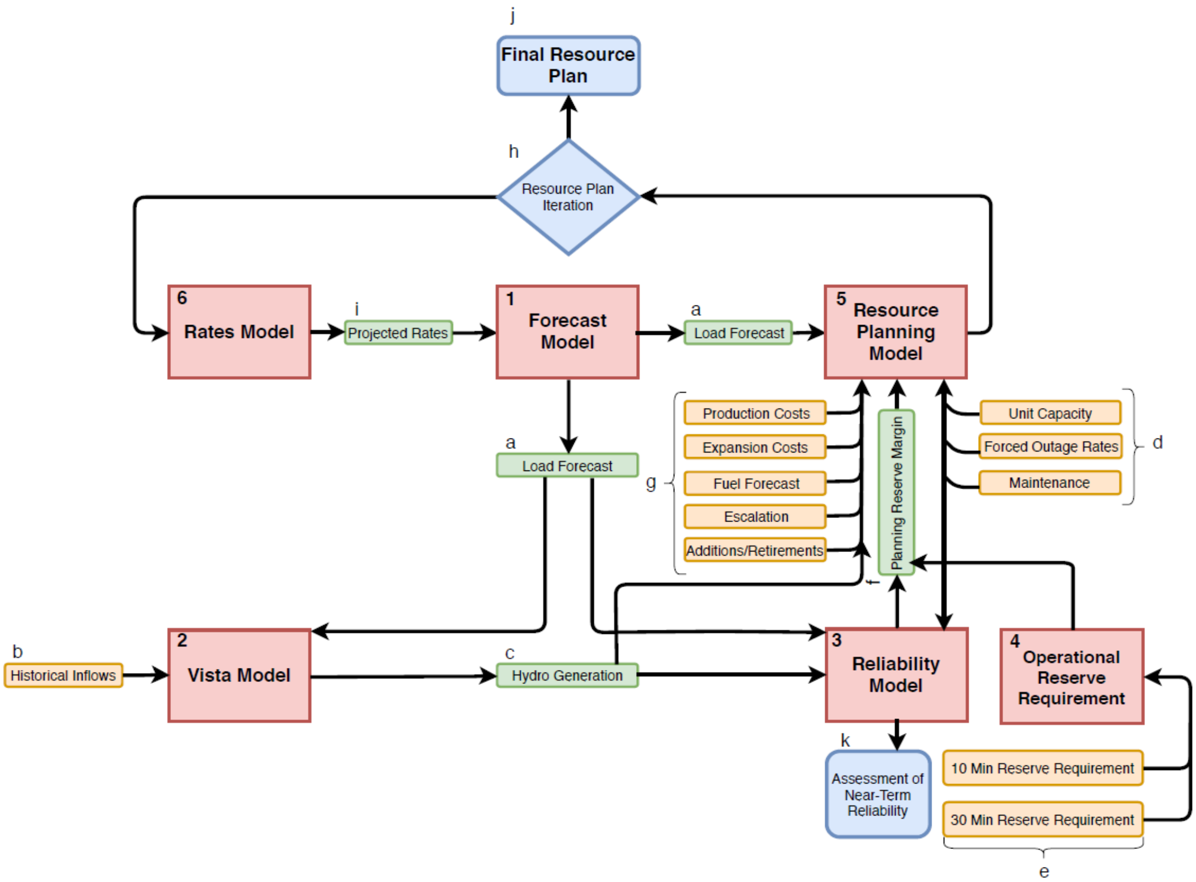

Figure 2: Resource Planning Process Flowchart

The process begins with development of the system load forecasts using Hydro's forecast models [1]. The load forecasts provide projections of system annual peak demand and annual energy requirements. Standalone load forecasts are prepared for both the IIS and LIS. These forecasts are then combined with consideration of the system coincidence factor[22] to provide a NLIS peak demand forecast. The provincial system forecast (i.e., the regional forecast) and the standalone forecasts for the IIS and the LIS are then used throughout the modelling process [a].

[22] Coincidence factor is a measure of the likelihood of independent systems peaking at the same time.

The energy requirements of the load forecasts [a] and the hydraulic record[b][23] are used by the Vista mode [2]l[24] to generate a forecast of average hydraulic generation [c].[25] The forecast of hydraulic generation [c] is then used in the reliability model, described below, to develop operating parameters for hydraulic generation.

The reliability model [3] is used to assess anticipated system reliability during the forecast period based on numerous parameters including unit and plant availability and reliability. It is used to determine the target planning reserve margin [f], that is, the quantity of reserve determined by the probabilistic assessment that must be held to satisfy reliability requirements. To do so, the reliability model considers the capacity requirements developed in the load forecast [b], the hydraulic generation forecast identified by Vista [c], and several key unit parameters focused on unit and plant availability and reliability [d], to accurately model anticipated system reliability. To ensure that the reliability model results are robust, there is a measure of uncertainty applied to the modelling inputs. These uncertainties are incorporated by modelling parameters probabilistically (e.g., the potential for variation in hydraulic generation at Muskrat Falls), introducing randomness (e.g., timing of unit forced outages), and/or modelling a specific uncertainty profile (e.g., the weather-driven load forecast uncertainty profile). Monte Carlo simulation techniques[26] are then used to simulate the probable range of operating scenarios to ensure the resultant planning reserve margin [f] is determined through understanding of the risk and uncertainty contained within the system.

The resource planning model [5] evaluates the existing supply capability against the load forecasts [a], in consideration of the reserve margin target [f] determined by the reliability model, identified operational reserve requirements, and energy requirements above the

[23] Hydro's modelled hydraulic record currently consists of sixty-seven years of hydraulic inflows.
[24] Vista DSS is a software program used by Hydro to provide medium- to long-term water storage and energy-generation management that guides water operations, hydrothermal generation, and energy transactions.
[25] Note that assessment of Hydro's ability to meet forecast customer and system energy requirements in consideration of the full hydraulic record is conducted in Vista.
[26] Monte Carlo simulation is a mathematical technique that employs multiple simulations of system parameters using random variables of defined distributions to generate potential different system outcomes.

existing hydraulic profiles [c], to determine when the system is resource deficient. These components [a],[c],[f] in combination with the unit parameters [d], and other system costs and financial components [g] form the inputs of Hydro's resource planning model. The resource planning model then determines the least-cost resource plan [h] which satisfies system reliability requirements. The least-cost resource plan is chosen from a number of identified resource options available to meet future system requirements. These resource options include renewable and non-renewable, and dispatchable and non-dispatchable resources that can be constructed, as well as the opportunity to offset required construction by investing in alternate technologies (e.g., customer demand management and alternate rate structures, and storage technologies such as batteries).

The resource plan [h] is then modelled in Hydro's long-term financial model to determine the impact, if any, of the required investment on customer rates [i]. As a commodity, the demand for electricity is elastic, meaning that electricity customers exhibit some sensitivity to price. Projected investment costs likely increase projected electricity rates, resulting in a decrease in forecast customer load requirements. This decrease can be material enough to then defer the timing of the required investment. The rate projection [i] associated with a resource plan [h] is used to determine if projected change in rates materially impact forecasted load requirements.

This begins an iterative process which concludes when the rate projection [i] resulting from the proposed least-cost resource plan [h] does not result in a change in load forecast that would alter the requirement for resources [b]. The final iteration of the resource plan then becomes the recommended resource plan [j], concluding the planning process. If resource additions are identified as part of the update filed annually with the Board, Hydro would begin the Regulatory process to advance the recommended resource plan.

1.4 Modifications Required to the Planning Process

Hydro's approach considered both reliability requirements and customer affordability

While the process described in Section 1.3 details Hydro's traditional approach to resource planning, the impact of rates following the in service of the Lower Churchill Project assets requires the approach to be modified to support development of additional information likely pertinent to the "Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs" ("Reference Question").[27] As the recovery of total costs of the Muskrat Falls Project is under review and any planning process can result in recommendations that can further increase system investment, Hydro has included information in this report to inform the impact of additional investment. To better understand the impact of the recommendations on total revenue requirement, a range of alternative load forecasts were considered to determine the resource additions required in each scenario and the resulting cost impact.

2 Reliability Criteria

NERC is a non-profit, self-regulating organization whose objective is to ensure adequate reliability of the bulk power system in North America

Many utilities throughout Canada and across North America have adopted reliability metrics that follow guidelines established by the NERC. NERC is a non-profit, self-regulating organization with an objective to ensure adequate reliability of the bulk power system in North America. NERC develops and enforces reliability standards,

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[27] "Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Costs," Newfoundland and Labrador Board of Commissioners of Public Utilities, Media Release, October 16, 2018 <http://www.pub.nf.ca/2018ratemitigation/notices/Media%20Release%20-%20Rate%20Mitigation%20Options%20and%20Impacts%20-%20FINAL%20-%202018-10-16.pdf>

including guidelines for long-term resource planning. The North American bulk power system is divided into eight regions, encompassing all of the United States and Canada, with the exception of Newfoundland and Labrador. The Maritimes area is included as one of the eight regions and is governed by the NPCC.[28]

As part of its integration work, Hydro has been working towards voluntary NERC compliance

Loss of load metrics help quantify the likelihood that a utility will not be able to meet its demand requirements at a point in time, considering numerous potential operating scenarios that can occur.[29] In other words, loss of load metrics evaluate the instances in which system demand exceeds the available generating capability. There are four generally accepted types of probabilistic metrics that system reliability is measured against: Loss of Load Probability ("LOLP"), Loss of Load Expectation ("LOLE"), Loss of Load Hours ("LOLH"), and Expected Unserved Energy ("EUE"). While interpretation of the measures varies across jurisdiction, definitions contemplated herein are consistent with NERC guidelines, which state: [30]

LOLP: *The probability of system daily peak or hourly demand exceeding available generating capability in a given study period.*

LOLE: *The expected number of days each year where available generation capacity is insufficient to serve the daily peak demand.*

LOLH: *Loss of Load Hours is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period (or the load duration curve) instead of using only the daily peak in the LOLE calculation.*

EUE: *A measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria.*

[28] NPCC is a regional entity division which operates under a delegation agreement with the NERC.
[29] Loss of Load refers to instances where some system load is not served.
[30] "Probabilistic Assessment Technical Guideline Document," NERC, August 2016 <https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf>

Since 2012, Hydro has used a combination of LOLH (probabilistic) threshold of 2.8 hours per year, operational (deterministic) reserve requirements of 240 MW, and energy criteria in its assessment of near-term resource adequacy.

3 Reliability Criteria Review

3.1 Pre-existing Planning Criteria

System supply investment to date has been based on previously established resource planning criteria, detailed as follows:

Capacity: The IIS should have sufficient generating capacity to satisfy a LOLH expectation target of not more than 2.8 hours per year.

Energy: The IIS should have sufficient generating capability to supply all of its firm energy requirements with firm system capability.

Additionally, Hydro maintained operational reserves of no less than 240 MW on the IIS. This 240 MW reserve margin provides the ability to meet current operational reserve requirements.[31]

IIS Pre-Existing Planning Criteria:

- **Capacity**
  - **2.8 LOLH**
- **Energy**
  - **Supply firm energy requirements with firm system capability**
- **Operational Reserves**
  - **240 MW**

[31] Operationally, the system requires the ability to withstand the loss of the single largest resource (typically the loss of Holyrood Unit 1 or 2, or Bay d’Espoir Unit 7) while maintaining an additional reserve of 70 MW.

The previous resource adequacy target of two outage days in ten years, or an LOLE of 0.2, was chosen at the time over the alternative criteria of one day in ten years, or an LOLE of 0.1, to decrease cost of meeting target. A change in software necessitated a benchmarking process to translate the LOLE to LOLH, at which point it was determined that the LOLE of 0.2 could be approximated as an LOLH of 2.8 hours per year. Note that the pre-existing criteria will continue to be applied until full integration of the Lower Churchill Project Assets (Planned Q3 2020).

With the new transmission interconnection to the North American grid, there is a need to better understand how reliability expectations compare to those of other interconnected utilities and the implications for reserve requirements and the resulting supply adequacy

3.2 Review of Other Utility Practices

As part of its review process, Hydro reviewed the practices of other utilities in determining resource adequacy, facilitated by Daymark Energy Advisors ("Daymark").

Daymark's review determined that, from a capacity planning perspective, most utilities employed probabilistic modelling techniques to satisfy loss of load expectation target of not exceeding 1 day in 10 years (LOLE=0.1)

Daymark also observed that while the adoption of the criteria itself prevailed in the industry, the method by which modelling and determination of supply adequacy was conducted is subjective and varies between utilities. Daymark also researched publicly available information on water flow and critical sequence modelling in other hydro-centric regions. A summary of Daymark's findings is found in Volume I, Attachment 2.

3.3 Proposed Reliability Criteria

In consideration of past practices, the review of utility practice, and the intention to voluntarily comply with NERC reliability standards, Hydro recommends modifications to both the probabilistic and deterministic capacity planning criteria. The system energy planning criteria is proposed to be extended to the entire NLIS.

Proposed Planning Criteria:

- **Capacity**
  - **Both 0.1 LOLE and operational reserve requirement**
- **Energy**
  - **Meet firm energy requirements with firm system capability**
- **Operational Reserves**
  - **296.5 MW**

3.3.1 Capacity Criteria

Probabilistic and deterministic assessments of resource adequacy post-interconnection have resulted in Hydro's recommendation to adopt the new capacity planning criteria outlined within this section. Since all criteria must be satisfied, the system will be evaluated on both probabilistic (i.e., violation of the 0.1 LOLE criteria) and deterministic (violation of the requirement to maintain sufficient operational reserves) criteria. Further, given the transmission constraint of the LIL as a source of supply to the Island, it is prudent to incorporate consideration of capacity dedicated to the IIS. If criteria had only been developed on a provincial basis, the addition of capacity in Labrador would improve the reserve margin without producing a decrease in the system LOLE due to the fact that it would not be possible to deliver that capacity to the Island, given the maximum transfer capacity of 900 MW across the LIL. If there is sufficient existing supply in Labrador to fully utilize the LIL, any additional capacity installed in Labrador will not improve reliability for the IIS region (i.e., as the transfer capability of the LIL will not increase, the addition of a source in the region will not increase IIS reliability). By adopting a separate requirement for the IIS, the planning process ensures that reliability in both the province and on the Island is in line with customer expectations.

3.3.1.1 *Proposed Probabilistic Capacity Planning Criterion*

Capacity: Both the Newfoundland and Labrador Interconnected System (region) and the Island Interconnected System (sub-region) should each have sufficient generating capacity to satisfy a LOLE target of not more than 0.1.

This planning criterion was determined following a probabilistic assessment of the impacts of capacity-based inputs on supply adequacy to determine an appropriate planning reserve margin. Detailed information on the development of the proposed planning reserve margin is found in Section 4.1.

3.3.1.2 *Operational Reserve Requirements*

Operating reserve refers to the system capability within a defined period of time to meet demand in case of disruption of supply (e.g., the trip of a generating unit, loss of a transmission line). The analysis also considered the deterministic compliance requirements as established by the NPCC. The NPCC requirements state that compliant utilities will ensure that: [32,33]

- *"Each Balancing Authority shall have* ***ten-minute reserve*** *available to it that is at least equal to its* ***first contingency loss."; and***
- *Each Balancing Authority shall have* ***thirty-minute reserve*** *available to it that is at least equal to one-half its* ***second contingency loss****."*

[32] The Balancing Authority is defined by NERC as the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
[33] "Regional Reliability Reference Directory # 5 Reserve," NPCC, October 11, 2012 <https://www.npcc.org/Standards/Directories/Directory_5-Full%20Member%20Approved%20clean%20-GJD%2020150330.pdf>

In the NLIS, Hydro considers the first contingency loss to be the loss of a generating unit at MFGS and the second contingency loss to be the loss of a second unit at MFGS. As such, as a Balancing Authority, Hydro will plan for the availability of the following operational reserves for the NLIS: [34,35]

Ten-minute reserves: Hydro shall have ten-minute reserve available to it at least equal to 197.5 MW to cover its first contingency loss, where the first contingency loss is the loss of a unit at the MFGS at winter firm plant output of 790 MW.

Thirty-minute reserves: Hydro shall have thirty-minute reserve available to it at least equal to 99 MW to cover one-half the magnitude of its second contingency loss (0.5 x 197.5 MW), where the second contingency loss is the loss of a unit at the MFGS at winter firm plant output of 790 MW.

In addition to providing guidance on the amount of operational reserve that must be held by a Balancing Authority, the NPCC guidelines also have requirements on the amount of reserve which must be synchronized to the grid.[36]

Deterministic Criteria:

- **1st contingency loss = 197.5 MW**
- **2nd contingency loss = 99 MW**
- **Total operational reserve requirement = 296.5 MW**

[34] For additional information about the winter firm plant output of the MFGS, please refer to Section 4.2.2.1.
[35] This is based on the per unit contribution to the firm plant output of the MFGS (790 MW).
[36] Synchronized reserve is also commonly referred to as spinning reserve. Spinning reserve refers to the unloaded generating capacity connected to the system that is not actively meeting customer requirements.

The guidelines state: [37]

> ***"Requirements for synchronized reserve available within ten minutes for NPCC Balancing Authorities shall be based on demonstrated performance. The requirements shall not be more than 100% or less than 25% of the ten-minute reserve requirement."***

The above means that a utility must have a minimum of 25% of the ten-minute reserve quantity synchronized to the system, with the remaining ten-minute reserve fully available within the required ten minutes. Further, the standard notes the requirement for synchronized reserve available between the minimum and maximum acceptable requirements will be "*adjusted based upon the Balancing Authority's past performance in returning its Area Control Error ("ACE") to pre-contingency values, or to zero, within fifteen minutes following loss of resource*." [38] To ensure these operational requirements can be met these requirements are included in the resource planning process. For more detail on how operational reserves are considered in the long-term planning process, refer to Volume III, Section 6.1.1 this Study.

In consideration of the operational reserve requirements, a total operational reserve margin of at least 296.5 MW must be available for the NLIS.[39]

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[37] "Regional Reliability Reference Directory # 5 Reserve," NPCC; October 11, 2012 <https://www.npcc.org/Standards/Directories/Directory_5-Full%20Member%20Approved%20clean%20-GJD%2020150330.pdf>

[38] Ibid.

[39] The addition of the ten minute reserve requirement (197.5 MW) and the thirty minute reserve requirement (99 MW) yields a reserve requirement of 296.5 MW.

3.3.1.3 *Case Analysis: Include the P90 Peak Demand Forecast in Supply Planning Analysis*

The forecast variability of the P90 peak demand was confirmed independently to be 58.9 MW. Hydro previously considered it to be 60 MW.

Hydro's probabilistic assessment of resource adequacy includes a load forecast uncertainty parameter that allows consideration of the full range of forecast variation driven by weather.[40] This ensures that when evaluating its P50 forecast,[41] the impact that weather variability can have on the expected peak is considered through application of the load forecast uncertainty multiplier. This treatment is consistent with practices observed across industry.[42] Note that the resultant determination of planning reserve margin includes consideration of load variability resulting from all weather conditions (i.e., P01 through P99), with the results applied as a variation from the mean forecast value (i.e., P50). This new method for assessing load forecast uncertainty increases the conservatism embedded in forecast modelling compared to modelling only the P50 and P90 discretely.

In its September 29, 2016 correspondence to Hydro, titled "Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System - Directions further to the Board's Phase One Report," the Board directed use of the P90 weather variable as the base case in all reporting to the Board for supply planning decisions related to the IIS.[43] To determine the P90 peak demand forecast, the magnitude of the variability associated with 90% of weather

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[40] For more detail on the load forecast uncertainty included in Hydro's Reliability Model, refer to Section 4.2.1.1.
[41] A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50% of the time and above 50% of the time (i.e., the average forecast). A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90% of the time and above 10% of the time.
[42] Refer to Volume I, Attachment 3 for additional detail.
[43] Newfoundland and Labrador Board of Commissioners of Public Utilities, "Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System – Directions further to the Board's Phase One Report," letter, October 13, 2016 <http://www.pub.nl.ca/applications/IslandInterconnectedSystem/files/reports/To%20NLH%20-%20Directions%20further%20to%20the%20Boards%20Phase%20One%20Report%20-%202016-10-13.pdf>

conditions must be determined. Daymark independently validated that the expected variation associated with the P90 peak demand was +58.9 MW. This is consistent with the P90 adjustment of 60 MW previously determined by Hydro.

Hydro recognizes the value in considering the variability associated with the P90 condition, particularly from a risk awareness and preparedness perspective; however, Hydro does not believe that planning to meet a P90 peak demand forecast is in the best interests of customers at this time. To consider the P90 forecast, the 60 MW requirement would be added to the peak demand forecast. By adding this requirement to the peak demand forecast and then considering reserve margin requirements, the incremental requirement for capacity is not only increased by 60 MW, but actually increased by 60 MW plus 60 MW multiplied by the reserve margin. As such, if the desired reserve margin is 13%, planning for the P90 peak demand forecast will increase system requirements by 67.8 MW over the P50 peak demand forecast [i.e., a 60 MW increase in base forecast and a 7.8 MW (60 MW × 13%) increase associated with the reserve margin.]

At the time of the Board's previous direction, in consideration of the isolated nature of the IIS, the emerging reliability issues experienced at Holyrood, and the existing planning criteria of 2.8 LOLH, Hydro agrees increased conservatism was appropriate. Following interconnection to the North American grid and in consideration of the increased reliability offered by adoption of the 0.1 LOLE planning criteria and use of load forecast uncertainty in establishing the planning reserve margin, Hydro believes the P50 peak demand forecast is most suited to planning decisions. Further, when conducting NERC Resource Adequacy assessments, NERC requires utilities to report total internal demand projections are based on normal weather (50/50 distribution), provided on a coincident basis for most assessment areas.

Hydro proposes the P90 peak demand forecast continue to be evaluated from a planning perspective, but that resource additions are planned on a P50 peak demand forecast basis.

Hydro will continue to report the P90 peak demand forecast to the Board as part of its resource planning process. Hydro will also track and report on the frequency of weather conditions that occur between P50 and P90 expectations and above P90 to monitor when or whether changes are necessary.

3.3.2 Energy Criteria

A review of the system energy capability and forecast requirements have resulted in the recommendation to extend the existing energy planning criteria to cover the entire NLIS, as follows:

Energy:	The NLIS should have sufficient generating capability to supply all of its firm energy requirements with firm system capability.

4 Study Methodology

4.1 Modelling Approach

The study analysis, including the development of the PLEXOS® model,[44] was conducted in accordance with the most recent version of the NERC "Probabilistic Assessment Technical Guideline Document"[45] and the NERC "Reliability Assessment Guidebook"[46] to ensure alignment with industry accepted practice.

[44] For additional information as to why Hydro migrated from the Strategist Modelling Platform to the PLEXOS® Modelling Platform, see Volume I, Attachment 4 "Migration to the PLEXOS® Modelling Platform"

[45] "Probabilistic Assessment Technical Guideline Document," NERC, August 2016 <https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf>

[46] "Reliability Assessment Guidebook," NERC, August 2012, Version 3.1 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf>

For the analysis and model development, Hydro utilized the NERC "Probabilistic Assessment Technical Guideline Document" and the NERC "Reliability Assessment Guidebook" to ensure alignment with accepted industry practice

The "Probabilistic Assessment Technical Guideline Document" provides modelling *"practices, requirements and recommendations needed to perform high-quality probabilistic resource adequacy assessments."*[47] The "Probabilistic Assessment Technical Guideline Document" provides a more granular view of resource adequacy, focusing on monthly and annual LOLH and EUE reporting, meant to enhance the annual view provided by long-term resource adequacy analyses. The "Reliability Assessment Guidebook" provides a set of guidelines for the assessment of resource adequacy and planning to meet the reliability expectations of consumers. Processes and guidelines from both documents were used to inform the planning process.

The planning reserve margin that exactly satisfies established planning criteria (0.1 LOLE) is used in Hydro's long term resource planning process

While long-term investment requirements will be identified using the planning reserve margin process, this process will be complemented by the evaluation of near-term supply adequacy as identified required investments progress from a longer term planning horizon to the near-term planning horizon. By using this methodology, the potential for resource shortfalls will be identified well in advance, leaving adequate time to plan and construct or secure the least-cost

[47] "Probabilistic Assessment Technical Guideline Document," NERC, August 2016 <https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf>

resource option. The granular near-term view provides insight into the impact of seasonal load and generation variations on supply events. This can be used to further inform the decision on which resource options are best suited to meet evolving system requirements.

The NERC "Reliability Assessment Guidebook" notes that typically, upon completion of probabilistic adequacy assessments, the results are translated into a planning reserve margin. This planning reserve margin can then be used as a reliability metric to evaluate the system's resource adequacy. A detailed hourly system model ("the Reliability Model") using Monte Carlo simulation was implemented in PLEXOS® to determine an appropriate planning reserve margin to satisfy the proposed reliability criteria,[48] consistent with practices in other jurisdictions.

The planning reserve margin is used as a reliability metric to evaluate the system's resource adequacy

As capacity additions and retirements occur, the relationship between the probabilistic measure being used and the reserve margin that is used as proxy changes, particularly if the attributes of the resources being considered are materially different. For example, the replacement of Holyrood, which has a planning Derated Adjusted Forced Outage Rate ("DAFOR")[49] between 15% and 20%, with the MFGS, with its planning DAFOR of 1.9%, will have a significant impact on the required planning reserve margin, as the increased reliability reduces the actual planning reserve margin required. Further, the relationship is also dependent on the size of the resource being added to the resource mix. For example, the addition of multiple smaller units will improve the LOLE of the system more than the addition of a larger unit with an equivalent capacity, despite having the same effect on the reserve margin.

[48] Hydro's proposed reliability criteria are introduced in Section 3.3.
[49] Derated Adjusted Forced Outage Rate measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating ("MCR") due to forced outages.

To ensure incremental investment is made prudently, it is important to select a representative year that most closely represents anticipated long-term system conditions. The year 2026 was selected as the representative year since at that time, all currently planned additions and retirements are expected to have occurred and the delivery of the supplemental energy requirement is complete.[50,51]

Hydro notes that the selection of the representative year is for the purpose of setting the criteria only. Hydro's forecast reserve margin will be reported on an annual basis for all years within the study period, with these results then compared against the planning reserve margin to determine if additional resources are required.

To determine the planning reserve margin in the representative year, an assessment must be completed that satisfies the specified target. An LOLE of 0.1 was chosen for the desired reliability as this is generally accepted as industry standard and compliance with the LOLE of 0.1 metric was well observed in the review of the practices of other utilities. Simulation is then used to determine the reserve margin that corresponds to the LOLE reliability criteria. This reserve margin becomes the utility's planning reserve margin (i.e., the reserve margin at which the utility exactly satisfies its established planning criteria). This planning reserve margin is then used in the utility's long-term resource planning process. The resultant target planning reserve margin is presented in Section 5. Further information on the resulting proposed long-term resource plan is found in Volume III - Long-term Resource Plan.

[50] Supplemental Energy refers to an additional firm energy commitment to supply energy to Nova Scotia during the first five years of production at the MFGS as part of the Amended and Restated Energy and Capacity Agreement.
[51] While 2026 was chosen as the representative year, Hydro also evaluated results using other years in the study period and determined that the planning reserve margin results were not materially different.

4.2 Modelling Assumptions

Figure 3 is a representation of the NLIS model. It is a simplified display of the way in which each region is connected within the provincial zone and to the external markets, Quebec and Nova Scotia with arrows indicating the possible flow of energy.

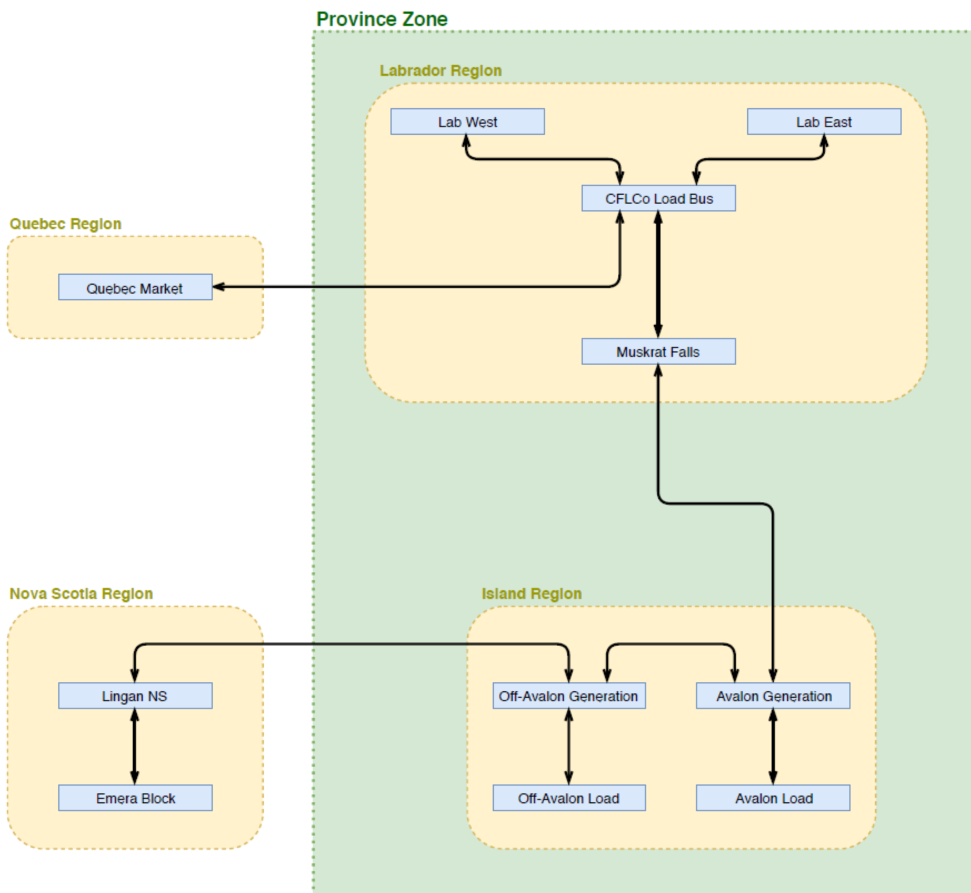


Figure 3: Newfoundland and Labrador Model Topography

The following section discusses the methodology surrounding development of each component of the NLIS in the Reliability Model including the load modelling, capacity modelling by asset class, transmission modelling, and market modelling. The inputs and assumptions implemented in the model are discussed in detail within the following sub-sections.

Key Inputs into the Reliability Model:

- Load Modelling
- Capacity Modelling
- Thermal and Gas Turbines
- Variable Energy Resources
- Capacity Transfers: Imports and Exports
- Transmission Modelling
- Emergency Operating Procedures

4.2.1 Load Modelling

The purpose of load forecasting is to project electric power demand and energy requirements through future periods. It is a key input to the resource planning process, which ensures sufficient resources are available consistent with applied reliability standards. The load forecast is segmented by the IIS and LIS, and rural isolated systems, as well as by utility load (i.e., domestic and general service loads of Newfoundland Power and Hydro) and industrial load (i.e., larger direct customers of Hydro such as Corner Brook Pulp & Paper Ltd., North Atlantic Refining Ltd., Vale, and Iron Ore Company of Canada). The load forecast process entails translating a long-term economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems. The load forecasts for the IIS and LIS were prepared during the spring and summer of 2018.[52]

4.2.1.1 *Load Modelling: Load Forecast Uncertainty*

Load forecast uncertainty models how a system's peak load can vary from the forecast peak load by providing an uncertainty range to the load forecast. A load forecast uncertainty parameter[53] is applied against the expected peak demand, that is, the P50 peak demand

[52] Hydro predicts future load requirements for the IIS primarily through econometric modelling techniques and large industrial customer input. Future load requirements for the LIS are primarily through historical trend analysis and large industrial customer input.

[53] Load Forecast Uncertainty is a multiplier representing the potential variance in annual peak demands. Its value is based on a distribution of expected values of load based upon an analysis of the weather sensitivity of peak loads.

forecast for the area.[54] Both potential economic variability and weather variability uncertainty have been incorporated in the planning process. A range of economic conditions were considered in the development of long-term resource plans, while probabilistic modelling of weather variability was considered in setting the planning reserve margin.

4.2.1.2 *Weather Variability and Load Forecast Uncertainty*

Daymark analyzed the impact of historical weather variability on peak demand forecasts for the IIS and LIS. The method utilized two steps:

1) Developing a regression-estimated relationship between weather and peak demand; and
2) Producing future weather values by utilizing a probabilistic distribution.

Daymark developed an estimate of the impact of representative historical weather variability on peak demand (MW) forecasts for the IIS as weather is a critical driver of peak demand and thus impacts reliability. The method explicitly accounts for such weather variability using Monte Carlo simulation.[55] These future possible weather-related values and the historic relationship between peak demand and the weather variable that was estimated using industry standard regression models, were then used to quantify the additive peak demand component associated with weather variability.

Figure 4shows the distribution of additional peak demand as a result of the weather variability in the Island's peak load forecast of 2027.[56] The distribution is based on 10,000 weather simulations generated by a Monte Carlo simulation of the variability observed in historical

[54] "Reliability Assessment Guidebook," NERC, August 2012, Version 3.1 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf>

[55] Specifically, probabilistic models were used to generate 10,000 possible future wind chill values for each year of the load forecast.

[56] The horizontal axis represents the range of additional peak demand resulting from different wind chill values generated from the simulation. The vertical axis is the number of additional peak demand levels from 10,000 possible values falling in each range.

weather values. The figure also includes a vertical line within the distribution to represent the P90 value of peak load uncertainty associated with weather variability. For the 2027 peak demand forecast, Daymark found the P90 value associated with weather related peak demand uncertainty to be 58.9 MW. This compares to the 60 MW value that Hydro has been using to account for weather related peak demand forecast uncertainty in its previous modelling. The method used to account for the impact of weather variability for the reliability assessment is consistent with probabilistic methods used by NERC-compliant regions.

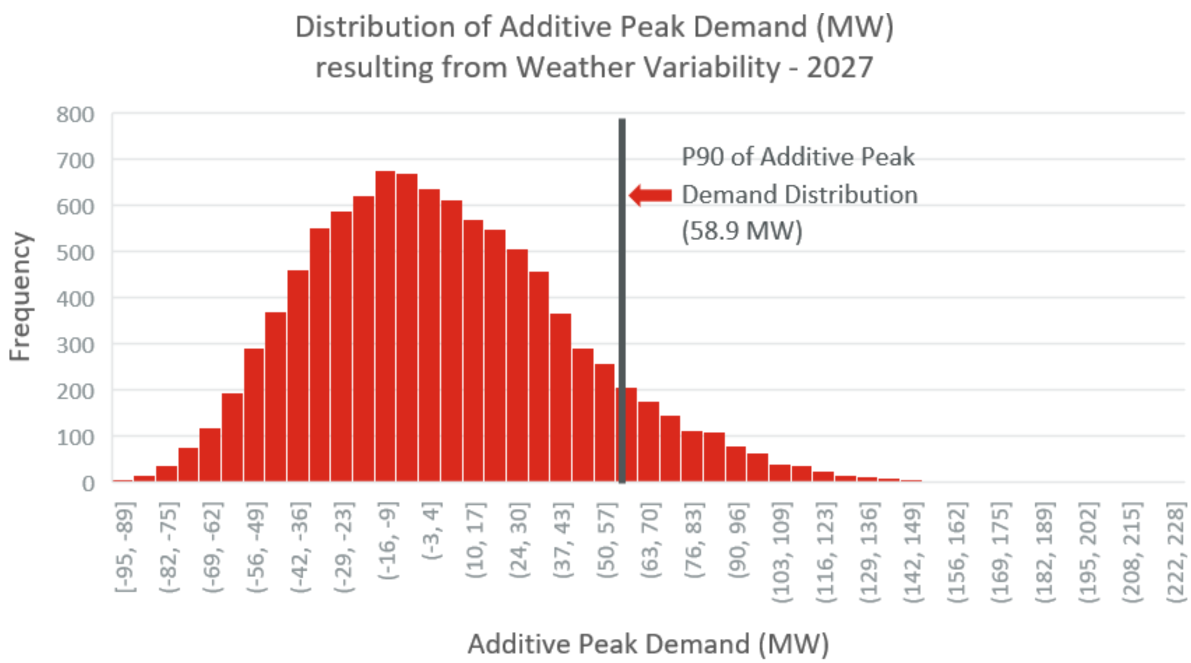


Figure 4: Results of Weather-Driven Load Forecast Uncertainty Analysis

The process used by Daymark to estimate the impact of weather variability in the peak demand forecast is outlined in detail in Volume I, Attachment 3.

The weather variability load forecast uncertainty was modeled probabilistically using the distribution provided by Daymark's analysis. This embeds the consideration of the full range of forecast weather uncertainty in Hydro's planning process. By considering weather variability in this manner, variations in peak demand associated with differing weather conditions are considered at the appropriate likelihood of occurrence, offering a significant improvement over considering only discrete P50 and P90 forecasts.

4.2.1.3 *Load Modelling: Newfoundland and Labrador Interconnected System Coincidence*

To determine a NLIS demand forecast it was necessary to assess the coincidence of the IIS and the LIS. The coincidence factor provides a measure of the likelihood of the independent systems peaking at the same time. Figure 5 provides a visual representation of coincidence factor. Given that the systems were not previously connected to each other, the coincidence between the IIS and LIS was not measured and reported in the past. For this Study, a calculation of a coincidence factor between the two systems based on available peak demand records covering the period from 2006 to 2018 was prepared.

The coincidence factor provides a measure of how likely the IIS and LIS are peaking at the same time

The assessed coincidence factors in 2018 for NLIS peak have been estimated at 99.2% for the IIS peak demand and 95.3% for the LIS peak demand. This means that at the time of the forecast NLIS Peak, the IIS is forecast to be 99.2% of its forecast peak demand and the LIS is at 95.3% of its forecast peak demand.

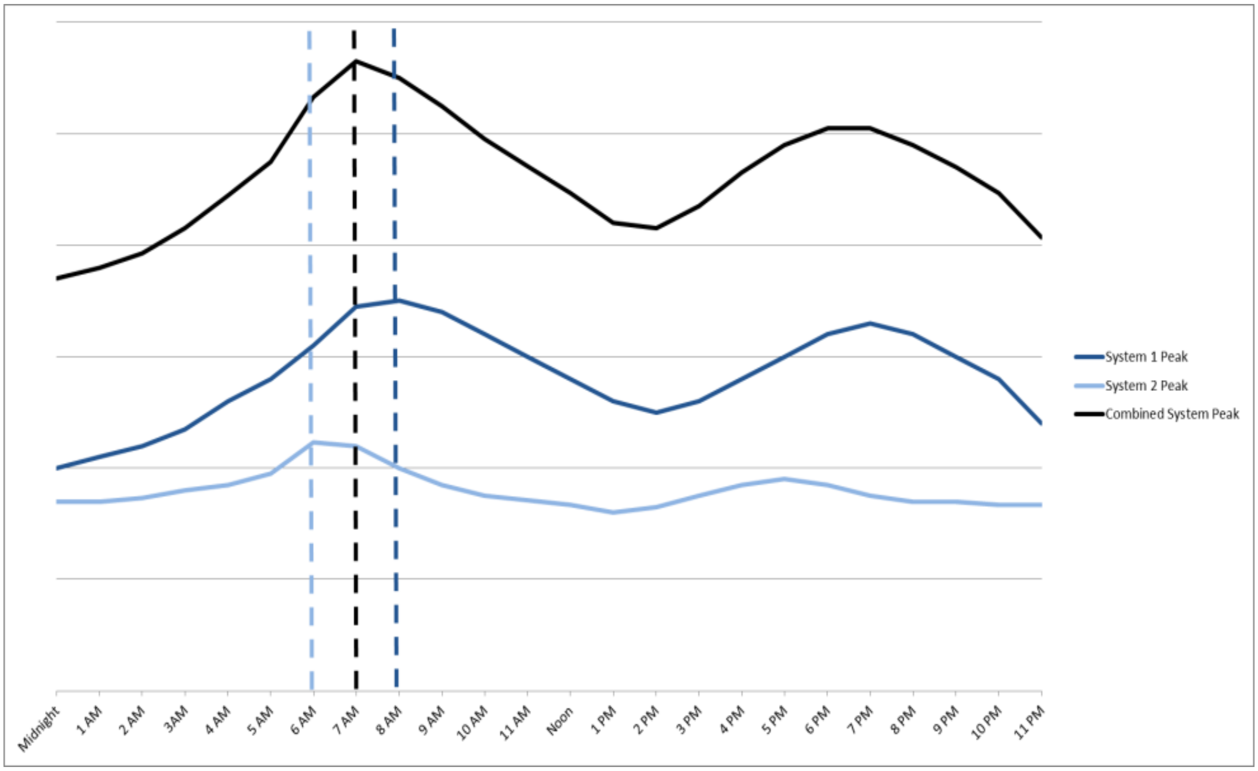


Figure 5: Visual Representation of Coincidence Factor

4.2.1.4 *Load Modelling: Demand-Side Management*

Controllable demand response programs are modeled explicitly in accordance with NERC's "Probabilistic Assessment Technical Guideline Document." NERC defines a demand response resource as "*a Load or aggregation of Loads capable of measurably and verifiably providing a reduction in load as seen by the retail delivery point.*"[57] As such, per the definition, the current capacity assistance agreement with Corner Brook Pulp and Paper, in effect through 2022, meets the definition of demand response resource and should be modeled explicitly in the Reliability Model.[58] All contracted parameters, including frequency, duration, and total consumption have been incorporated in the assessment. Following 2022, it is assumed that the requirement for a capacity assistance agreement will be re-evaluated as a result of the interconnection of the

[57] "Demand Response Availability Data System Definitions," NERC, March 2014 <https://www.nerc.com/pa/RAPA/dads/Documents/DADS%20System%20Definitions.pdf>

[58] Capacity assistance refers to curtailable loads and emergency customer generation that are under contract. Capacity assistance agreements are generally restricted in terms of frequency, duration and annual usage.

system. The Reliability Model does not include the agreement following its expiration in 2022. It is possible the same amount of assistance could be provided long-term if a requirement is identified through the assessment of resource adequacy and should the parties reach agreeable terms, subject to approval by the Board.

Refer to Volume II, "Near-Term Reliability Report" for details regarding the method by which existing capacity assistance agreements are modelled in the near term.

4.2.2 Capacity Modelling

To ensure accurate modelling of its supply resources, Hydro incorporated detailed modeling of its capacity resources and power purchase agreements, incorporating probabilistic analysis. The following sections detail the methodology Hydro used in modelling these resources. Hydro confirmed with Newfoundland Power that the latter's corporate plan does not currently include additions or retirements that would materially impact Hydro's resource planning analysis.

4.2.2.1 *Capacity Modelling: Hydroelectric Generation*

The energy profiles and all associated restrictions on hydraulic generation values used in PLEXOS® are based on anticipated average hydraulic production, generated by the Integrated System Vista model.

Typical annual maintenance is included in the Vista model, which is then optimized for each unit. The FOR is captured in the PLEXOS® model by using a random outage profile for each of the runs of the Monte Carlo analysis.

The majority of the generators owned by Hydro are hydroelectric and therefore have limitations on the amount of annual energy available. Operation of each of Hydro's reservoirs is performed in accordance with Hydro's "Major Reservoir Operations Manual." Tables 1 and 2 provide information on the capability of the hydraulic generating fleet.

Table 1: Capacity of Modelled Hydraulic Generating Units

Hydraulic Unit	Installed Capacity (MW)	Gross Continuous Unit Rating (MW)
Muskrat Falls		
Unit 1	206	197.5
Unit 2	206	197.5
Unit 3	206	197.5
Unit 4	206	197.5
Total Muskrat Falls Plant [59]	*824*	*790*
Bay d'Espoir		
Unit 1	76.5	76.5
Unit 2	76.5	76.5
Unit 3	76.5	76.5
Unit 4	76.5	76.5
Unit 5	76.5	76.5
Unit 6	76.5	76.5
Unit 7	154.4	154.4
Total Bay d'Espoir Plant	*613.4*	*613.4*
Cat Arm		
Unit 1	68.5	67.0
Unit 2	68.5	67.0
Total Cat Arm Plant	*137.0*	*134.0*
Other Hydro		
Hinds Lake	75.0	75.0
Granite Canal	40.0	40.0
Paradise River	8.0	8.0
Upper Salmon	84.0	84.0
Rattle Brook	4.0	0.0
Nalcor Energy Exploits	95.6	63.0
Star Lake	18.0	18.0
Total Other Hydro	*324.6*	*288.0*
Total Hydraulic Generation	**1,899.0**	**1,825.4**

[59] Quantity reported at Muskrat Falls.

Table 2: Energy Capability of Modelled Island Hydraulic Facilities

Hydraulic Facilities	Firm (GWh)	Average (GWh)[60]
Bay d'Espoir	2,272	2,650
Cat Arm	678	755
Hinds Lake	290	354
Granite Canal	191	246
Paradise River	33	35
Upper Salmon	492	556
Exploits	547	615
Star Lake	87	141
Total Hydraulic Generation	**4,590**	**5,352**

The units have been grouped into three categories for the purposes of modelling; units with storage capacities, units with smaller storage or run-of-river units, and units at Muskrat Falls. The approach to modelling these units is discussed in detail in the following sections.

4.2.2.2 *Hydro Units with Storage Capacities*

Hydro units with storage capacities (i.e., Bay d'Espoir, Granite Canal, Upper Salmon, Cat Arm, Hinds Lake, Exploits, Star Lake) are assumed to be able to produce at the plant rated capacities in any given hour. Seasonal restrictions, particularly winter capacity restrictions, are modelled for the Exploits system as the facility is particularly susceptible to frazil icing.[61] Hydro has undertaken a number of improvements in detection systems and operational procedures to mitigate unit unavailability resulting from frazil icing conditions. [62]

[60] Based on energy presented in Hydro's "2017 General Rate Application."
[61] Frazil ice is soft or amorphous ice formed by the accumulations of ice crystals in water that is too turbulent to freeze solid. This type of ice accumulates at plant intakes limiting the area in which water can pass through, impacting the amount of water that can be drawn into the plant and, thereby, reducing the generating unit capability.
[62] "Near-Term Generation Adequacy Report," Hydro, May 2018, detailed a number of such improvements including: (1) closely monitoring environmental conditions; (2) responding to trashrack differential alarms; (3) optimizing unit dispatch to allow solid ice cover to form; and (4) the installation of a system to remotely activate the frazil ice bubbler at Granite Canal. During the 2017-2018 winter operating season Hydro experienced one outage due to frazil ice.

4.2.2.3 *Hydro Units with Small Storage Capacities*

For the smaller units with limited storage capacities (i.e., Rattle Brook and Paradise River) the energy limitation is modelled as a daily constraint. To model appropriately, these units were given a daily energy limit that varies by month. The daily energy limit is based on the monthly energy output of the Vista Model.

Newfoundland Power's sites are modelled as 22 sites with characteristics and input hydrology that result in a reasonable estimate of its generation. Deer Lake Power's plant on Grand Lake is modelled to a level of detail similar to that of Hydro's system.

Muskrat Falls

The Muskrat Falls development has a nominal plant rating of 824 MW (i.e., four units, each rated to 206 MW), based on rated head conditions. During certain river operating conditions, the plant will be able to produce more or less power than 824 MW. These operating conditions affect the water elevation at the water intakes to the units and the water outlet, or the tailwater, elevation.

A projected relationship between the tailwater level and water flow through the plant has been developed, which is referred to as the tailwater rating curve. A component of the river operating condition that can affect the tailwater rating curve is the winter ice cover in the river downstream of the plant, which can impact the plant output.[63] This resulted in two sets of tailwater rating curves for the plant; one for open water and one for the period of ice cover.[64]

[63] The study to determine the tailwater rating curves used historic river water measurement data to estimate the relationship once the plant is in operation. Conservative estimates were used, which will be adjusted as necessary with actual measurements when the plant is in operation.

[64] Examples of important factors which can influence the amount of ice cover include; water, air temperature, ice roughness, active alluvial bed, etc. The winter water temperature may increase due to the higher water depth upstream of the plant as result of the creation of the forebay and due to the thermodynamic affect of the production of power in the plant. In 2016, the river was diverted through the spillway and during winter 2017/2018 the ice regime downstream of the plant has been changed (no ice dam).

When these estimated ice cover tailwater rating curves were applied to the plant production models, the maximum plant output during the winter was restricted to 790 MW.

Data has been collected and analyzed to determine whether adjustments can be made to the projected tailwater rating curves. While the new data does show that for a given flow the tailwater levels are in the lower range of the predicted relationship there is not yet sufficient data to verify this will be a long-term trend warranting a change to the curves. It is therefore recommended, until further operating data is obtained with the dam and plant in place, that the winter maximum output of 790 MW derived from the predicted tailwater curves be used in planning studies. This operating restriction has been incorporated in the Reliability Model.

The average expected annual generation from Muskrat Falls is 4.9 TWh. The firm energy estimate is 4.5 TWh. The potential for variability across potential inflow scenarios is incorporated by modelling the energy limitation of the Muskrat Falls plant probabilistically. This approach allows the model to consider both the daily and seasonal variations in flow, including low flow.

<u>Annual Generation Schedule</u>

Results of long-term monthly modelling of the NLIS were used to derive the average monthly energy expected from Muskrat Falls.

<u>Hourly Generation Schedules</u>

The characteristics of the Muskrat Falls facility provides very little storage with which to regulate inflows. Approximately 75% of Muskrat Falls inflows are from releases from the Upper Churchill and 25% are local inflows to the Churchill River between Churchill Falls and Muskrat Falls. In 2013, an analysis was undertaken to assess the travel time and degree of attenuation of outflows from Churchill Falls to Muskrat Falls and the degree to which Muskrat Falls generation could be shaped within the day. The modelling provided some indication of how the daily generation could vary by hour. Five hourly hydrologic sequences were evaluated for a one-year period.

The results of this analysis were used to determine the day-to-day variation in Muskrat Falls generation from the monthly mean. The monthly mean was calculated for each day in the five-year study period, and from this, the daily variation from the mean was calculated. This was used to develop a statistical profile of the daily variations in generation at Muskrat Falls.

4.2.2.4 *Capacity Modelling: Thermal and Gas Turbines*

Following the in-service of MFGS, Holyrood is planned to be retired in 2021 from generation mode, with one unit remaining operational in synchronous condenser mode. Further, as detailed in Hydro's "2019 Capital Budget Application," the Hardwoods and Stephenville gas turbines ("GTs") will be considered for retirement in 2021. All other thermal resources and GTs are assumed to be available at maximum capacity. Table 3 provides information on the capability of the thermal resources.

Table 3: Capability of Thermal Generating Units (2022 and beyond)

Thermal Generating Units	Installed Capacity (MW)	Gross Continuous Unit Rating (MW)
Gas Turbine		
Happy Valley GT	25.0	25.0
Hardwoods GT	50.0	50.0
Holyrood GT	123.5	123.5
Stephenville GT	50.0	50.0
Total Gas Turbine	*248.5*	*248.5*
Diesel		
Hawkes Bay Diesel Plant	5.0	5.0
Holyrood Diesels	12.0	8.5
St. Anthony Diesel Plant	9.7	9.7
Total Diesel	*26.7*	*24.7*
Total Thermal	**275.2**	**273.2**

Each unit is modelled as a generator with the respective historical average annual maintenance outage schedule factored into the generation profile. No seasonal restrictions have been placed on the thermal units or GTs in the model.

The Reliability Model includes probabilistic modelling of forced outages; the FOR methodology document is found in Volume I, Attachment 5.

4.2.3 Variable Energy Resources

4.2.3.1 *Variable Energy Resources: Wind Generation*

Hydro currently has power purchase agreements with two interconnected wind farms[65] on the IIS with a combined capacity of 54 MW. Wind generation is an intermittent, non-dispatchable resource, meaning its output cannot be easily varied like a conventional thermal resource as the output is dependent on the available wind speed. Production can also be challenging in times of very low or very high wind speeds. Low wind speeds may not reach the cut in speed required for the turbines to produce energy. Conversely, if wind speeds are too high, turbines may reach cut out speed, at which the turbines will shut down to prevent damage.

Previously, under the Isolated Island System, Hydro had not relied upon wind farms as contributing to the system's firm capacity

Previously, under the Isolated Island System, wind farms were not relied upon as a reliable contribution to the islands firm capacity from a long-term planning basis. This meant that wind generation was considered purely energy on a planning basis. Given the interconnection to the North American grid, as part of its Reliability Model, Hydro re-evaluated the contribution of wind generation to system capacity by conducting an effective load carrying capability ("ELCC")

[65] Wind farms in Fermeuse (27 MW) and St. Lawrence (27 MW).

study, an approach commonly used by other utilities. The results of that study informed the planning process by demonstrating the amount of wind generation that can be considered available on peak based on system production data.

The Effective Load Carrying Capability study was used to determine a capacity contribution of 22% for existing wind generation

An analysis was completed on the generation data from Fermeuse and St. Lawrence from in-service to present. The production data from these facilities implicitly includes the impacts of maintenance, forced outages, and unavailability due to both excessive and insufficient wind. From this data a probability distribution function was developed for each plant. To accurately model seasonal variations, a separate profile was developed for the winter season (i.e., December to March) and the non-winter season (i.e., April to November). For each run of the Monte Carlo analysis an hourly profile was randomly generated using the probability function. The ELCC study determined that the capacity contribution of the wind generation was 22% or approximately 6 MW of firm capacity per wind farm, which was included in the model.[66]

To ensure that the analysis is aligned with other industry practices, Daymark researched the method by which other utilities are modelling wind resources for reliability metric calculations and determined that the wind resource percentage contribution varies widely. In the summer, this contribution percentage ranges from 5% to 36% across regions, with the average percentage equaling close to 20%. In winter, the wind resource contribution percentage ranges from 0% to 30%, with the average percentage reaching approximately 16%.[67]

[66] A detailed description of the study can be found in Volume I, Attachment 6.
[67] Refer to Volume I, Attachment 2 "Resource Adequacy Criteria," Daymark, July 3, 2018, p. 3.

Incorporating the reliability value of wind in its Reliability Model better aligns with the practices of other utilities in Canada and industry best practices. While the 22% proposed is slightly higher than the 20% observed across industry, Hydro is comfortable using the 22% given the relatively low penetration of wind generating facilities on the NLIS (i.e., approximately 2.5% of total IIS supply) and the strength of the wind regime in Newfoundland and Labrador. The relationship between wind generation and the system will be assessed on an ongoing basis as part of resource adequacy assessments.

Following NERC standard practice, only firm imports and exports are considered

4.2.4 Capacity Transfers: Imports and Exports

In the Reliability Model only firm imports and exports are considered. This follows NERC standard practice, implemented to ensure capacity is not double counted between jurisdictions. Exports are added as a load and imports are treated as a reduction in load. The contractual requirements are used to derive an hourly profile for the exports or imports.

There are two commitments for firm exports; a commitment for firm capacity (the "Nova Scotia Block"), and a commitment for firm energy (the "Supplemental Energy"). The Nova Scotia Block is a firm commitment of 980 GWh, to be supplied from the MFGS on peak. This commitment begins with the availability of the third unit at Muskrat Falls, currently scheduled for the third quarter of 2020. There is also a commitment to supply additional firm energy to Nova Scotia during the first five years of production at the MFGS as part of the Amended and Restated Energy and Capacity Agreement. Hydro does not currently have firm import contracts in place, although the possibility could exist at some point in the future.[68] This is a conservative approach to maintaining the adequacy of provincial supply.

[68] Once Hydro has greater experience in market transactions it may be reasonable to reconsider the use of non-firm imports and exports.

4.2.5 Transmission Modelling

In the model, the NLIS is separated into two zones linked by transmission - the IIS region and the LIS region, with the LIL connecting the two. There are also two external regions modelled, representing the two connections to external markets via Quebec and Nova Scotia.[69] The transfer capability of each transmission line is included in the Reliability Model.

Each of the NLIS regions are further divided into sub-regions (e.g., Avalon, Off-Avalon, Lab-West, Lab-East) linked by the bulk transmission network. The inclusion of a simplified representation of the bulk transmission system in the Reliability Model ensures the system is capable of delivering electricity to meet customer requirements and that all known constraints are appropriately considered as part of the resource planning process.

Two preliminary transmission constraints were identified in operational studies for the IIS region and both were included in the Reliability Model.[70] From that analysis it was determined that in 2022 and beyond transmission constraints exist under the following scenarios: [71]

1. **Eastward power flows from Bay d'Espoir must be limited to a maximum of approximately 650 MW.**
2. **When the Holyrood GT is out of service or not operating, eastward power flows from Bay d'Espoir must be limited to a maximum of approximately 615 MW.**

In the LIS there are transmission constraints on the radial feeds to the Eastern and Western regions.[72] Analysis supporting reinforcement of the Labrador transmission system to address these transmission constraints has been presented to the Board as part of the Labrador

[69] Refer to Figure 3 Newfoundland and Labrador Model Topography in Section 4.2.
[70] Stage 4A LIL Bipole: Preliminary Assessment of High Power Operation, TransGrid Solutions, November, 2018
[71] Exact constraints to be confirmed as part of Trans Grid High Power Operational Studies.
[72] In the current transmission system a maximum of 350 MW can be delivered to Labrador West and a maximum of 77 MW can be delivered to Labrador East.

Interconnected System Expansion Study.[73] Consideration of these transmission constraints is beyond the scope of this analysis.

4.2.5.1 *Transmission Modelling: LIL Reliability*

With the introduction of Muskrat Falls, a large portion of the generation serving the Island load will be located in Labrador. Therefore, the reliability of the LIL is a key driver of NLIS reliability. Volume I, Attachment 7 provides a Technical Note which discusses the robust nature of the design and construction of the LIL, the anticipated asset reliability, and the anticipated required maintenance. While Hydro is confident in the design and construction of the LIL, it recognizes that the Board and parties wish to better understand the implications associated with a prolonged outage of the LIL.

The reliability of the LIL is an important contributor to NLIS reliability

As such, the reliability of the LIL has been modelled in two ways:

1. **Anticipated reliability of the LIL: This method models the LIL reliability probabilistically using a FOR of 0.56% per pole, and 0.01% for the bi-pole (full link).**
2. **Extended outage of the LIL: This method models a scenario where the LIL is unavailable for three weeks to quantify the resultant system reliability and identify the costs associated with providing incremental generation to reduce the loss of load probability to satisfy Hydro's proposed criteria.**

The LIL is modelled at maximum capacity of 900 MW (450 MW per pole) before losses. The Reliability Model includes a loss equation function that dynamically calculates losses incurred

[73] As filed with the Board on October 31, 2018.

by delivering energy from Muskrat Falls to the IIS. The LIL also has the ability for each pole to be loaded to 1.5 times its rated capacity on a continuous basis (675 MW).[74] In the case of an interruption to one pole lasting less than ten minutes, each pole is designed such that the pole that remains in service can continue to operate at 900 MW. For an interruption to one pole lasting more than ten minutes, the pole that remains in service is capable of operating at 675 MW.[75] In the case of a sustained outage to one or more poles of the LIL, the amount of capacity required to be delivered to Nova Scotia decreases by an amount proportional to the outage severity. In the instance of a full bipole outage there is no requirement to deliver the Nova Scotia Block. The Reliability Model incorporates these operational parameters.

4.2.6 Emergency Operating Procedures

Resources are dispatched by Newfoundland and Labrador System Operator ("NLSO") in accordance with "Operations Standard Instruction BA-P-012 (T-001) Operating Reserves," which outlines the requirements to assess and maintain sufficient operating reserve to meet current and anticipated customer needs under normal operating conditions and for specific contingency situations that result in reductions to resources.

In the event of a developing or sudden capacity shortage, the NLSO follows a number of possible mitigating actions determined based on the system conditions at the time. While some of the associated actions can provide some system relief (e.g., the implementation of voltage reduction), from a long-term planning perspective Hydro has conservatively not included the associated capacity benefits explicitly in its Reliability Model.

[74] Each pole can also be temporarily loaded to twice its rated capacity for ten minutes (900 MW), allowing for no interruption of supply for momentary pole trips.
[75] Operation in sustained monopole mode incurs higher transmission losses. This higher loss rate has been included in Hydro's Reliability model.

5 Modelling Results

5.1 Probabilistic Capacity Planning Results

The loss of load expectation and resultant planning reserve margin results are presented in Table 4, with the proposed criteria highlighted in blue. The results include the LOLE that has been used to determine the planning reserve margin (% and MW). The results are generally aligned with planning reserve margins observed across other utilities that have predominantly hydraulic production. The NERC "2017 Long-Term Reliability Assessment" notes a reference margin level of 12.0% for Manitoba Hydro and 12.9% for Hydro Québec, both utilities with a predominantly hydraulic generation asset base.[76]

To ensure that capacity and energy requirements are met on the LIS, that system's requirements are compared with the 300 MW block of Recapture power and associated energy and the 225 MW block of TwinCo power, all available from CF(L)Co. to ensure sufficient supply.

Table 4: Planning Reserve Margin Results

	Newfoundland and Labrador Interconnected System		Island Interconnected System	
		Proposed		**Proposed**
Loss of Load Expectation (LOLE)	0.2	**0.1**	0.2	**0.1**
Planning Reserve Margin (%)	11%	**13%**	13%	**14%**

5.2 Operational Reserve Requirements Results

As detailed in Section 3.3.1.2, Table 5 presents operational reserves required to be available in accordance with NPCC criteria.

[76] "2017 Long-Term Reliability Assessment," NERC, <https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf>

Table 5: Operational Reserve Requirements Results

	Operational Reserve Required
Ten Minute Reserves	197.5 MW
Thirty Minute Reserves	99 MW
Total	**296.5 MW**

As noted in Section 4.2.2.1, the assessment of the firm plant output of MFGS will continue to be analyzed as the plant becomes operational. If it is determined that the plant is proven capable of rated output (i.e., 824 MW) through the winter the operational reserve requirements will increase from 296.5 MW to 309 MW.

5.3 Reserve Margin Adopted

Both the probabilistic and deterministic criteria must be met. As such, Hydro recommends adoption of the probabilistic capacity criteria presented in Table 6. Additionally, Hydro recommends that the resultant reserve margin be sufficient to meet the operational reserve requirements previously presented in Table 5.

Table 6: Planning Reserve Margin Recommended Criteria

	Newfoundland and Labrador Interconnected System	Island Interconnected System
LOLE (days/year)	0.1	0.1
Planning Reserve Margin (%)	13%	14%

5.4 Comparison against Other Utilities

Figure 6 presents a comparison of the proposed planning reserve margin to those used by other Canadian regions and/or utilities. The proposed planning reserve margin is higher than those used by Manitoba Hydro, the BC region, and Sask Power, and on par with that used by Québec. While the proposed planning reserve margin is lower than that used in the Maritimes, the Maritimes have a varied supply mix with a larger penetration of thermal generation. Note that utilities with mainly hydro resources tend to use lower reserve margins, as the hydraulic assets generally experience lower forced outages than thermal assets.

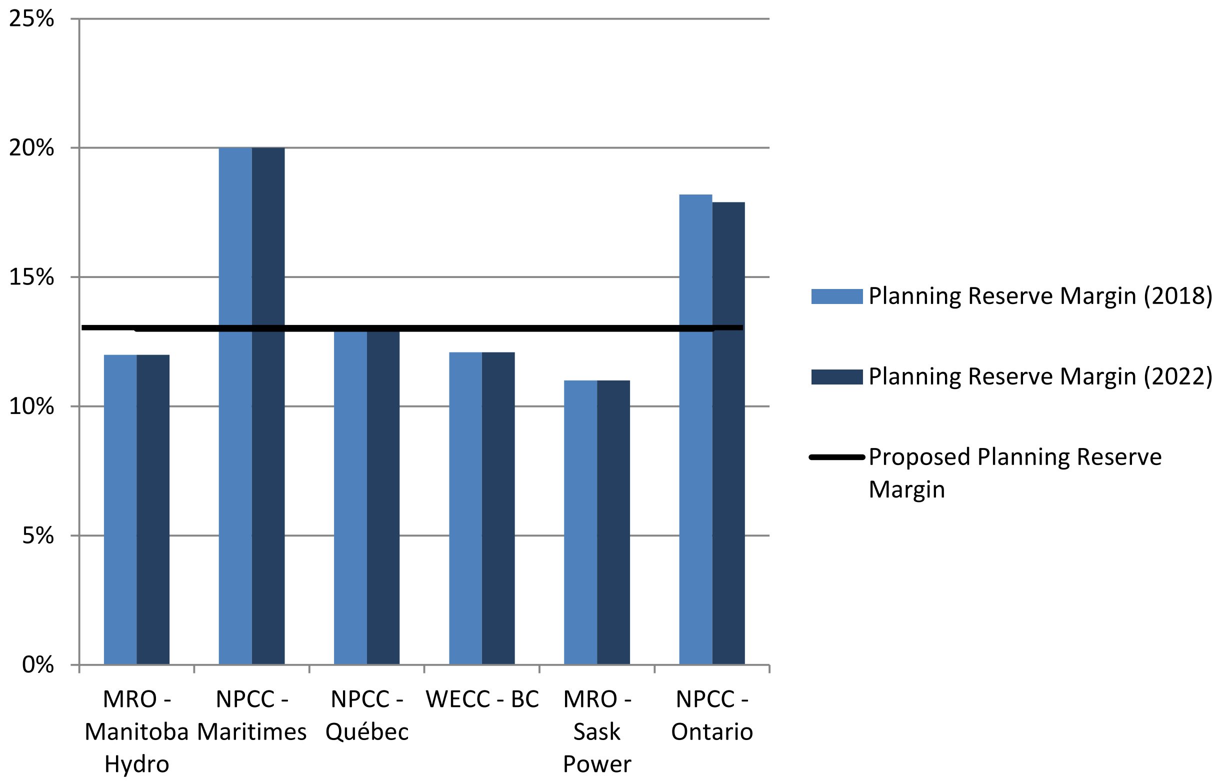


Figure 6: Proposed Planning Reserve Margin Compared to Other Canadian Jurisdictions

6 Conclusion

This report proposes changes to resource planning criteria stemming from the system changes as a result of interconnection with the North American grid and the integration of the Lower Churchill Project assets. Specifically, Hydro recommends:

- **Planning for the NLIS on a regional and sub-regional basis**
- **Continuing evaluation of supply adequacy both probabilistically and deterministically**
- **Adoption of a system reserve margin that provides a 0.1 LOLE**
- **Maintaining sufficient operating reserves to meet NPCC operational reserve requirements, and**
- **Extending existing IIS system energy criteria to the NLIS.**

Attachment 1

External Review and Validation

MEMORANDUM

To: Newfoundland Labrador Hydro

From: Daymark Energy Advisors

Date: November 2, 2018

Subject: Daymark Evaluation of Newfoundland Labrador Hydro Reliability Criteria

Disclaimer: This memorandum was prepared for the exclusive use of Newfoundland and Labrador Hydro and shall not be distributed to unaffiliated third parties without the express permission of Daymark Energy Advisors.

Daymark Energy Advisors ("Daymark") was retained by Newfoundland Labrador Hydro ("NLH") to conduct an evaluation of the reliability criterion and advise in the decision-making and analytical processes in determining the resource adequacy margins for the Newfoundland and Labrador Interconnected System as well as the Island Interconnected System.

This memorandum is a high-level overview of the assessments and advisory support provided by Daymark to NLH in the evaluation of its reliability criterion. For evaluating the reliability criteria, Daymark specifically analyzed the following topics and provided analytical as well as advisory support to NLH:

- Insights on resource adequacy criteria across industry
- Insights on load forecasting methodology implemented for reliability criteria calculations
- Determination of load forecast uncertainty concerning historical weather variability
- Insights on renewable resource assumptions for reliability criteria calculations
- Insights on import and export assumptions for reliability criteria calculations
- Overview of hydrology across two hydro-centric Canadian utilities
- Insights on O&M cost assumptions across industry
- Review of NLH's reliability margin methodology and calculations

The following sub-sections provide a brief summary of each of the afore-mentioned areas of support provided by Daymark to NLH. Each subsection includes a reference to the additional detailed report provided by Daymark in support of the assessments.

Insights on Resource Adequacy Criteria Across Industry

Daymark investigated the resource adequacy and reliability criteria for several regions[1] to document current trends in standards and modeling practices. In particular, the standards for load imbalance were identified for comparison purposes for each region, as well as the associated reserve margins. While many of the regions surveyed adhered to an accepted industry standard for exceeding generation capacity by load, this standard may be interpreted differently in each region. Through this effort, Daymark highlighted the importance of understanding the nuances of implementing the reliability criteria standards across several regions. A detailed review of Daymark's insights is provided in 'Appendix A - Resource Adequacy Criteria Survey'.

Insights on Load Forecasting Methodology Implemented for Reliability Criteria Calculations

Daymark investigated load forecasting methodologies implemented across North America for reliability criteria calculations. Regions included in the North American Electric Reliability Corporation ("NERC") jurisdiction have incorporated load forecast uncertainty for reliability assessment purposes mainly by accounting for weather and/or economic and demographic variables. Daymark identified that a majority of the regions in NERC have explicitly accounted for the variability associated with weather and economic variables via simulation methods. Few regions implicitly accounted for the uncertainties surrounding input variables used in the load forecast modeling and in the forecast trends by considering only the standard deviation of forecasted load. In addition, Daymark also identified several regions considering the variability observed on historical hourly peak load to directly account for load forecast uncertainties. A comparison of load forecasting methodology across NERC regions is provided in the Appendix section of the 'Load Forecast Uncertainty for Reliability Purpose' document.

Determination of Load Forecast Uncertainty Concerning Historical Weather Variability

To ensure NLH's Load Forecast incorporated uncertainty, as recommended by NERC, Daymark developed an estimate of the impact of representative historical weather variability on peak demand (MW) forecasts for the Island region, given weather's role as a critical driver of system peak and directly impacting reliability. The method explicitly accounted for such weather variability using Monte Carlo simulation. Specifically, probabilistic models were used to generate 10,000 possible future wind chill values, a measure of weather variable used in the load forecasting methodology, for each year of the load forecast from 2018

[1] Northwest Bonneville Power Authority (BPA), Maritimes, Quebec, Saskatchewan Power (SaskPower), ISO-New England (ISO-NE), Manitoba Hydro, Southwestern Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Western Electricity Coordinating Council – California/Mexico (WECC-CAMX), Hawaii Electric Co. (HECO), New Zealand, British Columbia (BC), Ontario, Ireland, and the United Kingdom (National Grid UK)

to 2037. These future possible wind-chill related values and the historic relationship between peak demand and the weather variable, estimated using industry standard regression models, were then used to quantify the additive peak demand component associated with weather variability. Daymark's analysis and determination is provided in the 'Load Forecast Uncertainty for Reliability Purpose' document.

Insights on Renewable Resource Assumptions for Reliability Criteria Calculations

Daymark surveyed several regions[2] in the NERC jurisdiction to identify and evaluate the assumptions for contributions from wind and solar resources in the resource adequacy and reliability criteria calculations. Daymark identified that eight of the ten surveyed regions utilized summer and winter contribution percentages for renewable resources. These percentages were applied to the resources' nameplate capacities. Due to the high degree of variability across different regions, Daymark highlighted the importance of assessing region-specific historical renewable resource data to determine the contribution assumptions for reliability criteria calculations. A complete summary and comparison of renewable resource contribution assumptions is available in Section B of 'Appendix A - Resource Adequacy Criteria Survey'.

Insights on Import and Export Assumptions for Reliability Criteria Calculations

Given the importance of import and export assumptions in NLH's reliability criteria calculations, Daymark investigated the assumptions for external transfers considered in several regions for reliability calculations. Daymark's survey highlighted the various alternatives considered across regions for firm/non-firm import and export contracts. Section C of 'Appendix A - Resource Adequacy Criteria Survey' provides more details on the insights identified by Daymark.

Overview of Hydrology Across Two Hydro-Centric Canadian Utilities

Daymark additionally performed research on the hydrology used to determine water flow conditions and dependable energy calculations for hydro-centric regions such as Manitoba Hydro and Hydro Quebec. The summary provided to NLH highlighted the specific modeling used by the two regions, based on publicly available information. A review of Manitoba Hydro's planning is available in the "Summary of Manitoba Hydro's SPLASH model for hydrology" memo. Additional information on the energy criteria for the two hydro-centric regions is available in Section D of Appendix A - Resource Adequacy Criteria Survey report.

[2] Maritimes, Quebec, Saskatchewan Power (SaskPower), ISO-New England (ISO-NE), Manitoba Hydro, Southwestern Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Western Electricity Coordinating Council – California/Mexico (WECC-CAMX), Ontario

Insights on O&M Cost Assumptions Across Industry

To facilitate NLH's understanding of the O&M cost assumptions for various expansion options, Daymark analyzed a number of publicly-available data sources[3] to review the fixed and variable cost assumptions for gas turbines (combined cycle and combustion turbines), hydro units, wind units and solar units.

Daymark did not perform any engineering assessment on the O&M cost assumptions. Rather, efforts focused on analytical research to comparing the industry-wide standard costs for variable and fixed O&M costs to NLH's assumptions. NLH provided initial fixed O&M cost assumptions that were based on one operator per shift and two shifts per day. Based on discussions using Daymark's research, this assumption was revised to consider two operators per shift and two shifts per day. Daymark identified that the revised fixed and variable cost assumptions considered by NLH for gas turbines were in line with the accepted bandwidth assumed across the industry. With respect to hydro units, research showed that O&M cost assumptions are site-specific and directly dependent on each specific generating unit's technology and its location. Research also indicated that the O&M cost assumptions considered by NLH for its wind and solar expansion options were also within the acceptable cost bandwidths observed across the industry. The reviews of O&M cost assumptions considered across industry can be obtained from Daymark's "O&M Costs Comparison - Gas Turbine Alternatives" report and "O&M Costs Comparison - Hydro, Wind, Solar Alternatives" report.

Review of NLH's Probabilistic Planning Reliability Criteria Calculation

Daymark performed a high-level review of the methodology implemented by NLH in determining the probabilistic planning reliability criteria for the Island Interconnected System (sub-region) as well as the Newfoundland and Labrador Interconnected System (region).

Daymark's review concluded that the methodology applied by NLH in determining the probabilistic planning criteria was consistent with the industry-standard approaches. Additional information on Daymark's review can be obtained from "Probabilistic Planning Reliability Criteria Calculation – Daymark High-Level Review" memorandum.

[3] References for the cost assumptions are available in the 'O&M Cost Comparison' reports

DAYMARK ENERGY ADVISORS

MEMORANDUM

To: Newfoundland and Labrador Hydro

From: Daymark Energy Advisors

Date: November 6, 2018

Subject: Probabilistic Planning Reliability Criteria Calculation – Daymark High-Level Review

Disclaimer: This memorandum was prepared for the exclusive use of Newfoundland and Labrador Hydro and shall not be distributed to unaffiliated third parties without the express permission of Daymark Energy Advisors.

Daymark Energy Advisors ("Daymark") performed a high-level review of the methodology implemented by Newfoundland and Labrador Hydro ("NLH") in determining the probabilistic planning reliability criteria for the Island Interconnected System (sub-region) as well as the Newfoundland and Labrador Interconnected System (region).

Using Daymark's research findings and recommendations on reliability criteria across several regions[1] , NLH determined the following probabilistic planning reliability criteria for the NLH system:

- Both the region and the sub-region should each have sufficient generating capacity to satisfy a LOLE target of not more than 0.1
  - where LOLE or Loss of Load Expectation is the expected number of days each year where available generation capacity is insufficient to serve the daily peak demand.

NLH's Approach:

NLH utilized a three-step approach in identifying the planning reserve margin required to meet the 0.1 LOLE target for the region and the sub-region.

[1] Northwest Bonneville Power Authority (BPA), Maritimes, Quebec, Saskatchewan Power (SaskPower), ISO-New England (ISO-NE), Manitoba Hydro, Southwestern Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Western Electricity Coordinating Council – California/Mexico (WECC-CAMX), Hawaii Electric Co. (HECO), New Zealand, British Columbia (BC), Ontario, Ireland, and the United Kingdom (National Grid UK)

Step 1: For a selected model year (2026), a detailed hourly system model was developed in Plexos[2] modeling tool.

Step 2: The load shape was escalated through a linear multiplier.

For each escalation, a Monte Carlo simulation consisting of 4800 trials was performed. The LOLE for each escalation was not directly obtained from the Monte Carlo simulation. The simulation instead, provided the Loss of Load Probability ("LOLP") for each hour – the probability that demand for each hour was not served by the available generation capacity, across 4800 trials.

Step 3: From the LOLP calculated for each hour using the Monte Carlo simulation under each escalation, the LOLE was determined for the region and the sub-region. Under an LOLE of 0.1, as defined in NLH's probabilistic planning criteria, the planning reserve margin was calculated.

Daymark's Review:

Daymark reviewed the three steps and the associated workpapers performed by NLH and analyzed the results from this analysis.

From Step 1, the selection of 2026 as model year considered expected retirements and new resource additions, including the Muskrat Falls Project. The hourly system model developed in Plexos included probability distributions for some key variables including load weather variability, generation unavailability and the Labrador Island Link forced outage rate. These assumptions considered Daymark's research findings, as shown in 'Appendix A - Resource Adequacy Criteria Survey', as well as Daymark's determination of load forecast uncertainty taking historical weather variability into consideration, as highlighted in the 'Load Forecast Uncertainty for Reliability Purpose' document.

Under Step 2 and Step 3, the escalation technique used by NLH was consistent with NERC recommendations[3].

[2] Plexos is a power system simulation tool, developed by Energy Exemplar.

[3] NERC 2016 Probabilistic Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016ProbA_Report_Final_March.pdf

For LOLE determination, NLH adapted a hybrid-Monte Carlo simulation process. This approach was consistent with the analytical approach methodology identified by NERC[4]. The LOLE under this methodology for the region and sub-region is calculated as:

$$LOLE = \sum_{d=1}^{365} (LOLP)^{Peak,d}$$

where: d is a variable representing a day, $(LOLP)^{Peak,d}$ refers to the LOLP of the hour with the peak demand for day d.

Daymark confirmed the consistency in application of such a hybrid Monte-Carlo approach across other regions for reliability metric calculations.[5]

NLH identified the planning reserve margin targets as shown in Table 1:

Table 1: Planning Reserve Margins Calculated by NLH through Probabilistic Criteria

	Newfoundland and Labrador Interconnected System	Island Interconnected System
Planning Reserve Margin (%)	13	14

The workpapers provided by NLH demonstrated consistency in calculation of these values.

Daymark's review concluded that the methodology applied by NLH in determining the probabilistic planning criteria was consistent with the industry-standard approaches.

[4] NERC Probabilistic Adequacy and Measures Report: https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf

[5] IEEE LOLE Working Group: http://egpreston.com/Presentation3.pdf and NREL Comparing Resource Adequacy Metrics: https://www.nrel.gov/docs/fy14osti/62847.pdf

Summary

Dr. Wenxiong Huang, the principal consultant with WH Energy Solutions LLC, is engaged by Newfoundland and Labrador Hydro to review the PLEXOS models to evaluate the reliability of system and the model in support of its reliability and resource adequacy review. Over the past several months (May 2018 to November 2018), Dr. Huang performed a comprehensive review of the Plexos reliability model and expansion model. After many iterations including model updates and PLEXOS software revisions, it is confirmed that the reliability model and the expansion model adequately represent the system supply and demand conditions and can be used to produce probabilistic reliability measures like Expected Unserved Energy (EUE), Loss of Load Hours (LOLH), and Loss of Load Expectation (LOLE). The reserve margin developed is also used to guide the development of the least cost resource expansion plan in the expansion plan model.

The Reliability Model

A reliability model of NLH system is developed in PLEXOS with major demand and supply nodes and transmission lines (see Appendix for a topology schema).

Three load objects are modelled in Labrador region: Lab East, Lab West, and Lab West Industrial, each having its own load shape. Two load nodes are modeled in the Island region using the one Island region load shape.

All generation resources (hydro, wind, thermal) are modeled in their respective nodes. Key inputs for the resources include 1) max/min capacity, 2) firm capacity, 3) maintenance rate/duration, 4) forced outage rate and duration, 5) seasonal energy availability, 5) hourly profiles

Major transmission lines are modelled with max flow limit, firm capacity and linear/quadratic loss. Outage rates and durations are modelled for the Labrador Island Link, with separate outage rates for the Bipole and Monopole outages.

Contractual load obligation from Muskrat Falls to Nova Scotia Power is modeled through a Physical contract object. The load obligation is also a function of the availability of the Labrador Island Link (LIL).

Due to the nature of the system (hydro system with seasonal energy availability and long transmission lines), chronological Monte Carlo simulation is used to evaluate the reliability of the system. Key features of the stochastic model include:

1) Stochastic load (Lab East, Lab West, Island)
2) Resource maintenance and forced outage
3) Stochastic hydro energy availability with seasonal variability
4) Stochastic wind generation with seasonal probability distribution function
5) Transmission line loss
6) Random outages on the Labrador Island Link Monopole and Bipole
7) Emera contract obligations that depend on transmission line availability
8) Twinco Block generation is constrained to serve Labrador load
9) Transgrid constraints that limit the transmission flow to the Avalon in the event of LIL outage or "Holyrood GT" outage.

Model Review

Dr. Huang worked with NLH staff to review the input parameters and make sure the PLEXOS model accurately represented the intended input assumptions.

We also reviewed and confirmed other key stochastic model parameters including:

1) Model initial random number seed to ensure simulation could be replicated
2) Number of random samples and outage samples to ensure proper convergence

For each simulation, the following PLEXOS simulation phase is used:

1) PASA is used to schedule maintenance
2) MT is used to allocate annual/monthly energy limit and constraints
3) ST is used to dispatch resources to meet load over transmission line and track all loss of load events for all hours of the study year.

For each stochastic simulation, PLEXOS can calculate reliability measures like Expected Unserved Energy (EUE), expected Loss of Load Hours (LOLH). The Loss of Load Expectation (LOLE) is calculated using a custom tool based on the hourly output. LOLE is calculated using the daily peak hour loss of load probability.

Model Validation

Dr. Huang did extensive PLEXOS model runs with 4800 annual hourly simulations for each case. Detailed stochastic output by sample is also generated to test the distribution of the random variables representing load, hydro energy, and wind generation distribution.

From the simulation output, it is verified that

1) Outage/samples are generated properly,
2) Generator maintenance, generator and line outages match input distribution specifications
3) Wind generation and seasonal hydro energy also match input probabilistic distribution
4) All constraints (Twinco block generation, transmission constraints, Emera load obligation, etc.) are enforced properly

Sensitivity Analysis

The reliability model contains several sensitivity cases to evaluate the impact of a prolonged LIL outage and addition of 66 MW generic CT. These sensitivity cases were performed, and the results make sense.

RM Calibration

To calibrate the level of reserve margin that corresponds to 0.1 LOLE reliability, iterative stochastic simulations were performed by scaling Island/providence load until desired 0.1 LOLE is reached. This desired reserve margin is then used in the expansion model to guide the development of least cost resource plan to satisfy the 0.1 LOLE reliability requirement.

Sample Output

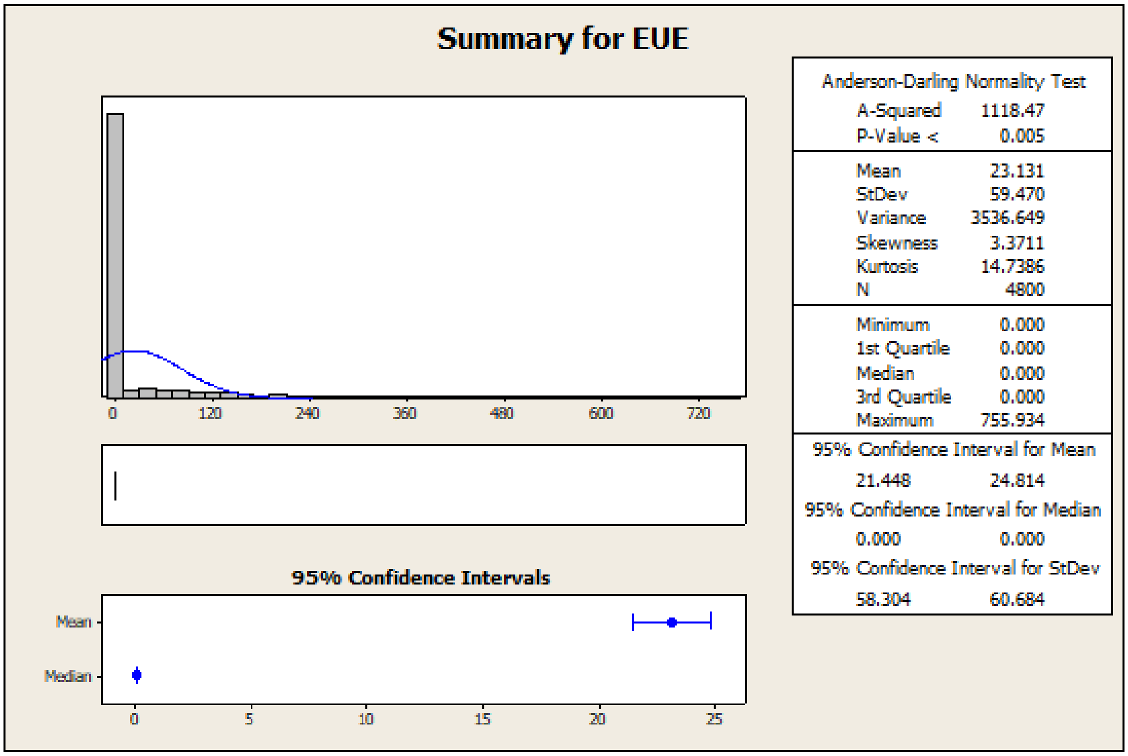
The following tables show the expected results from a 4800 sample simulation

Full Model - 2026, Base 1				
Island			Province	
LOLE	**0.02458**		**LOLE**	**0.02292**
LOLH	**0.23313**		**LOLH**	**0.23313**
EUE	**23.13081**		**EUE**	**23.13081**
Peak	1655.8		Peak	2033.4
Loss @ Peak	46.4		Loss @ Peak	156.0
Peak with Losses	1702.21		Peak with Losses	2189.41
Peak Losses	60.5		Peak Losses	161.1
Firm Capacity	2079.0		Firm Capacity	2599.0

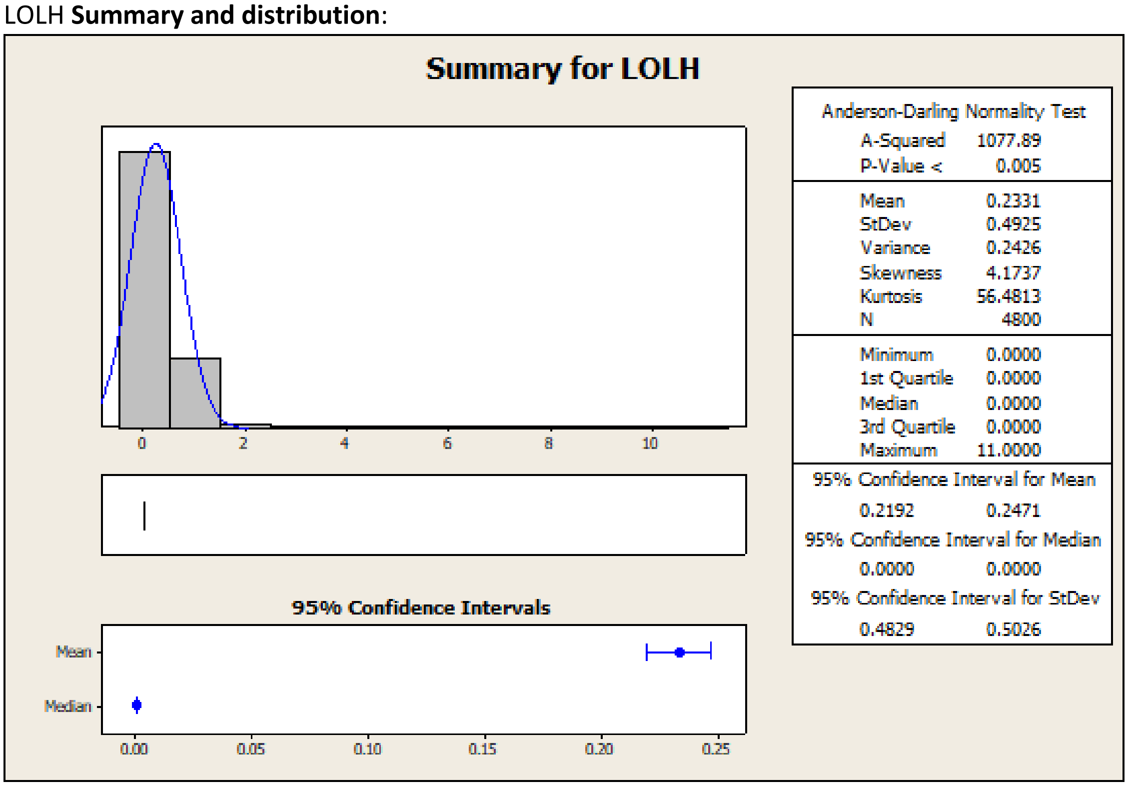
Besides the expected values, we can also calculate the confidence interval of the reliability measure. For example, as shown below, the confidence interval for LOLH is between 0.22 and 0.25.

EUE (GWh)		*LOLH*	
Mean	23.13	Mean	0.23
Standard Error	0.86	Standard	0.01
Median	-	Median	-
Mode	-	Mode	-
Standard Deviation	59.47	Standard	0.49
Sample Variance	3,536.65	Sample V	0.24
Kurtosis	14.74	Kurtosis	56.48
Skewness	3.37	Skewnes	4.17
Range	755.93	Range	11.00
Minimum	-	Minimum	-
Maximum	755.93	Maximun	11.00
Sum	111,027.88	Sum	1,119.00
Count	4,800.00	Count	4,800.00
Confidence Level(95.0%)	1.68	Confiden	0.01
LB	21.45		0.22
UB	24.81		0.25

EUE **Summary and distribution**



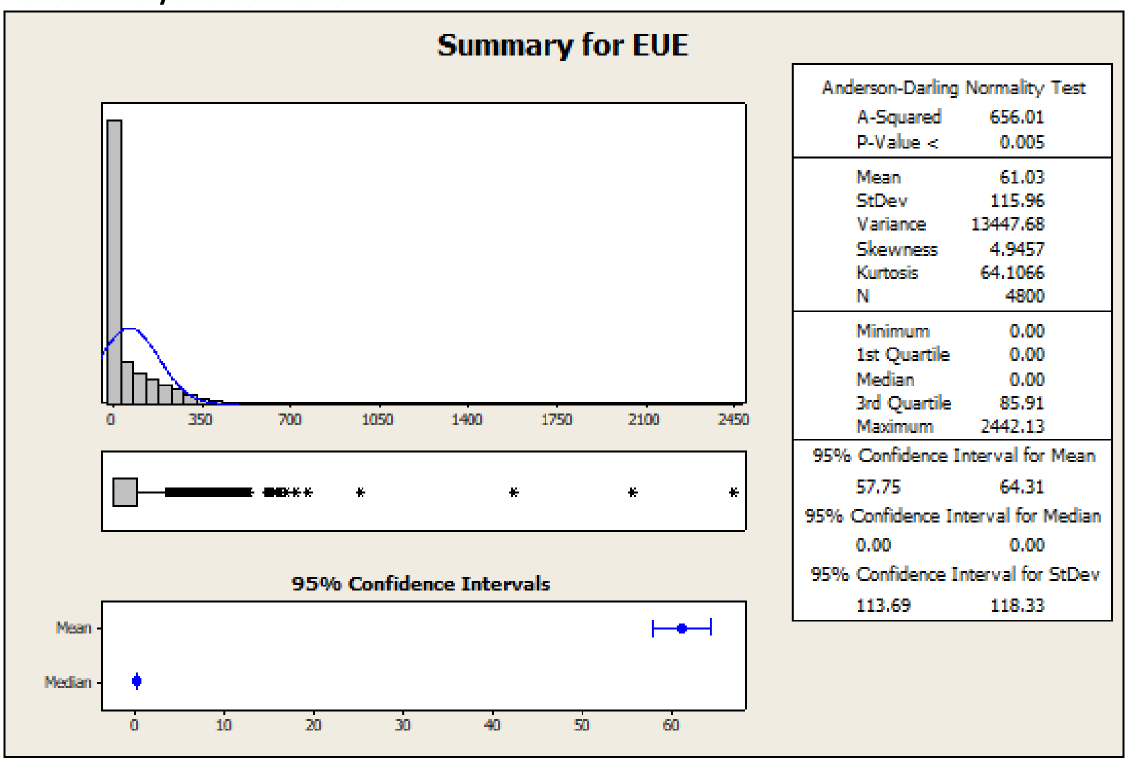
LOLH **Summary and distribution**:



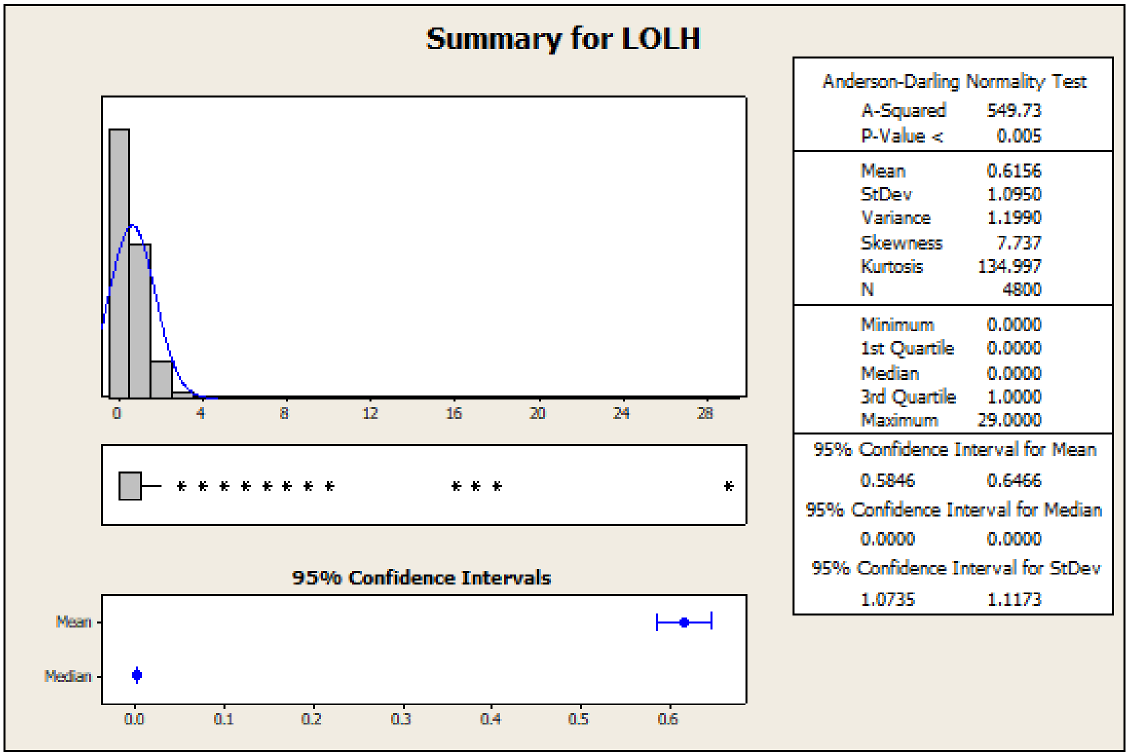
When the Island load is scaled up by a factor of 1.075, the LOLE is about 0.1.

Full Model - 2026, Base 2	Island 1.075			
Island			Province	
LOLE	**0.10083**		**LOLE**	**0.09854**
LOLH	**0.61562**		**LOLH**	**0.61562**
EUE	**61.03315**		**EUE**	**61.03315**
Peak	1780.0		Peak	2156.6
Loss @ Peak	50.9		Loss @ Peak	159.7
Peak with Losses	1830.91		Peak with Losses	2316.36
Peak Losses	60.1		Peak Losses	165.3
Firm Capacity	2079.0		Firm Capacity	2599.0

EUE Summary and distribution:



LOLH Summary and distribution:



The Expansion Model

The expansion model is the deterministic model with similar topology, load, resource, and transmission. The focus of the expansion model is to develop a long-term expansion plan to minimize the net present value (NPV) of the capital and operation cost, taking consideration of market opportunities, as well as the contract obligation to Nova Scotia, subject to reliability requirements and operating reserve requirements.

Detailed cost information like heat rate, fuel cost, variable operation and maintenance cost are implemented to the resources.

Resource candidates included conventional hydro, CCGT, and CT. Renewable resources like wind and solar resources are also made available.

2-hour battery energy system is implemented as resource candidate and could be made available using a scenario.

The expansion plan model is set up to develop a least cost plan over 10 years with infinite end-effect. The MIP convergence criteria is set to very small 0.01% to ensure least cost solution.

The model also includes several load scenarios to access the robustness of the resource plan.

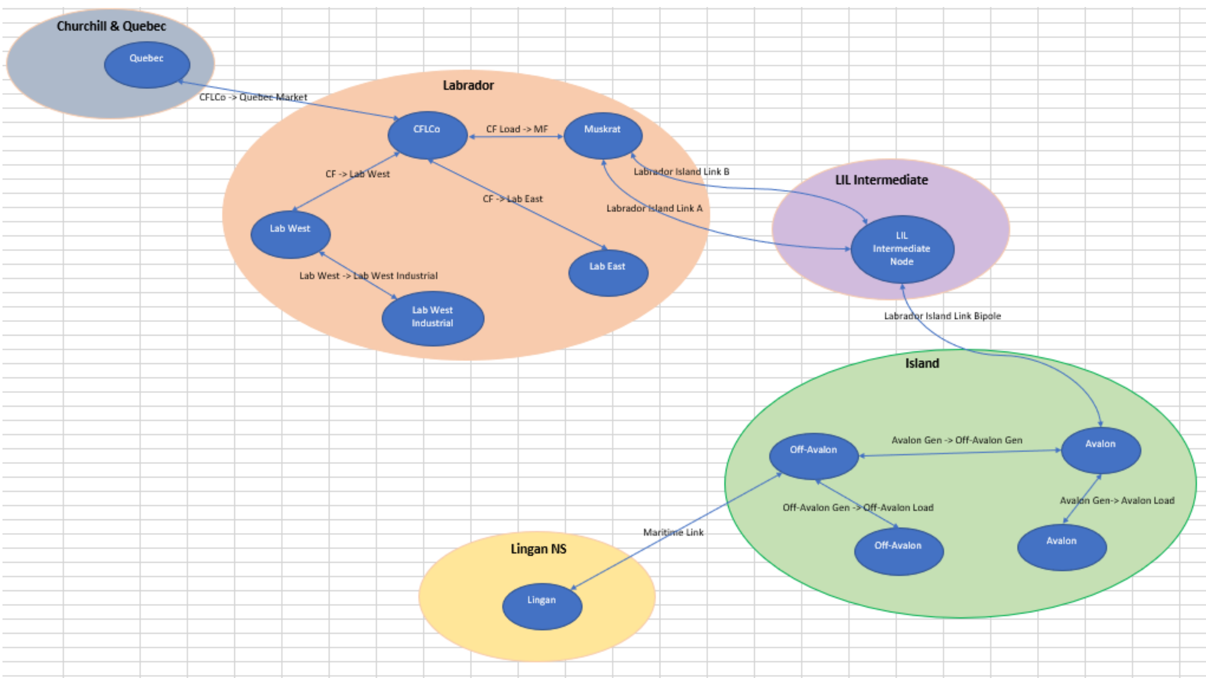
A complete simulation includes LT Plan phase where a least cost plan is determined, then followed by PASA phase to allocate maintenance, MT phase to solve seasonal constraints, then by ST phase to do more detailed dispatch to evaluate the system cost.

I have reviewed the model parameters and run the designed cases and verify that the model behaves as expected.

Conclusion

The reliability model is properly developed to assess the reliability of the system. The expansion model is also set up properly to enable the development of least cost expansion plan.

Appendix: Reliability Model Topology



Attachment 2

Resource Adequacy Criteria

RELIABILITY CRITERIA SURVEY

JULY 31, 2018

PREPARED BY

Daymark Energy Advisors

JULY 31, 2018

TABLE OF CONTENTS

DAYMARK ENERGY ADVISORS

JULY 31, 2018

I. RESOURCE ADEQUACY REVIEW

Daymark investigated the resource adequacy and reliability criteria for several regions in order to understand current trends in standards and modeling practices. In particular, the standards for load imbalance were researched for each region, as well as the associated reserve margins. Furthermore, the contributions of wind and solar resources within the context of resource adequacy and reliability modeling were also explored. While many of the regions surveyed adhered to a 1-in-10 standard for the exceeding of generation capacity by load, this standard may be interpreted differently in each region. It is important to understand the nuances of the 1-in-10 standard since it can make it difficult to directly compare the loss-of-load criteria across regions.

A. Regional Analysis

The regions examined in this analysis were drawn mainly from North America, although a few regions were also selected from other areas of the world. Regions with generally similar geographic and power system characteristics to those of Newfoundland & Labrador Hydro were selected for this analysis. More specifically, areas that represented island systems or accessed notable hydro resources were chosen. The following regions or assessment areas were chosen for this survey: Northwest Bonneville Power Authority (BPA), Maritimes, Quebec, Saskatchewan Power (SaskPower), ISO-New England (ISO-NE), Manitoba Hydro, Southwestern Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Western Electricity Coordinating Council – California/Mexico (WECC-CAMX), Hawaii Electric Co. (HECO), New Zealand, British Columbia (BC), Ontario, Ireland, and the United Kingdom (National Grid UK).

Based on our review of the resource adequacy and reliability criteria for the abovementioned regions, most regions use modeling programs that utilize Monte Carlo simulations for reliability planning. Among these Monte Carlo simulation programs, the General Electric's Multi-Area Reliability Simulation Software Program (GE MARS) was the most commonly used. ERCOT also uses a Monte Carlo-based program known as SERVM. Some of the other programs used by the regions surveyed include PLEXOS (Monte Carlo-based), GENYSIS, and MAVRIC. It should be noted here that the availability of these models varies considerably. Models like GE-MARS have been available for 30 years or more in contrast to models such as PLEXOS which have been available only over the last decade. The longevity of programs like GE-MARS is due to its popularity among utilities and Regional Transmission Organizations (RTOs), who have stayed with these models because of their familiarity and the timely updates to the software.

Each region adheres to a specific standard regarding the likelihood of loss-of-load events. These standards are based on various probabilistic metrics. Among the regions surveyed, the two types of probabilistic metrics most commonly used were Loss-of-Load Probability ("LOLP") and Loss-of-Load Expectation ("LOLE"):

- LOLP is the probability of hourly demand or system daily peak surpassing the accessible generation capacity for a particular time period.
- LOLE typically represents the expected number of days each year where available generation capacity is inadequate to meet the daily peak demand. This calculation of LOLE is known as classic LOLE. However, LOLE may also be calculated as the projected number of days each year when available generation cannot meet the daily load demand in any hour at least once within that day.
- Hourly LOLE, which is often known as Loss-of-Load Hours ("LOLH"), is the expected number of hours each year where the hourly demand of a system is predicted to surpass generating capacity. The calculation of this metric relies on the hourly load in a particular time period. This differs from the calculation of classic LOLE where the daily peak is used. Therefore. a LOLH of 2.4 hours per year is not the same as the classic LOLE of 0.1 days per year.[1]

Among the regions surveyed, most regions utilized a loss of load expectation (LOLE) of 0.1/years (or 0.1 days per year), which is a loss of load probability of one day in ten years. Both Ireland and National Grid UK had hourly LOLEs (or LOLHs) that were less stringent at 8 hours per year and 3 hours per year, respectively. HECO also has a much less strict LOLP of one day in 4.5 years.

The criteria selected in each region is ultimately translated into a required level of reserve capacity to ensure compliance. Reference reserve margins are the percentage of installed reserve capacity in excess of load. This metric defines the amount of additional capacity required to meet unexpected demand increases or capacity shortages. Across several of the regions, the reference reserve margins range from 12% to 16.9%, with the average margin percentage equaling approximately 14.2%. (See Appendix A for more information on reliability criteria by region).

[1] NERC Probabilistic Assessment Technical Guideline Document (August 2016), p. 2.

B. Renewable Contribution

Many of the regions surveyed have specifically accounted for the contribution of wind and solar resources to resource adequacy and reliability. Most of the regions utilize a summer and winter contribution percentage for these resources. This percentage is typically applied to the nameplate capacity of the resource.

Wind resource percentage contributions vary widely. In the summer, this contribution percentage ranges from 5% to 36% across regions, with the average percentage equaling close to 20%. In winter, the wind resource contribution percentage ranges from 0% to 30%, with the average percentage reaching approximately 16%.

Regarding solar resources in summer, the percentages across regions vary between 10% to 77%, with an average of 37%. Lastly, the winter contribution percentages of solar resources range from 0% to 10%, with the average percentage equaling 5%. (See Appendix B for more information on Wind and Solar contributions.)

The high degree of variability makes it difficult to compare results across regions. The best guide is likely the specific historical availability experienced in a given region.

C. Imports and Exports

Firm capacity transfers are reflected in the reliability criteria for several of the aforementioned regions. SPP and WECC explicitly model these transfers, while Saskatchewan (SaskPower) models imports as load modifiers with hourly load modification for a typical week. Quebec also considers the transfer capabilities between the region and New Brunswick, Ontario, New England, and New York while excluding the import capabilities of the HVDC Sandy Pond-Nicolet interconnection. The Flow limits (MW) out of Quebec are 1,029 for New Brunswick, 2,545 for Ontario, 2,275 for New England, and 2,125 for New York. The Flow limits (MW) into Quebec are 785 for New Brunswick, 1,945 for Ontario, 170 for New England, and 1,100 for New York. Manitoba (Manitoba Hydro) accounts for capacity and energy import contracts during the winter season in exchange for energy exports during the summer season. These agreements allow for an exchange of capacity of 550 MW in 2015/16, 625 MW in 2016/17, 550 MW from 2020/21 until 2024/25, and 200 MW until expiration in 2029/30. BPA also includes imports and intra-regional transfers in their reliability criteria.

D. Energy Criterion

The energy criterion of hydro-centric regions, namely Hydro-Quebec and Manitoba Hydro, revolves around the supplying of sufficient energy during low flow or drought conditions. Manitoba Hydro's energy criterion necessitates that the system is able to provide adequate dependable energy resources to satisfy firm energy demand during a repeat of the lowest historic hydraulic system inflow conditions.[2] The base level of forecasted Manitoba load and existing export contracts shape firm energy demand. The accessible record of river flows, from 1912 to 2010, inform the historic hydraulic system inflows. The record of river flows has been modified to reflect current use conditions and to include systemic changes tied to anticipated future water usage and withdrawals upstream of the Manitoba region. Dependable energy resources include Hydroelectric generation facilities, thermal generation facilities, wind generation, projected demand side management unaccounted for in the load forecast, and imports from neighboring utilities. Regarding imports, these resources are considered dependable energy resources if they use Firm Transmission Service and are derived from a bilateral contract or an Organized Power Market. Furthermore, dependable energy imports are restricted to those imports that can occur during the Off-peak period and do not surpass the effective quantity of export contracts plus 10% of the Manitoba load.

Hydro-Quebec utilizes an energy criterion that dictates that adequate resources are made available to undergo a series of two consecutive years of low water inflows equaling 64 TWh or a series of four years equaling 98 TWh, and having a two percent occurrence probability.[3] To achieve this benchmark, operating measures and hydro resources are utilized appropriately.

[2] Appendix 4.1-Manitoba Hydro Generation Planning Criteria, p. 3. http://www.pub.gov.mb.ca/nfat/pdf/hydro_application/appendix_04_1_generation_planning_criteria.pdf

[3] NPCC 2017 Quebec Balancing Authority Area Comprehensive Review of Resource Adequacy (December 5, 2017), p. 18. https://www.npcc.org/Library/Resource%20Adequacy/2017%20Quebec%20Comprehensive%20Review.pdf

II. APPENDIX A: RELIABILITY CRITERIA SURVEY TABLE

Regions	Standards	Model Type	Notes
Northwest BPA	LOLP between 0 and 5% Conditional Value at risk (CVaR)	GENESYS	The CVaR metric gauges the magnitude of Energy-Not-Served (ENS) events under adverse load obligation and resource conditions for the Federal system. The metric analyzes the 5% of games that show the highest ENS amounts.
Maritimes	0.1/ years (1 day in 10 years) LOLE 20% Required Reserve	GE MARS (Type: Monte Carlo)	Maritimes have a required reserve of 20% of peak firm load. The Maritimes adhere to the NPCC resource adequacy criterion that requires a LOLE value of 0.1 days/years for all years in the 2017 Interim Review. The 2017 Interim Review assumed 300 MW of interconnection tie benefits form New England. Additionally, interconnection support from neighboring NPCC Areas was limited to 300 MW of tie benefits for all years.
Quebec	0.1/ years (1 day in 10 years) LOLE 12.6-13.4% reference reserve margin	GE MARS (Type: Monte Carlo)	Quebec utilizes the 0.1 days/year criteria specified by the NPCC in its Directory #1. There reference reserve margin is 12.6 % for winter 2017-2018, reaching 13.4% for winter 2021-2022. Quebec also has an energy criterion where ample resources are accessible during a sequence of 2 consecutive years of low water inflows equaling 64 TWh or a period of 4 consecutive years equaling 98 TWh, with a 2% probability of occurrence. The interconnection capabilities between Quebec and New Brunswick, Ontario, New England, and New York are included except for the import capabilities of the HVDC Sandy Pond-Nicolet interconnection. Flow Limits (MW) out of Quebec are 1,029 for New Brunswick, 2,545 for Ontario, 2,275 for New England, and 2,125 for New York. Flow limits (MW) into Quebec are 785 for New Brunswick, 1,945 for Ontario, 170 for New England, and 1,100 for New York).
Saskatchewan	LOLH/EUE 11% reference reserve margin	MARS (Type: Monte Carlo)	Saskatchewan has no anticipated firm exports for the assessment period. Imports are modeled as load modifiers with hourly load modification for a typical week.
ISO-NE	0.1/ years (1 day in 10 years) LOLE 16.6%-16.9% reference margin level	GE MARS (Type: Monte Carlo)	
Manitoba	0.1/ years (1 day in 10 years) LOLE 12% reference reserve margin	GE MARS (Type: Monte Carlo)	Seasonal diversity contracts exist between Manitoba Hydro and Northern States Power (NSP) and Great River Energy (GRE). There contracts are for capacity and energy imports during the winter season in exchange for energy and capacity exports during the summer season. These agreements allow for an exchange of capacity of 550 MW in 2015/16, 625 MW in 2016/17, 550 MW from 2020/21 until 2024/25, and 200 MW until expiration in 2029/30.
SPP	0.1/ years (1 day in 10 years) LOLE	GridView (Type: Monte Carlo)	DC tie and external capacity transactions are modeled as hourly generators at interconnection points to SPP.

	12% planning reserve margin		
ERCOT	0.1/ years (1 day in 10 years) LOLE 13.75% reference reserve margin	SERVM (Type: Monte Carlo)	
WECC-CAMX	14.76-16.14% reference reserve margin	MAVRIC (Type: Convolution)	The expected transfer capability between demand areas was modeled. For any hour where a demand area witnessed excess energy and the availability and demand distributions did not overlap, the excess energy was then made available to other neighboring areas.
Hawaii (Hawaii Electricity Co)	4.5 to 6 years/day LOLP		
New Zealand	Winter Energy Margin: 14-16% for New Zealand 25.5-30% for South Island 630-780 MW Winter Capacity Margin for North Island		The current margins are determined by the Electric Authority. The Electric Authority defined these margins based on a probabilistic analysis conducted in 2012. The security of supply standards is based on winter requirements. NZ's power system demand is highest during the winter period. The impacts of low thermal plant availability and low hydro inflows is also greatest during the winter period.
British Columbia	0.1/ years (1 day in 10 years)	The Monte Carlo simulation model for Planning Reserve Margin was developed in-house using Microsoft Excel and its programming language Visual Basic for Applications (VBA).	The company modeled various resource scenarios before establishing the preferred solution
Ontario	0.1/ years (1 day in 10 years) LOLE	GE MARS	The Ontario-Quebec Electricity Trade Agreement is modeled where Ontario makes 500 MW of capacity available to Quebec from December to March until 2023. The study does not rely on non-firm imports in the determination of the reserve margin requirements for Ontario.
Ireland	8 hours per year LOLE (hourly LOLE or LOLH)	Plexos	Forecasted capacity requirement satisfies the LOLE adequacy standard for the unconstrained all-island system. Ireland has a standard of 8 hours LOLE per year. Northern Ireland has a standard of 4.9 hours LOLE per year. hours. For all-island calculations, the security standard is 8 hours LOLE per year.
United Kingdom	3 hours per year LOLE (hourly LOLE or LOLH)	Dynamic Dispatch Model (DDM)	Model is similar to PLEXOS

III. APPENDIX B: WIND AND SOLAR CONTRIBUTION CRITERIA

Regions	Treatment of Solar and Wind Resources
Maritimes	Wind: Uses a year-round calculated equivalent capacity of 20 percent for New Brunswick, 12 percent for Nova Scotia, and 15 percent for Prince Edward Island of nameplate.
Quebec	Wind: Winter capacity contributions are 30 percent of contractual capacity. However, there is an exception of 104 MW derated to zero. Derated completely for summer.
Saskatchewan	Wind: Summer utilizes 10 percent of nameplate capacity, while winter uses 20 percent.
ISO-NE	Wind: Seasonal Claimed Capability is used. The contribution is based on the median of the wind resource's summer net output during reliability hours from the preceding year. These hours are 14:00-18:00, June through September. In summer, the values average to around 13.2 percent of nameplate. Solar: Seasonal Claimed Capability is used. The contribution is based on the median of the wind resource's summer net output during reliability hours from the preceding year. These hours are 14:00-18:00, June through September.
Manitoba	Wind: Uses a 35% and 0% capacity value for the summer and winter, respectively.
SPP	Wind: A 5% wind contribution is used for first three years if the LSE does not carry out the net capability calculation during the first 3 years of operation. After this period, the Net Capability Calculations is used by choosing the monthly MW values for the LSE's peak load month for each season. Solar: Same methodology as Wind (see above) but a 10% contribution is used instead.
ERCOT	Wind: Uses average historical availability during the highest 20 seasonal peak load hours for each season from 2009 to 2016. After each season, values are recalculated with new historical data. Currently, the wind contribution is 58% for coastal and 14% for non-coastal in summer, whereas the contribution is 35% for coastal and 20% for non-coastal in winter. Solar: Same methodology as Wind (see above) but 77% and 5% contributions are used instead (not region specific) for summer and winter, respectively.
WECC-CAMX	Wind: Historic on-peak performance for the expected peak hour for each year is used to calculated wind contribution. The actual capacity factor for the peak hour of the year is applied. Solar: Same methodology as Wind (see above) but the contribution is counted as 24% and 0% in summer and winter, respectively, for the interconnection.
Ontario	Wind: Contribution is forecast by using the Monthly Wind Capacity Contribution values. This forecast is based on the preceding 10 years of actual historic median wind performance during top 5 contiguous demand hours of the day for each shoulder period month or summer and winter season. Solar: The contribution is forecasted using the Monthly Solar Capacity Contribution values.

IV.REFERENCES

1. "2015 Pacific Northwest Loads and Resources Study" (BPA)
2. "2017 Long-Term Reliability Assessment" (NERC)
3. "2016 Probabilistic Assessment" (NERC)"
4. "NPCC 2017 Maritimes Area Interim Review of Resource Adequacy"
5. "NPCC 2017 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy"
6. "NPCC 2016 New England Interim Review of Resource Adequacy"
7. "Manitoba Hydro – 2016/17 Resource Planning Assumptions & Analysis"
8. "2017 Loss of Load Expectation Scope" (SPP)
9. "Hawaii Renewable Portfolio Standards Study" (2015)
10. "Security of Supply Annual Assessment 2018" (New Zealand)
11. "2016 Long Term Electric Resource Plan" (British Columbia)
12. "Ontario Reserve Margin Requirements 2018-2022"
13. "All-Island Generation Capacity Statement 2016-2025" (Ireland)
14. "2017 National Grid EMR Electricity Capacity Report" (United Kingdom)
15. Appendix 4.1-Manitoba Hydro Generation Planning Criteria

Attachment 3

Impact of Weather Variability in Peak Demand Forecast by Daymark

DAYMARK ENERGY ADVISORS

MEMORANDUM

To: Newfoundland Hydro

From: Daymark Energy Advisors

Date: October 17, 2018

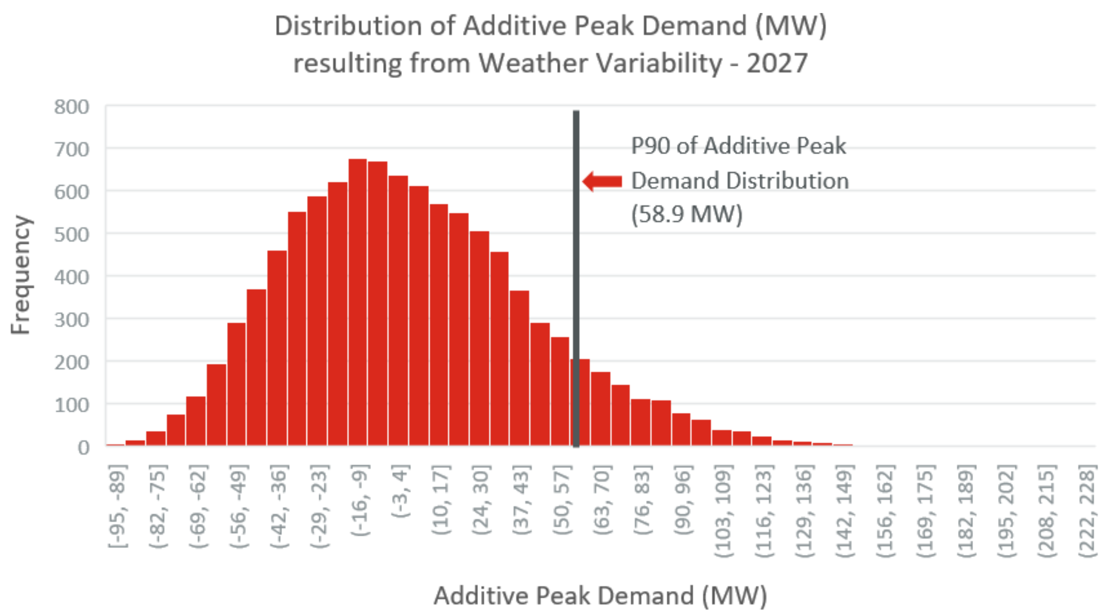
Subject: Load Forecast Uncertainty for Reliability Purpose

Summary

Daymark developed an estimate of the impact of representative historical weather variability on peak demand (MW) forecasts for the Island region because weather can be a critical driver of peak and thus impact reliability. The method explicitly accounts for such weather variability using Monte Carlo simulation. Specifically, probabilistic models were used to generate 10,000 possible future wind chill values for each year of the load forecast, that is for 2018 to 2037. These future possible windchill related values and the historic relationship between peak demand and the weather variable that was estimated using industry standard regression models, were then used to quantify the additive peak demand component associated with weather variability.

As an example of Daymark's effort, the chart below shows the distribution of additional peak demand as a result of the windchill variability in the Island's peak load forecast of 2027[1]. The distribution is based on 10,000 windchill simulations generated by Monte Carlo method with the variability observed in the historical windchill values. The figure also includes a vertical line within the distribution to represent P90 value of peak load uncertainty associated with windchill variability. For 2027 peak demand forecast, Daymark found P90 value to be 58.9 MW of the distribution associated with windchill related peak demand uncertainty. This is comparable to 60 MW value that NLH has been using to account for weather related peak demand forecast uncertainty in its modelling.

[1] The horizonal axis represents the range of additional peak demand resulting from different wind chill values generated from the simulation. And the vertical axis is the number of additional peak demand from 10,000 possible values falling in each range.



The method used to account for the impact of weather variability for reliability assessment is consistent with probabilistic methods used by NERC regions. Based on Daymark's research, NERC regions have incorporated load forecast uncertainty for reliability assessment purposes mainly by accounting for weather and/or economic and demographic variables. Most of the NERC regions have explicitly accounted for the variability associated with weather and economic variables via simulation methods. Few regions implicitly accounted for the uncertainties surrounding input variables used in the load forecast modeling and in the forecast trends by considering only the standard deviation of forecasted load. In addition, Daymark also found several regions considering the variability observed on historical hourly peak load to directly account for load forecast uncertainties.

Considering Weather Variability in Peak Demand Forecast

Daymark estimated the impact of historical weather variability on peak demand (MW) forecasts for the Island and Labrador regions in order to enhance the consideration of (and planning for) weather impacts on system reliability. The method recommended to improve NLH's peak forecast variability assessment relies on a two-step process – (1) utilizing the regression-estimated relationship between windchill and peak demand and (2) producing potential future windchill values by utilizing a probabilistic distribution. This memo describes the process used by Daymark in estimating the impact of weather variability on the peak demand forecast.

Relationship between peak demand and weather variable

To estimate the additive peak demand component due to weather variability for the Island forecast, Daymark evaluated the historic relationship between peak demand and the weather variable estimated by NLH in its load forecasting process. NLH uses historical windchill values as the weather variables in the Island's peak demand forecast regression methodology.

For the Labrador region, Daymark estimated the relationship between peak demand and weather variables using linear regression models. The regression equation was specified by relying on the square of the peak wind chill and adding a time trend variable. The squaring of peak wind chill is in line with peak demand forecasts specified in the NLH-developed load forecast methodology for the Island region. By squaring peak wind chill, the quadratic relationship between peak demand and peak wind chill is tested. A time trend variable is included in the model to account for time-dependent variables such as technology change that impact the Labrador regions' peak demand.

Probabilistic Model to simulate future wind chill values

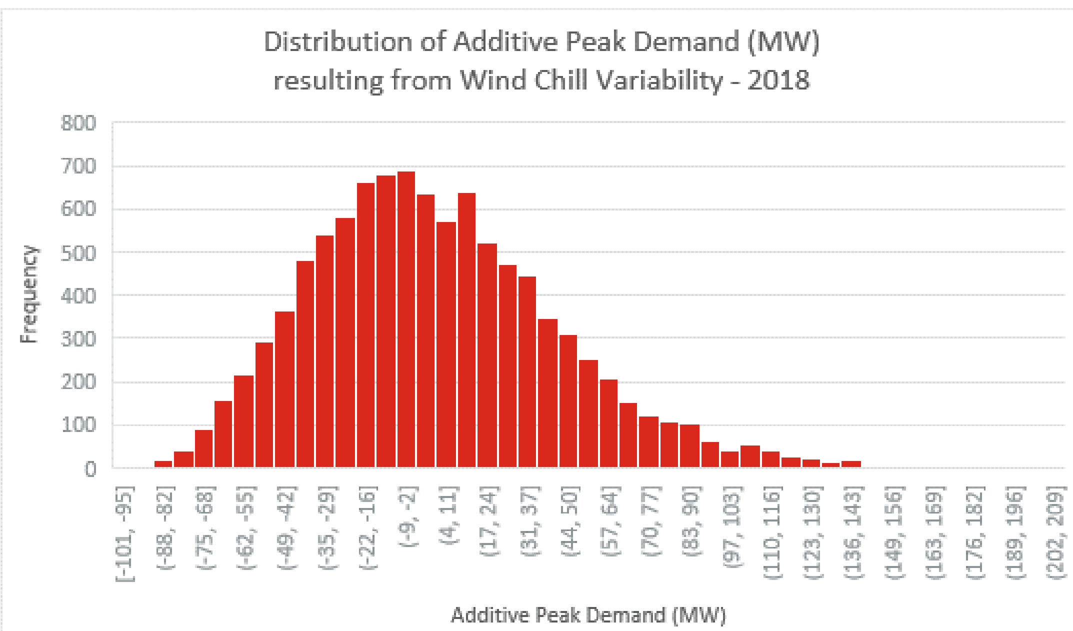
Daymark utilized probabilistic models to generate possible future wind chill values for each year of the load forecast period, 2018 – 2037. For each year, we simulated 10,000 possible wind chill values using Monte Carlo simulations[2]. The simulations assumed that the future wind chill values will have normal distributions with the mean and standard deviation based on the historical wind chill values of the same location. For example, while generating wind chill values for the Island region, the mean and standard deviation used in the Monte Carlo simulation is based on historical wind chill values from 1968 to 2017. The use of historical wind chill values to inform the distribution of possible future wind chill values helps account for the weather variations observed during the historical period. The uncertainty regarding

[2] **Monte Carlo simulation** produces distributions of possible outcome values. By using probability distributions, variables can have different probabilities of different outcomes occurring. Probability distributions are a much more realistic way of describing uncertainty in variables of a risk analysis. Source: Palisades.

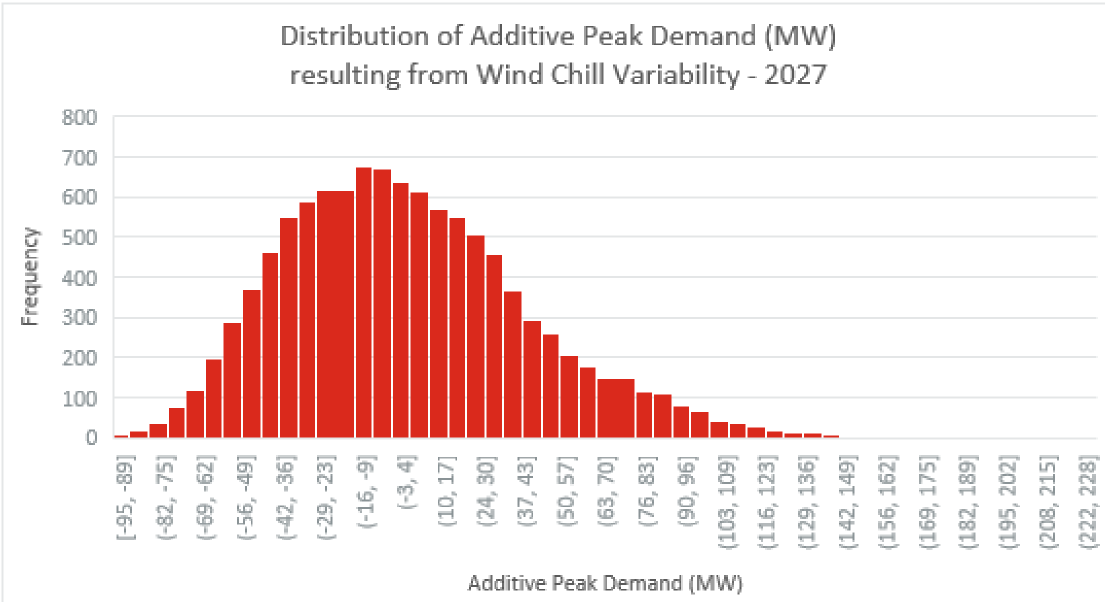
possible future wind chill values can be modeled using a normal distribution since the normal distribution often describes a variety of natural phenomena, such as temperature.

Estimating peak demand impact associated with weather variability

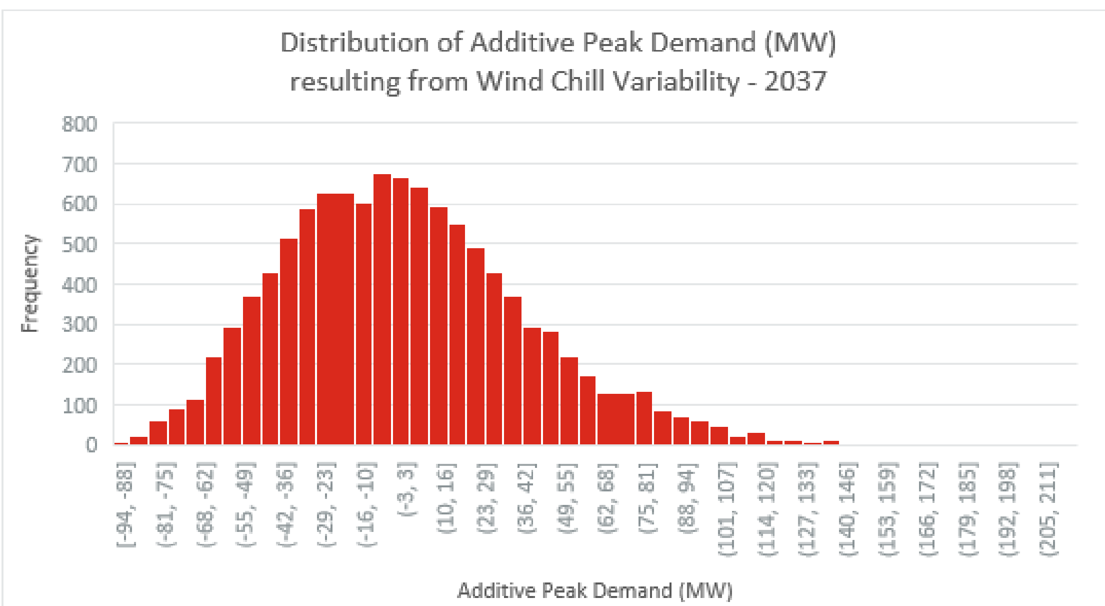
The next step in the process was to calculate the peak demand forecast associated with the wind chill values generated by the Monte Carlo simulations. Daymark used the regression-estimated relationship between peak demand and windchill and possible windchill values from the simulations for this purpose. Since the weather dependent load includes the overall impact of wind chill value on the peak demand forecast and our goal is to quantify the peak demand impact arising from the weather variability, we subtracted the average impact of windchill-dependent peak demand from the total peak demand load associated with each wind chill value. The resulting values for each year provide the distribution of the additive peak demand forecast associated with potential variations in the wind chill values from the average value. Below are the resulting distributions of the additive peak demand component for three years (2018, 2027, and 2037). The horizonal axis represents the range of additional peak demand resulting from different wind chill values generated from the simulation. And vertical axis is the number of additional peak demand from 10,000 possible values falling in each range.



(*Source: Excel File: "Load Forecast Impact - Trial-level - Peak Demand", Tab: "wchill_additive", Column B*)



(*Source: Excel File: "Load Forecast Impact - Trial-level - Peak Demand", Tab: "wchill_additive", Column K*)



(*Source: Excel File: "Load Forecast Impact - Trial-level - Peak Demand", Tab: "wchill_additive", Column U*)

Load Forecast Uncertainty for Reliability Assessment - Survey of NERC Regions

This memo summarizes methods used by NERC regions to incorporate load forecast uncertainty (LFU) for reliability assessment purposes. The provision of a continuous and reliable supply of electricity at the appropriate voltage and frequency is critical for any power system and therefore the reliability of services and resources is an important aspect of planning. Based on Daymark's research, we find that NERC regions have used one or more of the following methods to account for load forecast uncertainties.

- Explicitly accounting for weather and economic variables utilizing a simulation method.
- Considering standard deviations of forecasted load to account for variability surrounding the input variables used in the load forecast model and input forecast trends.
- Considering the variability based on historical observed hourly load data directly.

The table below provides a brief description of methods used by particular NERC regions to develop the base load forecast and then model load forecast uncertainty.

NERC Region	Description
NPCC	**Load Shape for Base Forecast:** The hourly load shape is based on a composite of historical load shapes of years 2002, 2003, and 2004. Specifically, January through March of the composite shape was based on the data for January through March of 2004. The months of April through September were based on those months for 2002, and October through December was based on the 2003 data. The base load shape was then adjusted through the forecast period to match the monthly or annual peak and energy forecasts. **Load Forecast Uncertainty:** The NPCC region considered the effects on reliability of uncertainties due to weather and economic conditions using a load forecast uncertainty model in GE's Multi-Area Reliability Simulation Software Program (MARS[3]). In addition, other regions within NPCC have also developed their own methodologies to account for load forecast uncertainties. *Maritimes*: Load Forecast Uncertainty is incorporated through two additional load models generated from the base load forecast by increasing the base load forecast by 4.6 and 9.2 percent for each year, values that represent one or two standard deviations, respectively. The 4.6% value is the standard deviation of load forecast errors from historical

[3] GE MARS is a system simulation program that models the generation system, the interconnections between areas, and the chronological hourly load demand. Source: GE Energy Consulting

	load forecasts and is based on the four-year lead time needed to add new resources. The forecast error is assumed to be approximately normally distributed around the forecast value. *Quebec:* The LFU model considers weather and load uncertainties. The weather-related uncertainty is based on a 46-year temperature base (1971-2016), which is adjusted by 0.30 degrees C per decade beginning in 1971 in order to include the impact of climate change. In addition, the load uncertainty is represented as a percentage of standard deviation over forecasted load and is considered to account for the uncertainties surrounding economic and demographic variables impacting the demand forecast and residual errors.
MRO – Sask Power	**Load Shape for Base Forecast:** The base load forecast is a 50/50 forecast.[4] Forecast for both energy and peak demand are drawn from a provincial econometric model and forecasted industrial load data. A weather normalization model is also utilized and features average daily weather conditions over the previous thirty years. The forecasted peak load is based on heating season and signifies the highest level of demand placed on the system. **Load Forecast Uncertainty:** Saskatchewan developed high and low forecasts by considering weather and economic variations using a Monte Carlo simulation. The model considered each variable to be independent from each other and assumed the probability distribution of occurrence to be normal. The probability of the load falling within high and low forecast bounds is expected to be at P90/P10 levels.[5]
MRO - Manitoba	**Load Shape for Base Forecast:** A 50/50 peak load forecast for a twenty-year period is developed. The annual load curve shape is based on the 8,760 hourly load records of a typical weather year. **Load Forecast Uncertainty:** The LFU model considered peak load multipliers to account for uncertainties associated with weather, economic, and forecast trends. It is assumed that the annual LFU is normally distributed with a 5% standard deviation in the assessment. The possible outcome of peak-load

[4] 50/50: A forecast level which has a 50% probability of being over or under the actual level.
[5] P10 for the probability of non-exceedance is a value such that 90% of the estimates exceed the P10 estimate
P90 for the probability of non-exceedance is a value such that 10% of the estimates exceed the P90 estimate

	multiplier is approximated based on a seven-step normal distribution each with different levels of probability.[6]
SPP	**Load Shape for Base Forecast:** SPP modelled a projected 8,760 hourly demand profile to provide load variability and volatility for chronological hours during simulation. The forecasted demand curve has its shape based on hourly load data for 2012. In addition, SPP adjusted the forecasted demand curve by a peak demand ratio calculated using hourly load data for the 2007-2012 period. **Load Forecast Uncertainty:** SPP considered the impact of weather and peak-load multiplier to account for load forecast uncertainty for the reliability assessment. The weather uncertainty is captured by analyzing the distribution of historical weather data for the SPP footprint. The peak-load multipliers are based on seven different monthly load patterns assumed for each area. The randomly selected load multipliers were determined by sampling from a uniform distribution and selecting one of seven possible monthly load patterns.
ERCOT	**Load Shape for Base Forecast:** The base energy forecast is based on an econometric model and utilizes weather, demographics, and time variables. ERCOT models each of its eight weather zones separately to account for the different load characteristics of each area. **Load Forecast Uncertainty:** The LFU considered the impact of weather and economic variables by simulating thirteen different load shapes based on thirteen historical weather years. In addition, five different economic growths are considered creating a resulting 65 load scenarios.
WECC	**Load Shape for Base Forecast:** The load forecasts developed for each assessment area include peak hourly load for the summer and winter of each year. Total internal demand projections are based on normal weather (50/50 distribution) and are provided on a coincident basis for most assessment areas. **Load Forecast Uncertainty:** To determine the distributions for the load forecast uncertainty, seven years of historical data (from 2007 to 2013) were used. Starting with the first hour of the year, the same hours for each of the three weeks prior to the given hour and for each of the three weeks following the given hour, as well as the current hour itself were used to determine the variability

[6] The seven-step normal distribution features seven different peak load multipliers and their associated probabilities. The highest and lowest peak load multiplier values (1.15 and 0.85 respectively) both have a probability of 0.0062.

	around the mean of the sample. This resulted in 49 points of data for each hour to calculate the distribution parameters.

Attachment 4

Migration to the PLEXOS® Modelling Platform

Migration to the PLEXOS® Modelling Platform

November 2018

A Report to the Board of Commissioners of Public Utilities

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1 Summary

Newfoundland and Labrador Hydro's ("Hydro") previous generation expansion modelling was supported by the Strategist modelling tool. In preparation for modelling the Newfoundland and Labrador Interconnected System, Hydro contracted the software original equipment manufacturer, Ventyx, to assist with extending the model to encompass the Newfoundland and Labrador Interconnected System. Through working with Ventyx, it became evident that the optimization methodology of the Strategist software was not capable of incorporating the complex modelling of the Labrador-Island Link ("LIL") and Hydro's cascading reservoir system. As such, Hydro determined that the Strategist tool could no longer appropriately support Hydro's modelling requirements and Hydro undertook the decision to acquire new modelling software.

The following primary drivers resulted in Hydro's selection of the PLEXOS® (Plexos) modelling tool:

1) Plexos is a state-of-the-art modelling tool also used by other Atlantic Canadian utilities, including Nova Scotia Power Inc. and New Brunswick Power Corp.;
2) The program can be used for purposes other than reliability modelling, such as expansion planning and cost reporting;
3) Plexos allows for integrated modelling of generation availability and transmission constraints. This will result in increased accuracy and conservatism as Hydro continues to evaluate and plan for its ability to maintain acceptable supply adequacy; and
4) Plexos has increased flexibility in modelling hydraulic resources, which are paramount in Hydro's current supply mix.

In the Strategist model, Hydro was limited to the use of the analytic convolution method to model uncertainty and resultant loss of load hours in its probabilistic assessment of supply adequacy. While the use of analytic convolution does have some advantages in terms of execution time, given the nature of the underlying mathematics it is not possible to integrate many of the constraints that exist in the power system explicitly in the model. For example, in

Hydro's future system, the use of analytic convolution would not allow for dynamic modelling of the various operational parameters of the LIL.

The use of Plexos allows Hydro to migrate from analytic convolution to the Monte Carlo simulation technique. While execution time for the Monte Carlo analysis is greatly increased over analysis performed using analytic convolution, there are significant benefits to adoption of the technique. The benefits include:

- The capability to dynamically model transmission constraints (i.e., the ability to load each pole of the LIL to 1.5 times rated capacity, the curtailment of the Emera Block in the case of a LIL outage, etc.);
- Ability to probabilistically model inputs used in modelling of:
    - load forecast uncertainty;
    - unit availability; and
    - Muskrat Falls plant capability;
- Ability to better interrogate results (i.e., for each simulation it is possible to determine both when and why a loss of load event occurred)

To determine the planning reserve margin for both the Newfoundland and Labrador Interconnected System and the Island Interconnected System, Hydro conducted multiple simulations of the system using the Monte Carlo simulation. It is Hydro's opinion that the benefits of the migration to Monte Carlo simulation offer a substantially improved understanding of the potential for supply disruption.

The following explains how the Strategist and Plexos modelling platform differ in terms of accuracy and conservatism when modelling the province's electrical system.

2 Load Shape

In developing a load shape, Strategist employed a processing tool to scale hourly data into representative weeks per month, defined in the program as "typical week per month".

Strategist would scale hourly data for the 744 hours in January into a typical 168-hour pattern that would then be applied across the full month. This created a fixed weekly profile for the month that would then be scaled to the monthly demand and energy forecast. Additionally, load modifiers would have to be included with similar profile (i.e., by representative week).

In contrast, Plexos preserves the hourly load profile, scaling all 8,760 hours of the year to the required demand and energy forecast, providing a much more representative load shape in the model. Plexos also allows for regional load modelling, allowing for accurate regional (i.e., provincial) and sub-regional (e.g., Island and Labrador, areas within Labrador, areas on the Island) load modelling. Lastly, load modifiers, for example load forecast uncertainty, are modelled as a load multiplier with a normal distribution. The combination of these enhancements allows for more accurate load forecast modelling.

3 Transmission

The Strategist modelling platform allowed for extremely limited support for the modelling of transmission constraints. In that modelling environment, it was possible that while the region would appear to satisfy all criteria, generation sources in the model could be transmission constrained, meaning that although there was generation available to the system, that generation could not be physically delivered to the load. The Strategist tool was also incapable of dynamically modelling the LIL.

Plexos allows for dynamically optimised transmission modelling, using a representation of the bulk transmission network[1] to ensure generation is capable to being delivered to load centres. It also allows for a forced outage rate and dynamic capabilities (e.g., monopole versus bipole characteristics) to be implemented for the LIL.

[1] The bulk transmission network is characterized by quadratic line loss equations as provided by Hydro's Transmission Planning department.

4 Hydroelectric Units

In Strategist, hydroelectric units were modelled as a fixed modifier to load, meaning that they were modelled as non-dispatchable resources in the simulation, with a forced outage rate modelled as a fixed deration in capacity, with monthly energy limitation. This resulted in limited flexibility. Plexos has the capability to model hydroelectric units as dispatchable generation with probabilistic forced outage rates and a daily energy limitation in addition to the monthly energy limitation, providing enhanced modelling of hydraulic resources.

5 Wind

Strategist modelled wind generation using a fixed generation profile; whereas Plexos uses a random generation profile that is based on actual generation probabilities derived from historic production data.[2]

6 Batteries

The Strategist modelling platform did not support the modelling of batteries. While battery generation does not currently exist in the province it has become a potential Resource Option to be considered as part of Hydro's long-term resource planning.

7 Capacity Assistance

With Strategist, capacity assistance contracts were modelled as a fixed load modifier. However Plexos has the capability of modelling the parameters of the applicable contracts including operational restrictions (e.g., number of calls, length of assistance provided, overall usage, etc.).

8 Forced and Planned Outage Modelling

The Strategist modelling platform used deterministic outage modelling, which creates an outage probability curve that is then compared to load. The Plexos modelling platform uses a

[2] Hydro used the historic production data to develop an Effective Load Carrying Capability Study, as described in Volume 1, Attachment 6.

Monte Carlo analysis, which consists of simulating system performance using a large sample size and a randomly selected outage profile. This process allows for more accurate modelling of system operations.

Attachment 5

Forced Outage Rate Methodology

Forced Outage Rate Methodology

November 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
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1 Summary

The forced outage rate methodology applied to the Reliability and Resource Adequacy Study varied by asset class, ownership, and condition. Forced Outage Rates ("FOR") were determined based on historical data where available or the most recent industry average. The historical data is based on a weighted average of Deration Adjusted Forced Outage Rate ("DAFOR") for hydroelectric units; and Derated Adjusted Utilization Forced Outage Probability ("DAUFOP") for gas turbine units. For units not owned by Hydro, Canadian Electricity Association ("CEA") or North American Electric Reliability Corporation ("NERC") industry standards were used. FOR assumptions will be re-evaluated on an annual basis to incorporate the most recent data available.

2 Hydroelectric Units

For Hydro-owned hydroelectric units (Bay d'Espoir, Cat Arm, Hinds Lake, Granite Canal, Upper Salmon, and Paradise River) a three-year capacity-weighted average was applied to these units for the near-term analysis, resulting in a DAFOR of 3.50%, while a ten-year capacity-weighted average was applied for use in the resource planning model resulting in a DAFOR of 1.93%. The DAFOR value was based on historical data which is reflective of Hydro's maintenance program over the long term. The long-term DAFOR was also applied to Muskrat Falls and Exploits units as it is assumed they will be maintained to the same standards. Once historical operational data from Muskrat Falls is available, the DAFOR will be re-evaluated.

For hydroelectric units not owned by Hydro (Rattle Brook, Newfoundland Power Hydro, and Deer Lake) the CEA G-ERIS[1] report, which collects outage statistics from utilities across Canada, was used to determine the DAFOR. This resulted in a value of 5.88%.[2] The DAFOR is based on a

[1] "Generation Equipment Status Annual Report – Equipment Reliability Information Systems" ("G-ERIS").
[2] "Generation Equipment Status Annual Report – Equipment Reliability Information System," Canadian Electricity Association, 2016, p.19.

five-year average. It was applied across all units in both the near- and long-term modelling and analysis.

3 Gas Turbines

As the gas turbines in the existing fleet are in varied condition, each was considered on an individual basis, rather than applying a weighted average across all units. For the Happy Valley Gas Turbine, a three-year capacity-weighted average was applied to the unit for the near-term analysis, resulting in a DAFOR of 13.92%, while a ten-year capacity-weighted average was applied for use in the resource planning model resulting in a DAFOR of 12.59%. The DAUFOP values were based on historical data founded upon the unit's past reliable performance. As the Holyrood Gas Turbine has only been in operation for the past three years, the near-term analysis considered performance in the worst case year of its operational history. For the long-term analysis, the average of the three years of operational data was applied for the unit, resulting in a long-term DAUFOP of 2.24%. For Hardwoods and Stephenville gas turbines, a DAUFOP of 30% was used for the near-term analysis, consistent with what was considered in Hydro's most recent latest Near-Term Generation Adequacy Report.[3]

4 Other

4.1 Corner Brook Pulp and Paper Cogen

A five-year average DAFOR of 9.70% was applied to both near- and long-term modelling and analysis. This value was based on the CEA G-ERIS report for thermal-biomass units.[4]

4.2 St. Lawrence and Fermeuse Wind Farms

The forced outage rate is included in the probability distribution for both near term and long term modelling and analysis.

[3] "Near-Term Generation Adequacy Report," Newfoundland and Labrador Hydro, May 2018.
[4] "Generation Equipment Status Annual Report – Equipment Reliability Information System" Canadian Electricity Association, 2016, p. 89.

4.3 Diesels

The Equivalent Demand Forced Outage Rate ("EFORd") of 5.83% from the NERC Generating Availability Data System ("GADS") Report was applied to all diesel units for the near term and long term modelling and analysis.[5,6] The EFORd is a measure used by NERC which is comparable to DAUFOP.[7]

4.4 Newfoundland Power Thermal

A five-year average DAUFOP of 15.80% was applied for all gas turbine units for both near- and long-term modelling and analysis. This value was obtained from the CEA G-ERIS report for combustion turbine units.[8]

4.5 Holyrood Thermal Generating Station

DAFORs of 15, 18, and 20% were applied to the Holyrood Thermal Generating Station in order to determine the sensitivity of the system to Holyrood availability in the near term. This is consistent with the most recent Near-Term Generation Adequacy Report filed with the Board of Commissioners of Public Utilities.[9]

5 Long-Term Resource Planning Study - Expansion Options

5.1 Hydroelectric Generation

Assumed DAFOR of 1.93% which is the same as Hydro-owned hydroelectric units used in the long term.

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[5] "2016 Generating Unit Statistical Brochure – Five Years (2012-2016), All Units Reporting," North American Electric Reliability Corporation (NERC), August 17, 2017, <https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx>
[6] As the Canadian Electricity Association does not track diesel forced outage rate, the NERC-GADS Report was used
[7] "IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity, IEEE Std 762™-2006" IEEE Power Engineering Society, March 15, 2007 <https://www.nerc.com/docs/pc/gadstf/ieee762tf/762-2006.pdf>
[8] "Generation Equipment Status Annual Report – Equipment Reliability Information System" Canadian Electricity Association, 2016, p. 102
[9] "Near-Term Generation Adequacy Report," Newfoundland and Labrador Hydro, May 2018.

5.2 Combustion Turbines and Combined Cycle Combustion Turbines

Both expansion options utilized a five-year average DAUFOP of 5.03%. This value was based on the CEA G-ERIS report for combustion turbines that are between 0-10 years old.[10]

5.3 Wind Generation

The forced outage rate for the wind generation option was included in the probability distribution.

5.4 Solar Generation

A forced outage rate of 0.5% was used as per consultant recommendation.[11]

5.5 Batteries

A forced outage rate of 0.5% was used as per consultant recommendation.[12]

[10] "Generation Equipment Status Annual Report – Equipment Reliability Information System" Canadian Electricity Association, 2016
[11] "NL Hydro Solar Generation Alternative Project Development Estimate," New Colliers Ltd., November 2, 2018 (refer to Volume. III, Attachment 6).
[12] "NL Hydro Battery Storage Alternative Project Development Estimate," New Colliers Ltd., November 2, 2018 (refer to Volume. III, Attachment 7).

Attachment 6

Effective Load Carrying Capability Study

Wind Turbines

Effective Load Carrying Capability Study

Newfoundland and Labrador Hydro Wind Turbines

November 2018

A Report to the Board of Commissioners of Public Utilities

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1 Summary

In 2007, Newfoundland and Labrador Hydro ("Hydro") secured two, 20-year Power Purchase Agreements for a total of 54 MW of wind generation on the island of Newfoundland; a 27 MW wind project located in St. Lawrence and a 27 MW project located in Fermeuse. The St. Lawrence Wind Farm is located approximately 5 km outside of the community of St. Lawrence on the Burin Peninsula. The farm is comprised of nine, 3.0 MW, Vesta V90 turbines, which have been in operation for nearly ten years. The project is owned and operated by Enel GP Newfoundland and Labrador Inc. and began producing wind power to the electricity grid in October 2008. The Fermeuse Wind Farm is located on the Southern Shore of the Avalon Peninsula. Similarly, the project consists of nine, 3 MW, Vestas V90 turbines which also have been in operation for almost ten years. The farm is owned by SkyPower and operated by EDF Énergies Nouvelles and began supplying wind energy in April 2009.

Wind generation is an intermittent, non-dispatchable resource, meaning its output cannot be controlled like a conventional resource as the output is dependent on the available wind speed. Production can also be challenging in times of very low or very high wind speeds. Low wind speeds may not reach the minimum wind speed required for the turbines to produce energy. Conversely, if wind speeds are too high, turbines may reach cut out speed, at which the turbines will shut down to prevent damage. Previously, under the Isolated Island System, Hydro has not relied upon wind farms as a reliable contribution to the islands firm capacity, meaning that wind generation was considered as purely energy on a planning basis.

Given the interconnection to the North American grid, as part of its Reliability Model, Hydro re-evaluated the contribution of wind generation to system capacity. Utilities across North America use a variety of methods to determine the capacity contribution of intermittent sources. A common approach is to use the concept of effective load carrying capability ("ELCC"). The ELCC of a unit is a measure of the additional load that the system can supply with the particular generator of interest, with no net change in reliability.

In order to determine the ELCC of the existing wind generation an ELCC study was performed. The ELCC study looked at the two existing wind farms on the island. It is assumed that new wind generation would have a similar generation profile to the existing wind farms. Therefore the ELCC determined in the study can be assumed to be applicable to all existing and new wind farms.

The ELCC study was completed using the PLEXOS model. The historical hourly wind generation data from January 2010 to June 2018 for both the Fermeuse and St. Lawrence wind farms was analyzed, resulting in a probability distribution for the wind generation in percentage by MW. The distribution was separated into winter (December to March) and non-winter (April to November) to more accurately determine the effect of the wind generation in the winter months where loss of load is more likely to occur. The distribution was then input into the PLEXOS model as a probability distribution representing each respective wind farm during the summer and winter periods. See Figure 1 to Figure 4 for the winter and non-winter generation profiles of each wind farm.

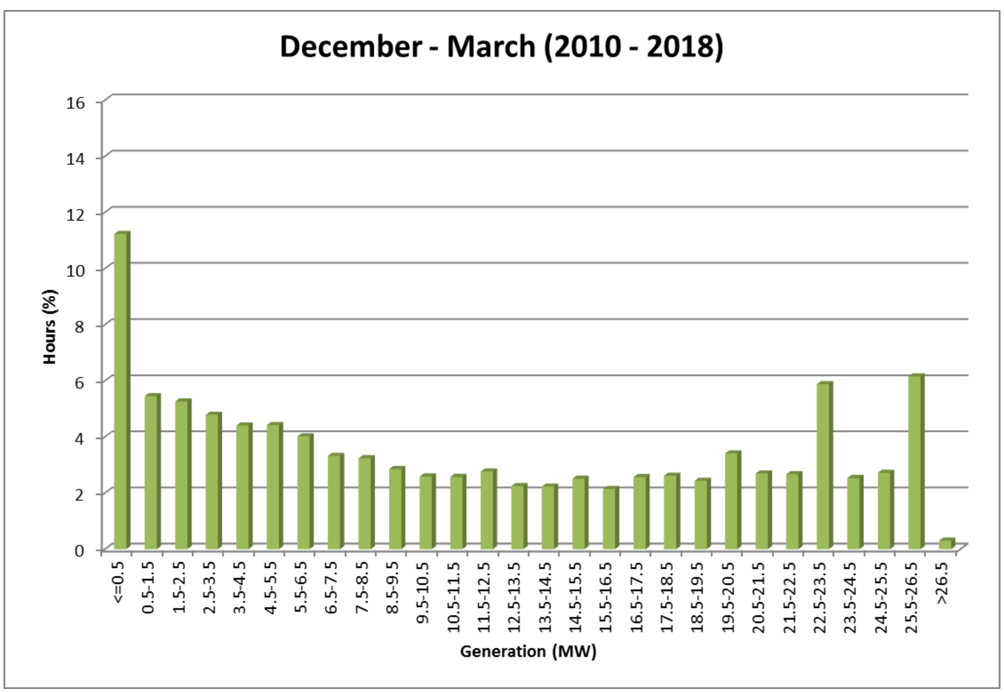

Figure 1: Fermuse Wind Farm Winter Generation Profile

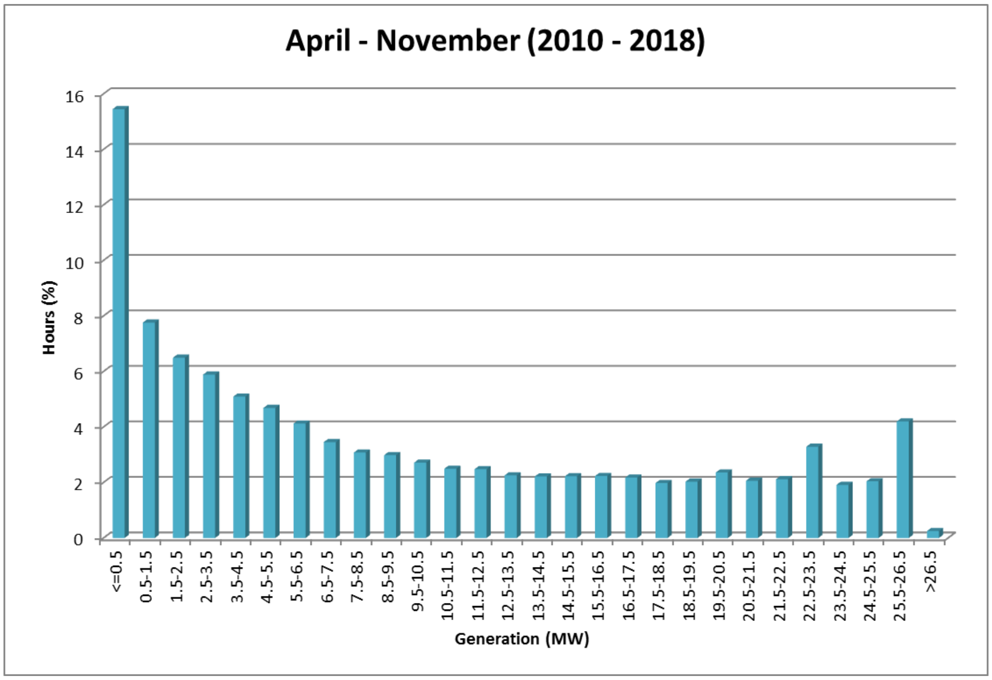

Figure 2: Fermuse Wind Farm Non-Winter Generation Profile

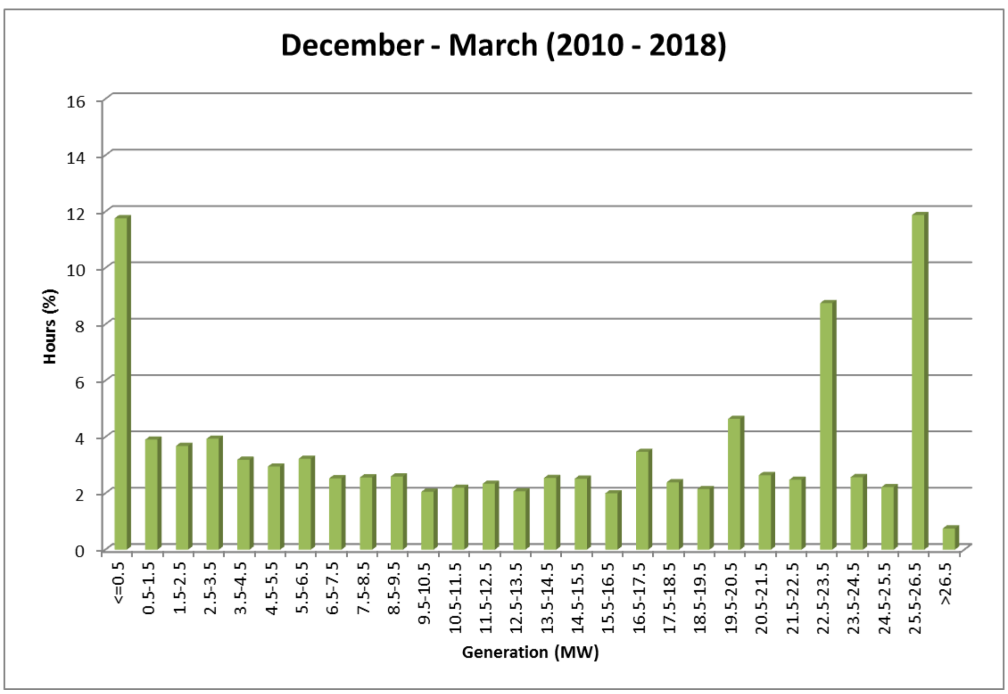

Figure 3: St. Lawrence Wind Farm Winter Generation Profile

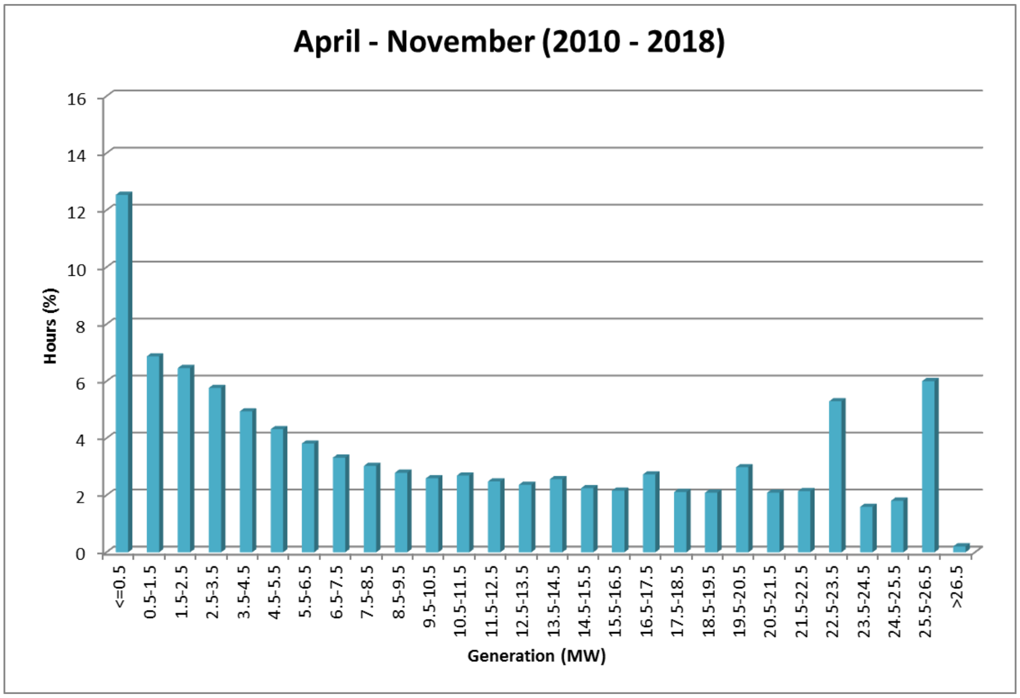

Figure 4: St. Lawrence Wind Farm Non-Winter Generation Profile

The steps taken to complete the ELCC study in PLEXOS® are as follows:

1) Run the model with both wind farms included in the system model. For this model, the wind farms were modeled using the probability curves described above.
2) Adjust loads using an escalator value in PLEXOS®, which linearly scales the system load, until the system loss of load hours ("LOLH") reaches 2.8 hours per year. Starting with a baseline LOLH of 2.8 allows the effect of changing generation resources to be clearly seen.
3) Remove both wind farms from the system and run the model again to determine the effect on system LOLH.
4) Add an "ideal" generator to the system with a capacity close to the expected ELCC value and rerun the model
5) Adjust the capacity of the ideal unit up or down and rerun the model until the system LOLH returns to 2.8.
6) The capacity of the ideal generator which produces a system LOLH of 2.8 determines the ELCC of the wind units.

The study found that the ELCC of the existing wind generators was approximately 12 MW, or 22%, based on an installed capacity of 54 MW.

Attachment 7

Technical Note on the Labrador-Island Link Reliability

TECHNICAL NOTE (FINAL)

Labrador-Island Link ("LIL") Reliability and Availability Assessment: Addendum - Updated CIGRE[1] HVdc Forced Outage Rates plus Statistics on Energy Availability (2018)

Introduction

The purpose of this technical note is to provide an update to the original LIL Reliability and Availability Assessment dated April 10, 2012 using 1985-2016 CIGRE HVdc system operational data with respect to the reliability and availability of the (+/-) 350 kVdc, 900 MW Bipolar, Line Commutated Converter ("LCC") HVdc transmission system known as the Labrador-Island Link ("LIL"). The original report was based on data from 1985-2008. The LIL will connect the Island Interconnected System on the Island of Newfoundland with Labrador for the purpose of supplying power and energy from hydroelectric generation at the Muskrat Falls Powerhouse located on the Churchill River downstream from the Upper Churchill Development. The intent of the Lower Churchill Project is to replace thermal generation at the Holyrood Thermal Generating Station with clean, renewable hydroelectric power from Labrador while meeting customer load growth and providing power and energy to Nova Scotia via the 500 MW Voltage Source Converter HVdc system known as the Maritime Link.

Muskrat Falls Submissions

The LIL HVdc reliability estimates were provided to the Commissioners of the Board of Public Utilities ("Board") via submission PUB-NLH-212 which provided an attachment titled, "Reliability & Availability Assessment of the HVdc Island Link," SNC Lavalin, April 10, 2012.

The SNC LIL reliability and availability assessment document makes reference to HVdc operating data published by CIGRE in the 2010 document "A Survey of the Reliability of HVdc Systems Throughout the World During 2007 – 2008," CIGRE, 2010. Since then, CIGRE has published three documents, one in 2012, 2014, and 2018.

[1] the Council on Large Electric Systems ("CIGRE").

nalcor energy
LOWER CHURCHILL PROJECT

TECHNICAL NOTE (FINAL)

The purpose of this document is to provide an addendum to the CIGRE data provided for input into the analysis in the above referenced document submitted to the Board. Specifically of interest is the Forced Outage Rate ("FOR") in percent for the LIL for input into Newfoundland and Labrador Hydro's generation planning software where annual energy unavailability and loss of load hours are calculated.

HVdc Reliability Data

The most comprehensive and up to date operational history of HVdc systems worldwide is provided by CIGRE which is an international non-profit association for promoting collaboration with experts from all around the world by sharing knowledge and joining forces to improve electric power systems of today and tomorrow. CIGRE has a study committee (B4) dedicated to publishing HVdc reliability data. Table 1 lists CIGRE's published documents on HVdc reliability.

Table 1: CIGRE Study Committee B4 HVdc Reliability Documents

Document Title	Document No.	Year Published	Operating Years
A survey of the reliability of HVdc systems throughout the world during 1985-1986	14_09_1988	1988	1986-1986
A survey of the reliability of HVdc systems throughout the world during 1986-1987	14_101_1990	1990	1986-1987
A survey of the reliability of HVdc systems throughout the world during 1995-1996	14_102_1998	1998	1995-1996
A survey of the reliability of HVdc systems throughout the world during 1997-1998	14_102_2000	2000	1997-1998
A survey of the reliability of HVdc systems throughout the world during 1999-2000	14_101_2002	2002	1999-2000
A survey of the reliability of HVdc systems throughout the world during 2001-2002	B4_201_2004	2004	2001-2002
A survey of the reliability of HVdc systems throughout the world during 2005-2006	B4_119_2008	2008	2005-2006
A survey of the reliability of HVdc systems throughout the world during 2007 – 2008	B4_209_2010	2010	2007-2008

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LOWER CHURCHILL PROJECT

TECHNICAL NOTE (FINAL)

Document Title	Document No.	Year Published	Operating Years
A survey of the reliability of HVdc systems throughout the world during 2009-2010	B4_113_2012	2012	2009-2010
A survey of the reliability of HVdc systems throughout the world during 2011-2012	B4_117_2014	2014	2011-2012
A survey of the reliability of HVdc systems throughout the world during 2015-2016	B4_137_2018	2018	2015-2016

Overall HVdc System Reliability

The reliability of the LIL is a combination of the components that make up the system as a whole. This will include the converter stations, overhead lines ("OHL"), subsea cables and electrode lines. The CIGRE data provides insight mainly on the converter operational reliability. Data for this analysis uses information gathered from two-terminal HVdc systems with one converter per pole, not unlike the design of the LIL.

Reliability Definitions – CIGRE

Energy Availability ("EA"): The amount of energy that could have been transmitted over the HVdc system, if not limited by the forced and scheduled outages of the various components of the HVdc Link (converter station equipment dc lines and/or cables).

Forced Energy Unavailability ("FEU"): The amount of energy that could not have been transmitted over the dc system due to forced outages. The CIGRE B4.04 WG only considers converter station equipment outages and not the dc line or cables.

Scheduled Energy Unavailability ("SEU"): The amount of energy that could not have been transmitted over the dc system due to scheduled outages. The CIGRE B4.04 WG only considers converter station equipment outages and not the dc line or cables.

Reliability Definitions – Nalcor Energy

Forced Outage ("FO"): The state in which equipment is unavailable for normal operation but is not in the scheduled outage state (i.e., an outage which is not a scheduled outage).

Maximum Continuous Capacity ("Pm"): The maximum bipolar HVdc system capacity (MW) for which continuous operation under normal conditions is possible referred on to the dc bus at the normal rectifier station (i.e., maximum power transfer with redundant cooling in operation).

Outage Capacity ("Po"): The capacity reduction in MW, which the outage would have caused if the HVdc system was operating at its Pm at the time of the outage.

Outage Derating Factor ("ODF"): The ratio of outage capacity to Pm.

$$ODF = Po/PM$$

Actual Outage Duration ("AOD"): The time elapsed in hours between the start and the end of an outage. The time shall be counted to the nearest tenth of an hour. Time less than a tenth of an hour shall be counted as having a duration of a tenth of an hour.

Equivalent Outage Duration ("EOD"): The AOD in hours, multiplied by the ODF so as to take account of partial loss of capacity. Each actual outage duration may be classified according to the type of outage involved [i.e., equivalent forced outage duration ("EFOD") and equivalent scheduled outage duration ("ESOD")].

$$EOD = AOD\ x\ ODF$$

Period Hours ("PH"): The number of hours in the reporting period. In a full year the PH are 8760 hours (8784 hours for a leap year). If the equipment is commissioned part way through a year the period hours will be proportionately less than 8760 hours.

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Actual Outage Hours ("AOH"): The sum of actual outage durations within the reporting period. The AOH may be classified according to the type of outage involved (i.e., AFOH and ASOH).

$$AOH = \Sigma \cdot AOD$$

Equivalent Outage Hours ("EOH"): The sum of all equivalent outage durations within the reporting period. The equivalent outage hours may be classified according to the type of outage involved (i.e., EFOH and ESOH). If outage duration overlaps the beginning or end of a reporting period, only the EOD, which lie within the reporting period, shall be included in EOH.

$$EOH = \Sigma \cdot EOD$$

Energy Unavailability ("EU"): EU is a measure of the energy at which could not have been transmitted due to (scheduled and forced) outages.

Energy Availability ("EA"): A measure of the energy at which could have been transmitted except for limitations of capacity due to outages, arising from any cause, either forced or scheduled.

Energy Unavailability %: $EU = \frac{EOH}{PH} x\ 100$

Forced Energy Unavailability %: $FEU = \frac{EFOH}{PH} x\ 100$

Scheduled Energy Unavailability %: $SEU = \frac{ESOH}{PH} x\ 100$

Energy Availability

Energy availability is the amount of energy that could have been transmitted over the HVdc system, if not limited by the forced and scheduled outages of the various components of the HVdc Link (converter station equipment dc lines and/or cables.

Table 2 summarizes the EA, FEU, and SEU for the past ten years and represents approximately 900 years of HVdc operating experiences. Detailed CIGRE energy availability statistics can be found in Appendix C.[2]

Table 2: Historical HVdc EA, FEU, and SEU Data[3]

Year	EA	FEU	SEU
2005	94.49	2.38	2.35
2006	93.44	3.70	2.39
2007	93.20	1.57	3.62
2008	93.83	2.32	3.59
2009	92.99	3.02	3.75
2010	91.82	3.23	3.82
2011	95.02	0.30	3.60
2012	93.64	0.88	3.90
2013	93.27	0.74	5.15
2014	92.34	1.27	5.48
2015	93.59	2.56	3.39
2016	93.44	2.53	3.54
Average	93.42	2.04	3.71

[2] Source: “A survey of the reliability of HVdc systems throughout the world during 2015-2016,” CIGRE, 2018, Table I
[3] Average values and may not sum to 100%.

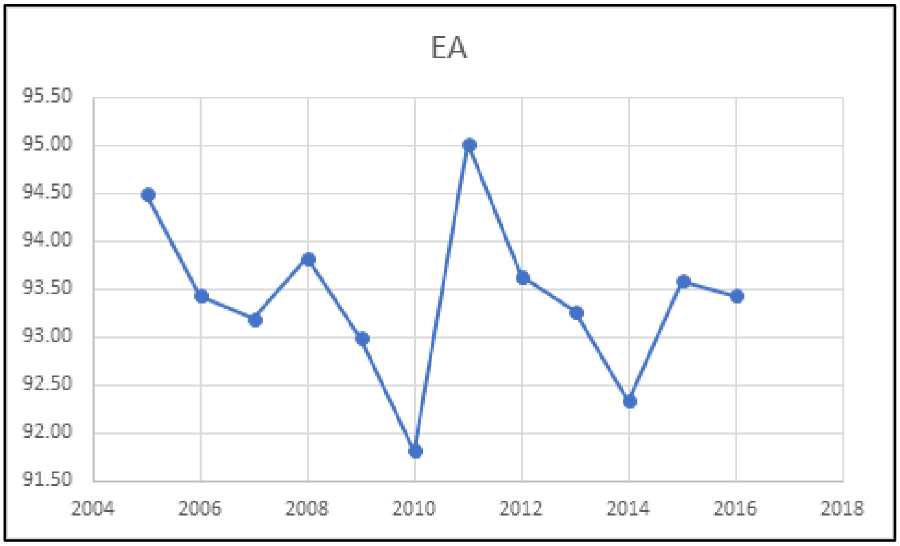

Figure 1: Graphical Representation of EA as Presented in Table 2

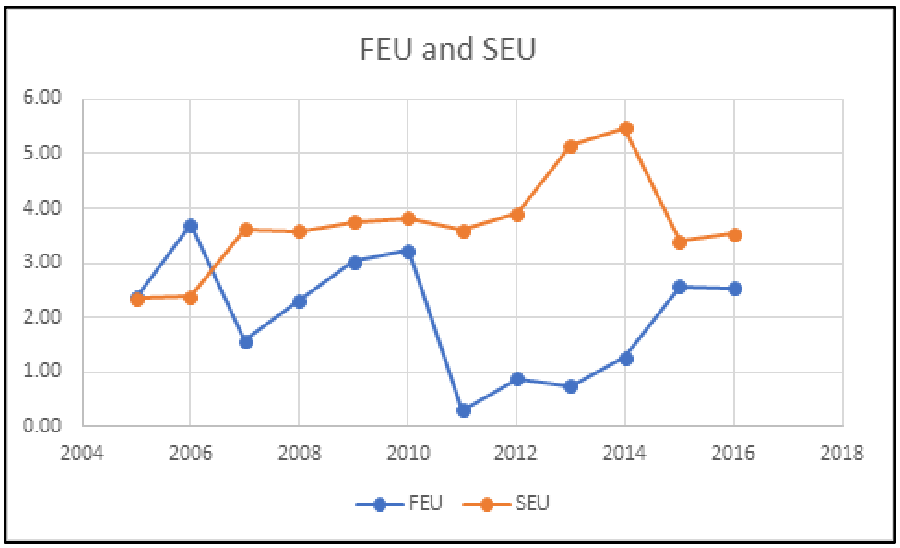

Figure 2: Graphical Representation of FEU/SEU as Presented in Table 2

One should note that although cable failures should not be considered in the calculation of forced outage rates, they are included in the energy unavailability. The values above also include a significant number of transformer failures. In an effort to better reflect the expected and designed reliability of the LIL during normal operation, a number of HVdc systems which reported energy availability less than 80%[4] were removed from the average.

If one filtered the HVdc systems per reporting year with an energy availability of less than 80%, this would result in the removal of 33 reporting links from a total of 453 (7.3%) reporting from 2005 to 2011.

Table 3: Historical HVdc EA – Outliers Removed

Year	EA - Base	EA – 80%[5] Cut-off	Difference
2005	94.49	96.77	2.28
2006	93.44	96.48	3.04
2007	93.20	95.62	2.42
2008	93.83	95.46	1.63
2009	92.99	95.29	2.3
2010	91.82	96.64	4.82
2011	95.02	96.37	1.35
2012	93.64	95.27	1.63
2013	93.27	96.02	2.75
2014	92.34	95.99	3.65
2015	93.59	95.51	1.92
2016	93.44	95.33	1.89
Average	93.42	95.90	2.48

The filtering of reporting HVdc systems with EA values above 80% resulted in an overall annual average difference of 2.48% as shown in Table 3. These outliers are indicative of HVdc systems which have experienced long term failures due to converter transformers and other equipment for which no spares were on hand.

[4] Indicative of a long-term failure or scheduled outage reducing capacity to zero.
[5] Selected as a reasonable cut-off point for HVdc Systems EA reporting for CIGRE.

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The LIL has been constructed with the most modern equipment and technology, design techniques and has been planned from sanction to be highly reliable due to adequate redundancies and critical spare parts. Therefore, the LIL is expected to have an EA well above 80% and should not suffer from CIGRE data collected from HVdc systems which are inherently less reliable.

Forced Outage Rates ("FOR")

CIGRE has provided sufficient HVdc operational data for development of key performance indicators for two-terminal, single converter per pole stations. A list of the HVdc system data which was used for this analysis is provided in Table 4.

Table 4: CIGRE List of Two-Terminal, One Converter per Pole HVdc Systems

Two-Terminal, 1 × 12 Pulse Converter Per Pole HVdc Systems	
Skagerrak 1 & 2	Grita (1)
Skagerrak 3 & 4 (1)	Talcher-Kolar
Square Butte	Gui-Guang Bipole 1
CU	Gui-Guang Bipole 2
Gotland 2 & 3	EstLink 1 (1)
Konti Skan 2 (1)	EstLink 2 (1)
Fenno-Skan 1 (1)	NorNed (1)
Fenno-Skan 2 (1)	SAPEI
Rihand-Dadri	Caprivi (3)
SACOI (2)	Storebaelt (3)
New Zealand Pole 2 (3)	Ballia-Bhiwadi
New Zealand Pole 3 (3)	Yun Guang
Kontek (1)	WATL (3)
SwePol (1)	EATL (3)
Kii Channel	NER-Agra
Tiang-Huang	Malaysia-Thailand

Notes: (1) Monopolar System
(2) Three-Terminal Monopolar System
(3) One Pole

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As a result, the FOR in % and Forced Unavailability or downtime ("FU") in hours per year can be calculated. For the purposes of this document, the FOR percent is calculated as:

$$FOR(\%) = \left(\frac{FU}{8760}\right) x\ 100$$

$$Where, FU = f_{(p\ or\ b)} x\ d_{(p\ or\ b)}$$

Table 5 lists the FOR and FU for pole and bipole outages For 2007/2008, 2011/2012, 2015/2016 and the average from 1985 to 2016. These stats are for the converter complete with valves, converter transformers, smoothing reactors filters etc. The data used for these calculations is found in Appendix A.

Table 5: Summary of FOR and FU (per Terminal)

Period	Outage	FOR (%)	FU (hrs/year
2007	Pole	0.15	13
	Bipole	0.0003	0.02
2008	Pole	0.38	34
	Bipole	0.0002	0.02
2011	Pole	0.18	15.68
	Bipole	0.03	3.05
2012	Pole	0.72	63.02
	Bipole	0.001	0.13
2015	Pole	0.32	27.64
	Bipole	0.003	0.28
2016	Pole	0.56	49.04
	Bipole	0.06	5.43
1985-2016	**Pole**	**0.56**	**48.68**
	Bipole	**0.01**	**1.13**

LIL Pole Outages

Pole outages in this case are focused on the converter stations themselves rather than a combination of converter, OHL, subsea cables, and electrode lines. The breakdown of average FEU for LCC equipment category is shown in Figure 3.

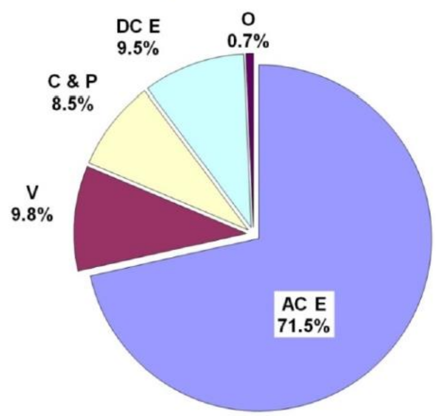

Figure 2
Breakdown of Average FEU by
Equipment Category of All Reporting LCC
HVDC Systems (1983-2014)

Figure 3: Breakdown of Average FEU by Equipment Category (LCC)[6]

The categories defined in Figure 3 are defied as:

Table 6: CIGRE Equipment Types

ac Filter and Shunt Bank	AC-E.F
ac Switchyard Equipment	AC-E.SW
ac Control and Protection	AC-E.CP
Converter Transformer	AC-E.TX
Synchronous Compensator	AC-E.SC
ac and Auxiliary Equipment	AC-E.AX
Valve Electrical	V.E
Valve Cooling (integral with valve)	V.VC
Local HVdc Control and Protection	C-P.L
Master HVdc Control and Protection	C-P.M
Telecommunication	C-P.T
dc Filters	DC-E.F
dc Switching Equipment	DC-E.SW
dc Ground Electrode	DC-E.GE
dc Ground Electrode line	DC-E.EL
Other dc Yard and Valve Hall Equipment	DC-E.O
dc Transmission Line	TL

[6]Source: “A survey of the reliability of HVdc systems throughout the world during 2015-2016,” CIGRE, 2018.

Data collected from CIGRE and shown in Table 7 summarizes the average frequency and duration of pole outages on HVdc systems worldwide which are of a two-terminal design with one converter per pole. This data is an average of data collected from these HVdc systems between 1985 and 2016.

Therefore, based on the data one can expect between 0.09 (1 in 11.1 years) and 8.75 pole outages per pole per year with outage durations between 0.8 and 123.2 hours. As the LIL is an LCC bipole HVdc system and consists of two poles, one can expect between 0.18 (1 in 5.56 years) and 17.5 pole outages a year. On average, one can expect 2.45 pole outages per pole per year with an average duration of 19.89 hours. Therefore, it can be expected that the LIL will have on average 4.9 pole outages per year with an average duration of 19.89 hours.

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Table 7: Summary of Frequency and Duration of Forced Pole Outages

Two-Terminal Systems – 1 × 12 Pulse Converter per Pole Average 1985-2016			
System	**Years in Service**	f_p	d_p
Gotland 2 & 3	28	0.41	33.3
Fenno-Skan 1 (1)	27	2.72	23.8
Square Butte	26	2.65	21.5
CU	26	1.49	5
Skagerrak 1 & 2	25	1.45	15.1
New Zealand Pole 2 (3)	25	1.9	3.1
SACOI (2)	24	3.93	3
Rihand-Dadri	20.6	3.1	53.3
Konti Skan 2 (1)	18	2.75	3.8
Kii Channel	16	0.09	123.2
SwePol (1)	14	3.64	16.2
Kontek (1)	13	1.04	8.1
Grita (1)	13	2.81	20.5
Talcher-Kolar	11	2.8	5.9
Malaysia-Thailand	9.3	6.59	11.2
NorNed (1)	8	1.25	81
Fenno-Skan 2 (1)	5	1.1	6.3
Ballia-Bhiwadi	5	2.6	4.1
EstLink 1 (1)	4	4	25.2
SAPEI	4	1.13	7.5
Storebaelt (3)	3.3	2.1	2
New Zealand Pole 3 (3)	3	1	2.1
EstLink 2 (1)	3	1.17	65.1
Caprivi (3)	3	4.33	2.3
Skagerrak 3 & 4 (1)	1	2	4.2
Tiang-Huang	1	0.25	4.1
Gui-Guang Bipole 1	1	0.5	0.8
Gui-Guang Bipole 2	1	0	0
Yun Guang	1	0.25	4.3
WATL (3)	1	6	44.1
EATL (3)	1	4.5	12.3
NER-Agra	1	8.75	24.2
Average	-	2.45	19.89

Notes: (1) Monopolar System
(2) Three-Terminal Monopolar System
(3) One Pole

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Bipole Outages

Pole outages in this case are focused on the converter stations themselves rather than a combination of converter, OHL, subsea cables, and electrode lines.

Table 8: Summary of Frequency and Duration of Forced Bipole Outages (1985-2016)[7]

Two-Terminal Systems – Single and Multiple Converters per Pole Average 1985-2016			
System	**Years in Service**	**f_b**	**d_b**
Gotland 2 & 3	28	0.21	1.7
Nelson River BP2	28	0.18	2.8
Hokkaido-Honshu	**28**	**0.04**	**163.1**
Square Butte	26	0.65	5.5
CU	26	0.25	2.1
Skagerrak 1 & 2	25	0.2	5.3
Itaipu BP1	24	0.12	1.3
Itaipu BP2	24	0.08	2.1
Nelson River BP1	21	0.12	5.7
Rihand-Dadri	20.6	0.73	1.2
Konti Skan 2 (1)	18	0.5	3
Kii Channel	16	0	0
Talcher-Kolar	11	0.23	6.1
Ballia-Bhiwadi	5	1	19.3
SAPEI	4	0.25	10.9
Skagerrak 3 & 4 (1)	1	0	0
Tiang-Huang	1	0	0
Gui-Guang Bipole 1	1	0	0
Gui-Guang Bipole 2	1	0	0
Yun Guang	1	0	0
NER-Agra	1	0	0
Cahora Bassa	1(2)	0.5	2.2
	Average	0.23	10.56(3)
	Average (Ignoring Hokkaido-Honshu)	0.24	3.29

Notes: (1) Monopolar System
(2) 1 year reporting, 41 years in service

[7] Source: "A survey of the reliability of HVdc systems throughout the world during 2015-2016,"CIGRE, 2018, Table V (B).

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CIGRE bipole outage data collected from the 2018 reliability survey identifies a frequency (f_b) between 0.08 and 0.73 bipole outages per year for an average time (d_b) of 1.2 to 19.3(163.1) hours. Therefore, Table 8 would indicate the LIL would experience on average 0.23 bipole outages per year or 1 outage in 4.34 years for an average duration of 10.56 hours.

It should be noted that the Hokkaido-Honshu HVdc system has reported a substantial outage time of 163.1 hours which would appear erroneous. Going back in to the CIGRE data, the last reported outage on the Hokkaido-Honshu Link is in 1995. Between 1995 and 2009, the d_b is reported as 324.5 hours and drops to 163.1 hours. Based on this inconsistency, it is recommended to ignore this data point in the analysis and assume an average bipole outage of 0.24 (1 in 4.17 years) for an average duration of 3.29 hours.

Overhead Line Reliability

Table 9 outlines HVdc overhead line performance data as published in Table II of CIGRE HVdc reliability surveys provided from three publications between 2012 and 2018.[8] On average, one can expect 1.27 outages per pole for an average duration of 18.94 hours.

Table 9: Summary of Forced Outages and Durations for Overhead Lines

System	2009		2010		2011		2012		2015		2016		Average (2009-2016)	
	#	Duration	#	Duration	#	Duration	#	Duration	#	Duration	#	Duration	#	Duration
Skagerrak 1 & 2	0	0.0	0	0.0	1	13.9	1	1.8	-	-	-	-	0.5	3.93
Square Butte	0	0.0	2	86.5	3	96.7	1	78.2	0	0.0	4	188.1 [(1)]	1.67	74.92
CU	-	-	-	-	1	105.6	0	0.0	0	0.0	0	0.0	0.25	26.40
New Zealand Pole 2	2	37.0	2	3.4	0	0.0	0	0.0	0	0.0	0	0.0	0.67	6.73
Nelson River BP1	1	0.0	1	0.4	4	4.0	2	0.2	2	0.4	0	0.0	1.67	0.83
Nelson River BP2	5	3.7	2	0.3	1	0.1	4	0.3	3	0.5	2	0.2	2.83	0.85
												Average	1.27	18.94

Notes: [(1)] Converter Transformer

[8] **Sources:**
"A survey of the reliability of HVdc systems throughout the world during 2011-2012," CIGRE, 2014, Table II.
"A survey of the reliability of HVdc systems throughout the world during 2009-2010," CIGRE, 2012, Table II.
"A survey of the reliability of HVdc systems throughout the world during 2015-2016," CIGRE, 2018, Table II.

Table 10: Forced Outage Rates and Durations (Historical Data)[9]

System	Length (km)	Reporting Period (yrs)	km-yrs	No. of Outages	f/100km/yr/pole	Average Duration (hrs)
Pacific Intertie	847	8	6776	51	0.376	1.48
Nelson River BP1	960	11	10560	45	0.213	0.53
Nelson River BP2	960	11	10560	41	0.194	0.52
Square Butte	749	9	6741	5	0.037	1.69
CU	710	11	7810	6	0.038	4.72
Itaipu-1	1200	6	7200	21	0.146	2.06
Itaipu-2	1200	3	3600	10	0.139	0.24
IPP	784	3	2352	18	0.383	2.96
				Average	**0.191**	**1.78**

Using the historical data retrieved from Table 10 for the LIL route length of 1,100 km, the expected reliability performance would be 2.101 outages per pole per year with an average repair time of 1.78 hours per outage. Therefore, the unavailability and FOR is 0.0425% per pole.

As a result, the common mode failure of both OHL poles must be calculated. It is assumed this failure is ten times less likely to occur, however the repair time would be substantially longer. Therefore, a common mode failure of both OHLs is assumed to be 0.02 f/100km/yr. Further information related to the calculation of the OHL reliability data can be found in "Reliability and Availability Assessment of the HVdc Island Link," SNC Lavalin, April 10, 2012, Section 2.2, (Appendix B).

Submarine Cable Reliability

Key reliability statistics for the submarine cable from Table 11 were gathered from "Iceberg Risk to Subsea Cables in the Strait of Belle Isle," C-CORE, June 2011. These values were also provided in "Reliability & Availability Assessment of the HVdc Island Link," SNC Lavalin*,* April 10, 2012, (Appendix B).

[9] Source: "Reliability and Availability Assessment of the HVdc Island Link," SNC Lavalin, April 10, 2012, Table 2-4.

Other cable failures due to fishing and shipping activity in the area are assumed to be 1/50 years or 0.02 failures per year. The design of the Strait of Belle Isle crossing includes a spare submarine cable which can be switched in to replace a failed cable. Therefore, the probability of losing a single cable due to a cable fault is the sum of the independent failure of two cables plus the probability of an iceberg striking two cables.

Table 11: Iceberg Strike Failure Rates[10]

Cable Failure	Probability (f/year)
Single Cable	0.004
Two Cables	0.002
Three Cables	0.001

Cable repair times in the Strait of Belle Isle are assumed to take six months or 4,380 hours. To increase reliability across the Strait of Belle Isle, a total of three submarine cables were installed on the seabed. Under normal operation, two cables are connected a single OHL with the third connected to the other pole.

As shown in "Reliability and Availability Assessment of the HVdc Island Link," SNC Lavalin, April 10, 2012, Section 2.3 (Appendix B), this evaluates to a failure rate of 0.00022 f/yr for the independent failure of two cables and 0.002 f/yr due to iceberg strikes, for a total failure rate of 0.0022 f/yr with an average repair time of 4,163 hrs/outage and an average downtime of 9.24 hours/year. This corresponds to an FOR of 0.105%.

For the complete loss of the link, it is assumed an iceberg strike on all three submarine cables is the cause. It is calculated this failure mode has a rate of 0.001 f/yr with an average repair time of 4,380 hours/outage and an average downtime of 4.38 hours/year (An FOR of 0.05%).

[10] Source:"Iceberg Risk to Subsea Cables in the Strait of Belle Isle" C-CORE, June 2011.

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Electrode Line Reliability

For the purposes of this analysis, it has been determined that the impact of electrode line failures has no significant impact on the overall reliability of the LIL. This statement was made in "Reliability and Availability Assessment of the HVdc Island Link," SNC Lavalin, April 10, 2012, Section 2.4 (Appendix B).

Composite HVdc System

Figure 4 outlines the reliability model for the LIL and provides a basis for calculating the overall reliability performance indicators for the LIL.

HVdc Overhead Line/Submarine Cable

The composite reliability performance indicators for a single HVdc pole and submarine cable are shown in Table 12. All data has been taken directly from "Reliability & Availability Assessment of the HVdc Island Link," SNC Lavalin, April 10, 2012. Please refer to Section 3.1 of the referenced report for detailed explanation and calculations (Appendix B).

Table 12: Composite Reliability Performance of One Pole of the HVdc and Submarine Cable[11]

Table 3-1: Reliability Performance of One Pole of the HVdc Line

Element	Failure Rate (f/yr)	Repair Time (hrs)	Downtime (hrs/yr)
L1-388 km	0.741	1.78	1.32
C-Submarine cable	0.0022	4,163	9.24
L2-680 km	1.3	1.78	2.31
Total	2.042	6.3	12.87

[11] Source: "Reliability & Availability Assessment of the HVdc Island Link," SNC Lavalin, April 10, 2012,, Table 3-1.

The composite reliability of both poles in an independent failure mode is:

$$\lambda_t = (2.042)^2 . \frac{(2 \; x \; 6.3)}{8760} = 0.006 \; f/yr$$

$$r_t = \frac{(6.3)^2}{(2 \; x \; 6.3)} = 3.15 \; hrs$$

$$U_t = 0.006 \; x \; 3.15 = 0.019 \; hrs/yr$$

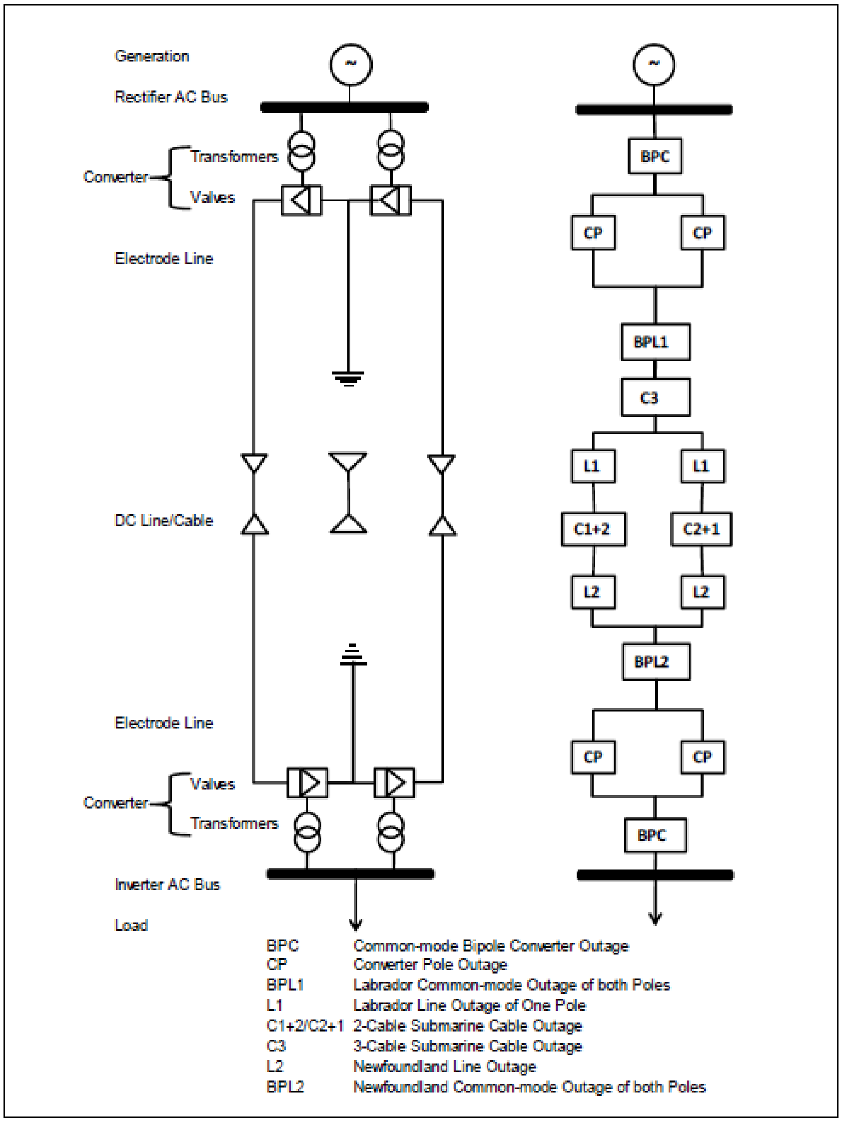

Figure 4: LIL Reliability Model

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Converters

Similarly using the reliability indices for converter pole and bipole failures as shown in Table 13, one can calculate the coincident independent failure of the converters as:

$$\lambda_t = (2.45)^2 \frac{(2\ x\ 19.89)}{8760} = 0.0273\ f/yr$$

$$r_t = \frac{(19.89)^2}{(2\ x\ 19.89)} = 9.95\ hrs$$

$$U_t = 0.0273\ x\ 9.95 = 0.272\ hrs/yr$$

Table 13: Reliability Performance Indicators for LIL Converters (Average to 2016)

Outage	FOR (%)	FU (hrs/year)	F/yr	Repair Time (Hours)
Pole	0.556	48.731	2.45	19.89
Bipole	0.0098	0.86	0.25	3.44

Complete HVdc Reliability Model

If we consider the failure of both lines/cables (P1+P2) or both converters (CP+CP), in series with the common-mode failure of both poles due to converter faults (BP) and main line faults (BPL1 and BPL2), the composite reliability of the LIL can be determined. The variable which has the largest impact on the LIL availability is the repair time for a tower failure on the OHL.

The repair time is heavily dependent on the severity and location of the failure. Tables 14 to 17 calculate the LIL unavailability in hours per year for the composite HVdc bipole system for 1-, 3-, 7-, 14-, and 21-day repair times.

Table 14: Composite LIL Bipole Reliability Performance Indicators – 24 Hour Line Outage

Element	Failure Rate (f/yr)	Repair Time (hrs)	LIL Unavailability (hrs/yr)
BP-MFA	**0.25**	**3.44**	**0.86**
CP+CP-MFA	**0.0273**	**9.95**	**0.272**
BPL1-388 km	0.074	**24**	**1.78**
P1+P2	0.007	621.7	4.3519
BPL2-680 km	0.13	**24**	**3.12**
CP+CP-SOP	**0.0273**	**9.95**	**0.272**
BP-SOP	**0.25**	**3.44**	**0.86**
Total	**0.7656**	**696.48**	**11.511**

Table 15: Composite LIL Bipole Reliability Performance Indicators – 72 Hour Line Outage

Element	Failure Rate (f/yr)	Repair Time (hrs)	LIL Unavailability (hrs/yr)
BP-MFA	**0.25**	**3.44**	**0.86**
CP+CP-MFA	**0.0273**	**9.95**	**0.272**
BPL1-388 km	0.074	**72**	**5.328**
P1+P2	0.007	621.7	4.3519
BPL2-680 km	0.13	**72**	**9.36**
CP+CP-SOP	**0.0273**	**9.95**	**0.272**
BP-SOP	**0.25**	**3.44**	**0.86**
Total	**0.7656**	**792.48**	**21.30**

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Table 16: Composite Lil Bipole Reliability Performance Indicators – 1 Week Line Outage

Element	Failure Rate (f/yr)	Repair Time (hrs)	LIL Unavailability (hrs/yr)
BP-MFA	**0.25**	**3.44**	**0.86**
CP+CP-MFA	**0.0273**	**9.95**	**0.272**
BPL1-388 km	0.074	**168**	**12.432**
P1+P2	0.007	621.7	4.3519
BPL2-680 km	0.13	**168**	**21.84**
CP+CP-SOP	**0.0273**	**9.95**	**0.272**
BP-SOP	**0.25**	**3.44**	**0.86**
Total	**0.7656**	**984.48**	**40.89**

Table 17: Composite LIL Bipole Reliability Performance Indicators – 2 Week Line Outage

Element	Failure Rate (f/yr)	Repair Time (hrs)	LIL Unavailability (hrs/yr)
BP-MFA	**0.25**	**3.44**	**0.86**
CP+CP-MFA	**0.0273**	**9.95**	**0.272**
BPL1-388 km	0.074	**336**	**24.864**
P1+P2	0.007	621.7	4.3519
BPL2-680 km	0.13	**336**	**43.68**
CP+CP-SOP	**0.0273**	**9.95**	**0.272**
BP-SOP	**0.25**	**3.44**	**0.86**
Total	**0.7656**	**1,320.48**	**75.16**

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Table 18: Composite LIL Bipole Reliability Performance Indicators – 3 Week Line Outage

Element	Failure Rate (f/yr)	Repair Time (hrs)	LIL Unavailability (hrs/yr)
BP-MFA	**0.25**	**3.44**	**0.86**
CP+CP-MFA	**0.0273**	**9.95**	**0.272**
BPL1-388 km	0.074	**504**	**37.30**
P1+P2	0.007	621.7	4.3519
BPL2-680 km	0.13	**504**	**65.52**
CP+CP-SOP	**0.0273**	**9.95**	**0.272**
BP-SOP	**0.25**	**3.44**	**0.86**
Total	**0.7656**	**1,656.48**	**109.44**

Table 19: Composite LIL Bipole Reliability Performance Indicators - Summary

OHL Average Repair Time (Tower Failure)		Failure Rate	Total Repair Time	LIL Unavailability		LIL Availability
Day(s)	Hours	(f/yr)	(hrs)	(hrs/yr)	(%/year)	(%/year)
1	24	0.7656	696.48	11.511	0.1314	99.87
3	72	0.7656	792.48	21.30	0.2432	99.76
7	168	0.7656	984.48	40.89	0.4668	99.53
14	336	0.7656	1,320.48	75.16	0.8580	99.14
21	504	0.7656	1,656.48	109.44	1.2493	98.75

Referencing Table 14 and Table 18, the composite forced unavailability of the LIL (FOR) is [(11.511/8760) x 100%] = 0.131% for a one-day line outage and 1.25% for a three-week line outage. Table 19 summarizes the LIL availability depending on the assumed average repair time of the HVdc OHL. As a result, the calculated availability of the LIL is 98.75% for a three-week line outage and 99.87% for a 24-hour line outage. One should keep in mind that this availability metric determines the time in which the full capacity of the LIL is available. Pole outages, converter outages or scheduled outages for maintenance will force the operation of the LIL into a monopole configuration to a maximum continuous pole rating of 1.5 pu or 675 MW.

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CIGRE RELIABILITY INDICIES (2010 vs 2018)

In an effort to understand any significant changes in the CIGRE reliability indices due to addition of modern HVdc systems after 2008, a comparison of the average bipole and pole outage frequency and duration up to 2008 and 2016 is shown in Table 20. It should be noted that an additional 19, two-terminal HVdc systems with a single converter per pole were reporting outage data to CIGRE in 2016. As a result an additional 169 operating years were logged.

Table 20: Comparison – Historical Average CIGRE Data to 2008 and 2016

CIGRE Forced Outage Data - Two-Terminal Systems - 1 Converter per Pole									
Average to 2008					Average to 2016				
Total Reporting Years	Pole		Bipole		Total Reporting Years	Pole		Bipole	
	f_p	d_p	f_b	d_b		f_p	d_p	f_b	d_b
173.00	2.01	59.73	0.21	1.29	342.20	2.45	19.89	0.25	3.44

It is clear from the data that the average FOR of a single pole up to 2016 increased from 2.01 per year to 2.45 per year; while the duration of these outages decreased from an average of 59.73 hours to 19.89 hours. The frequency of bipole outages increased marginally with the 2016 operational data from 0.21 per year (1 in 4.8 years) to 0.25 per year (1 in 5 years). The duration of bipole outages increased from 1.29 hours to an average of 3.44 hours.

Conclusions

To summarize the results of the updated CIGRE reliability statistical analysis, one can conclude:

1) Energy Availability: Based on CIGRE data from 2005 to 2016, which comprises of over 900 years of in-service HVdc projects, an EA of 93.42% is calculated. This EA takes into account both forced and scheduled outages and it also includes monopole and back to back schemes. For the LIL, a pole outage effectively reduces the power capacity from 900 MW to 675 MW, which reduces the energy availability by 25%. An outage of any major component reduces the energy availability to 0%. Please note, that EA is not the

same as the calculated availability of HVdc Link. The calculated availability of the HVdc link considers the full capacity of the LIL only and is based on FOR and average outage times for particular converter configurations.

Results of the updated CIGRE data and further detailed statistical analysis for the LIL has concluded:

1) Pole Outage: Based on the analysis, one can expect between 0.18 (1 in 5.56 years) and 17.5 pole outages a year. On average, one can expect 2.45 pole outages per pole per year with an average duration of 19.89 hours. Therefore, it can be expected that the LIL will have on average 4.9 pole outages per year with an average duration of 19.89 hours.
2) Bipole Outage: The analysis would indicate the LIL would experience on average 0.24 bipole outages per year or 1 outage in 4.17 years for an average duration of 3.29 hours. It should be noted that the GE GRID specification calls for a bipole forced outage frequency of no more than 1 in 10 years or 0.1.
3) Complete HVdc Reliability model: The updated report included the latest CIGRE data and did not update the values for the transmission system. Furthermore, the average FOR (0.7656 f/yr) was utilized and combined with the average outage time (75.16 hrs) to give an overall availability of the LIL's 900 MW capacity rating of 99.14% (based on a two-week OHL repair time). This value does not consider the amount of energy transmission capacity lost or scheduled outages. For example during outages of a pole converter due to routine maintenance, the LIL will be reconfigured into a monopole configuration with total maximum pole rating of 675 MW or 1.5 p.u. The HVdc link is still available at a reduced capacity, which has no impact on the calculated availability of the LIL but does affect the EA.

Appendix A

Summary of CIGRE HVdc Reliability Data (2011-2016)[12]

[12] Developed from CIGRE Documents, B4-117 Table V(B) & B4-137 Table V(B)

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APPENDIX A

Table A-1: Summary of CIGRE HVdc Survey Data between 2011 and 2016[13]

System	2011				2012				2015				2016				Average to 2016				
	Pole		Bipole		Pole		Bipole		Pole		Bipole		Pole		Bipole		Years in Service	Pole		Bipole	
	f_p	d_p	f_b	d_b	f_p	d_p	f_b	d_b	f_p	d_p	f_b	d_b	f_p	d_p	f_b	d_b		f_p	d_p	f_b	d_b
2 Terminal Systems - 1 Converter Per Pole																					
Skagerrak 1 & 2	1.50	2.10	0.00	0.00	0.75	8.40	0.50	4.00	-	-	-	-	0.25	3.50	1.50	14.60	25.00	1.45	15.10	0.20	5.30
Skagerrak 3 & 4 (1)	2.50	7.50			3.00	2.70			-	-	-	-	2.00	4.20	0.00	0.00	1.00	2.00	4.20	0.00	0.00
Square Butte	1.50	11.50	3.50	8.50	3.50	3.10	1.00	1.40	2.50	42.20	0.50	3.80	1.50	450.40	1.00	24.60	26.00	2.65	21.50	0.65	5.50
CU	1.50	10.10	0.00	0.00	1.25	16.00	0.00	0.00	0.50	1.90	0.00	0.00	0.25	2.30	0.00	0.00	26.00	1.49	5.00	0.25	2.10
Gotland 2 & 3	0.75	16.60	0.50	3.00	0.25	34.30	0.00	0.00	0.50	1.80	0.00	0.00	0.50	1.40	0.50	1.80	28.00	0.41	33.30	0.21	1.70
Konti Skan 2 (1)					0.50	0.20			-	-	-	-	3.50	5.60	-	-	18.00	2.75	3.80	0.50	3.00
Fenno-Skan 1 (1)	6.50	19.90			4.50	240.10			5.00	6.00	-	-	2.00	5.70	-	-	27.00	2.72	23.80	-	-
Fenno-Skan 2 (1)					1.00	12.80			0.00	0.00	-	-	2.00	6.40	-	-	5.00	1.10	6.30	-	-
Rihand-Dadri	0.50	37.40	0.50	0.60	0.75	1.10	0.00	0.00	4.00	5.70	0.50	0.30	1.50	18.40	0.00	0.00	20.60	3.10	53.30	0.73	1.20
SACOI (2)	3.33	6.10			0.67	11.70			2.67	8.40	-	-	1.33	4.10	-	-	24.00	3.93	3.00	-	-
New Zealand Pole 2 (3)	2.00	2.70			1.50	3.10			1.50	2.70	-	-	0.50	0.60	-	-	25.00	1.90	3.10	-	-
New Zealand Pole 3 (3)									1.50	2.60	-	-	0.50	0.40	-	-	3.00	1.00	2.10	-	-
Kontek (1)	2.00	0.80							-	-	-	-	0.50	1.90	-	-	13.00	1.04	8.10	-	-
SwePol (1)									2.50	0.80	-	-	2.50	2.00	-	-	14.00	3.64	16.20	-	-
Kii Channel	0.00	0.00	0.00	0.00	0.25	241.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.09	123.20	0.00	0.00
Tiang-Huang									0.25	4.10	0.00	0.00	-	-	-	-	1.00	0.25	4.10	0.00	0.00
Malaysia-Thailand									21.50	10.20	-	-	9.00	16.00	-	-	9.30	6.59	11.20	-	-
Grita (1)	0.50	3.30			3.50	1.70			1.50	9.60	-	-	9.50	7.70	-	-	13.00	2.81	20.50	-	-
Talcher-Kolar	1.00	3.30	0.50	17.80	2.25	2.50	0.00	0.00	0.75	1.70	0.50	0.50	3.00	3.50	0.00	0.00	11.00	2.80	5.90	0.23	6.10
Gui-Guang Bipole 1									0.50	0.80	0.00	0.00	-	-	-	-	1.00	0.50	0.80	0.00	0.00
Gui-Guang Bipole 2									0.00	0.00	0.00	0.00	-	-	-	-	1.00	0.00	0.00	0.00	0.00
EstLink 1 (1)									6.00	3.00	-	-	3.00	1.80	-	-	4.00	4.00	25.20	-	-
EstLink 2 (1)									1.50	147.10	-	-	0.50	1.50	-	-	3.00	1.17	65.10	-	-
NorNed (1)	0.50	7.90			1.50	8.00			0.50	3.80	-	-	1.00	3.30	-	-	8.00	1.25	81.00	-	-
SAPEI									1.25	2.80	0.50	3.40	2.50	10.40	0.00	0.00	4.00	1.13	7.50	0.25	10.90
Caprivi (3)									-	-	-	-	4.00	2.30	-	-	3.00	4.33	2.30	-	-
Storebaelt (3)	2.50	3.50			3.50	1.00			-	-	-	-	1.00	2.00	-	-	3.30	2.10	2.00	-	-
Ballia-Bhiwadi					2.25	0.80	0.00	0.00	1.50	0.80	2.00	0.40	1.25	16.70	1.00	94.80	5.00	2.60	4.10	1.00	19.30
Yun Guang									0.25	4.30	0.00	0.00	-	-	-	-	1.00	0.25	4.30	0.00	0.00
WATL (3)									-	-	-	-	6.00	44.10	-	-	1.00	6.00	44.10	-	-
EATL (3)									-	-	-	-	4.50	12.30	-	-	1.00	4.50	12.30	-	-
NER-Agra									-	-	-	-	8.75	24.20	0.00	0.00	1.00	8.75	24.20	0.00	0.00
Average	1.77	8.85	0.71	4.27	1.82	34.65	0.19	0.68	2.44	11.32	0.36	0.76	2.14	22.88	0.40	13.58	**342.20**	**2.45**	**19.89**	**0.29**	**3.94**
Notes:	(1)	Monopolar System																			
	(2)	Three Terminal Monopolar System																			
	(3)	One Pole																			

[13] Developed from CIGRE Documents, B4-117 Table V(B) & B4-137 Table V(B), Frequency and Duration of Forced Outages for 2 Terminal Systems – 1 Converter per Pole.

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APPENDIX B

Appendix B

Nalcor Energy LCP Document
ILK-SN-CD-8000-EL-SY-0004-01
Reliability & Availability Assessment of the HVdc Island Link

Document Front Sheet

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NE-LCP Contractor/Supplier

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NE-LCP or EPC(M)

REVIEW DOES NOT CONSTITUTE APPROVAL OF DESIGN DETAILS, CALCULATIONS, TEST METHODS OR MATERIAL DEVELOPED AND/OR SELECTED BY THE CONTRACTOR, NOR DOES IT RELIEVE THE CONTRACTOR FROM FULL COMPLIANCE WITH CONTRACTUAL OR OTHER OBLIGATIONS.

- [x] 01 – REVIEWED AND ACCEPTED – NO COMMENTS
- [ ] 02 – REVIEWED – INCORPORATE COMMENTS, REVISE AND RESUBMIT
- [ ] 03 – REVIEWED - NOT ACCEPTED
- [ ] 04 – INFORMATION ONLY
- [ ] 05 – NOT REVIEWED

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Lower Churchill Project

RELIABILITY & AVAILABILITY ASSESSMENT OF THE HVdc ISLAND LINK

SLI Document No.: 505573-480A-47ER-0017-00

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1 INTRODUCTION

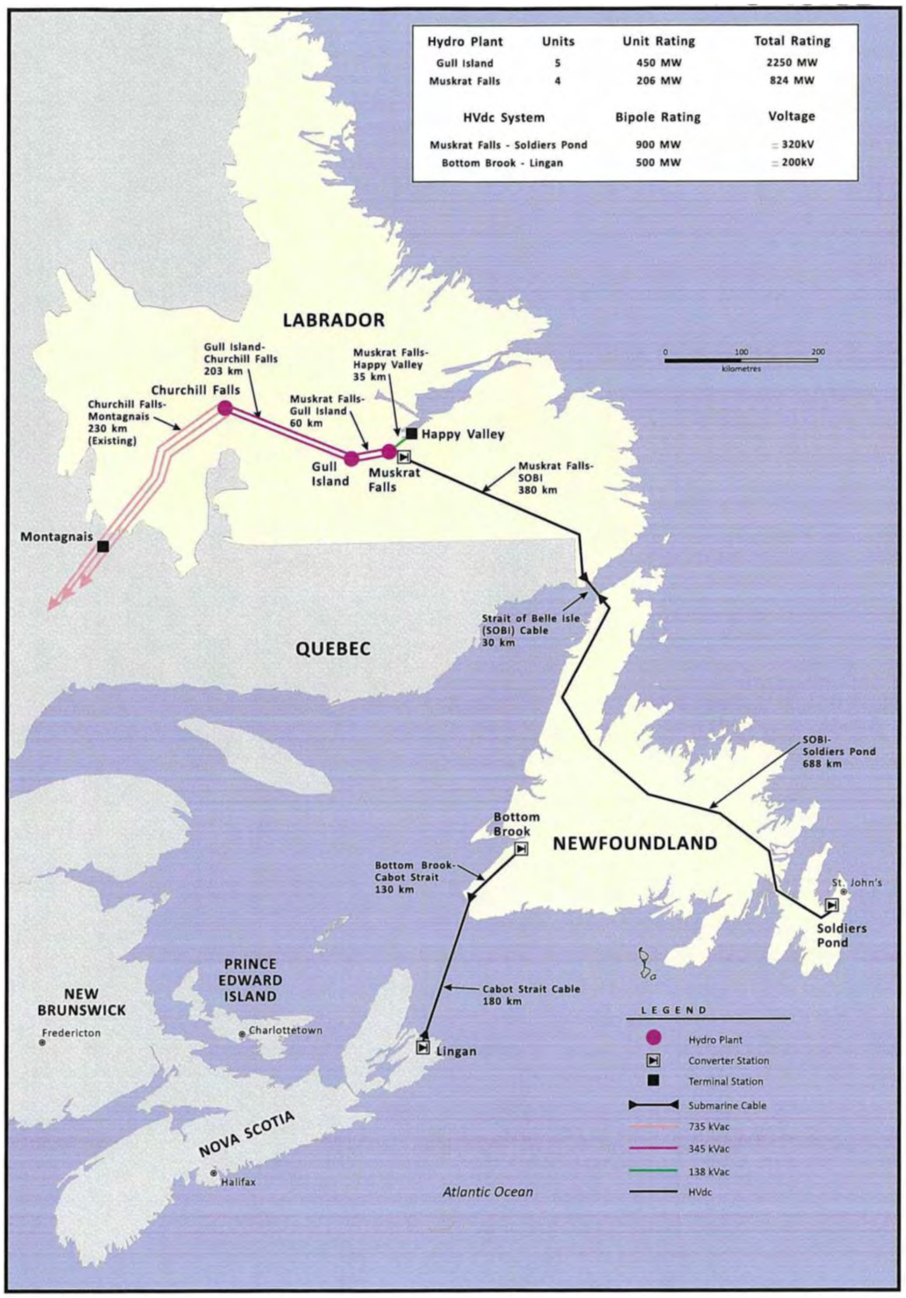
1.1 Overview of the System

This Report presents the results of the reliability and availability analysis carried out to determine the expected performance of the ±350 kV, 900 MW HVdc interconnection between Muskrat Falls and Soldiers Pond (Island Link) [1]. The Maritime Link between Bottom Brook and the Nova Scotia power system was not considered in this study. The results consider the performance of each element of the Island Link as well as the composite reliability of the complete link from Muskrat Falls to Soldiers Pond.

Figure 1-1 provides an overview of the project area.

The assessment considered only the Island Link from the ac bus at the converter station in Muskrat Falls to the ac bus at the Soldiers Pond converter station. The generation at Muskrat Falls, the 315 kV interconnection to Churchill Falls and the synchronous condensers at Soldiers Pond were not included in this assessment since their influence on the reliability of the link itself is considered to be negligible. The number and rating of the synchronous condensers at Soldiers Pond was determined from the steady-state and transient stability analyses and an economic assessment considering single contingency outages of equipment.

Figure 1-1: Project Area Map



1.2 Objectives of the Studies

The objectives of this Reliability and Availability (R&A) Assessment are:

- To develop R&A performance indices for the converter stations
- To develop R&A performance indices for the HVdc transmission line from Muskrat Falls to Soldiers Pond
- To assess the R&A performance indices of the submarine cables from Forteau Point to Shoal Cove,
- To develop R&A performance indices for the electrode lines from Muskrat Falls to L'Anse au Diable and from Soldiers Pond to Dowden's Point
- To assess the improvements that could be made in the above indices considering design aspects such as the provision of spare equipment, over-rated equipment, etc.
- To assess the composite R&A performance indices of the complete HVdc Island Link from Muskrat Falls to Soldiers Pond

2 COMPONENT RELIABILITY

This section examines the reliability indicators available for the individual elements within the Island Link: HVdc converter stations, HVdc overhead line, HVdc transition compounds, HVdc submarine cables and electrode lines. An explanation of the reliability calculations used in this assessment is provided in Appendix A.

2.1 HVdc Converter Stations

A major input to this assessment was the information compiled by CIGRE on the performance of HVdc converter stations covering 158 terminal-years over the period 1988-2008[2] and the information contained in the PTI report R-64-81 [3]. For the 2-terminal, single-converter-per-pole stations, the following key performance indicators were determined:

- Forced Outage Rate (FOR) in %
- Forced Unavailability or downtime (FU) in hours/year

These indices are for the complete converter including valves, converter transformers, smoothing reactors, filters, etc. The following table summarizes the results, which are shown in detail in Appendix B:

Table 2-1: Summary of FOR and FU (per terminal)

Period	Outage	FOR (%)	FU(hrs/yr)
2007	Pole	0.15	13
	Bipole	0.0003	0.02
2008	Pole	0.38	34
	Bipole	0.0002	0.02
1988-2008	Pole	0.49	43.4
	Bipole	0.003	0.27

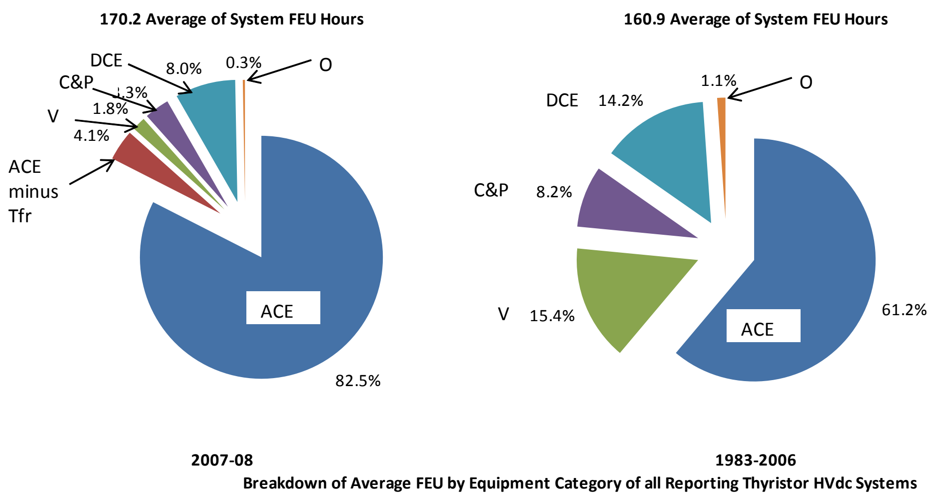
The average failure rate per terminal over the period 1988-2008 for pole outages was 2 failures/terminal/year; with an average repair time of 21 hours. The corresponding values for bipole outages were 0.2 failures/terminal/year and 1.3 hours.

Thus, for a 2-terminal bipole, the estimated average reliability indicators would be:

- 4 pole outages per year with a repair time of 21 hours per outage (FOR=0.98%)
- 0.4 bipole outages per year with a repair time of 1.3 hours per outage (FOR=0.006%)

The same source also provides information on the breakdown of forced energy unavailability (FEU) into the major components of a converter station: ac equipment and auxiliaries (ACE), thyristor valves (V), dc equipment (DCE), control & protection (C&P) and others (O) as shown in Figure 2-1.

Figure 2-1: Forced Energy Unavailability (FEU) as reported by CIGRE



The data for 2007-2008 indicate that the major contributors to the energy unavailability of the converter stations are the converter transformers, followed by the dc smoothing reactors. The provision of a spare unit for these major equipment items greatly improves the availability of the complete converter station, as shown in the following illustrative example.

Spare Converter Transformer

λ = Failure rate (1-phase) = 0.01 f/yr

N = No. of Components = 6

R_1 = Repair Time (replacement with spare) = 168 hrs

R_2 = Repair Time at Factory = 4380 hrs

With no spare,
Average outage time per pole
= 0.01x3x4380 = 131 hrs/yr

With one spare (for 6 single phase units),
Effective outage time per outage
= $R_1+R_2/2 \times [N \lambda R_2/(8760+N \lambda R_2)]$ = 168+64 = 232 hrs
Average outage time per pole
= 0.01x3x232 = 7 hrs/yr

Almost all recent HVdc converter stations have been built with a spare transformer unit of each type and a spare smoothing reactor per terminal. The impact of this design measure is shown by the following CIGRE statistics:

Table 2-2: Converter Unavailability

Item		Performance Indicator		
Spare Transformer		No	Yes	Yes
Spare Smoothing Reactor		No	No	Yes
Terminal	Unavailability	3.04%	0.94%	0.21%
	Hours/ Year	266	82.5	18.6

Based on the above information, it is recommended that a spare transformer unit of each type and a spare smoothing reactor be provided at each terminal of the Island Link. With spare units at each terminal, the reliability performance indicators of the converter stations can be taken as the average of the 2007 and 2008 statistics from Table 2-1 above since the most recent converter stations were designed with spare units.

Table 2-3: Converter Reliability (Average 2007-2008)

Outage	FOR (%)	FU(hrs/yr)	F/yr	Repair Time (hrs)
Pole	0.265	24	1.64	13.8
Bipole	0.00025	0.02	0.24	0.13

With the continuing improvements in the technology and design of converter stations, it would not be unreasonable to expect lower failure rates and repair times for the Muskrat Falls and Soldiers Pond converters. However, for the purpose of this analysis it was considered prudent to use the historical information from the recent past as this would give more conservative results. Insufficient information is available in the historical records to allow for a distinction to be made between each converter at either end of a dc link, one of which may be in a remote area. In the case of the Island Link, the Soldiers Pond converter will be located within a short distance of St. John’s, close to the Nalcor headquarters with easy access by road. The Muskrat Falls converter station is within easy access of Happy Valley but if repairs to any converter fault have to be made by staff mobilized from St. John’s, then significantly longer repair times would apply to the Muskrat Falls converter. For this assessment, the two converter stations are assumed to be identical.

2.2 HVdc Line

Transmission line outage statistics for HVdc lines are not as readily available as those for ac lines. However, the available outage data of selected projects are presented in Table 2-4 from a compilation of CIGRE statistics produced during the 1990’s to provide an indication of the performance of HVdc lines to date. The reporting periods indicated below are the numbers of years for which data was available and do not necessarily represent the total numbers of years in service for each line.

Table 2-4: HVdc Transmission Line Outage Statistics

System	Length km	Reporting Period(yrs)	km-yrs	No. of Outages	f/100km /yr/pole	Avge Duration hrs
Pacific Intertie	847	8	6,776	51	0.376	1.48
Nelson River-1	960	11	10,560	45	0.213	0.53
Nelson River-2	960	11	10,560	41	0.194	0.52
Square Butte	749	9	6,741	5	0.037	1.69
CU	710	11	7,810	6	0.038	4.72
Itaipu-1	1200	6	7,200	21	0.146	2.06
Itaipu-2	1200	3	3,600	10	0.139	0.24
IPP	784	3	2,352	18	0.383	2.96
Average					0.191	1.78

Using the averages from Table 2-4, for a route length of 1,100 km, the expected reliability performance would be:

- 2.101 outages per pole per year,
- With an average repair time of 1.78 hours per outage

This translates into an unavailability and FOR of 0.0425% per pole.

The common-mode failure of both overhead poles must also be taken into account. It is assumed that this type of failure mode is at least one order of magnitude less likely than a single pole failure but with a longer average repair time and is therefore assumed to have a failure rate of 0.02 f/100km/yr with an average repair time of 24 hrs.

2.3 HVdc Submarine Cable

There is even less information related to the reliability of submarine cables than for overhead dc lines. Cable installations of all types are generally considered to be very reliable since they are installed in a protected environment. However, in the case of submarine cables, the repair time for a cable fault can be extremely long since it involves the mobilization of a repair ship and recovery of the cable, which may not be feasible during certain seasons of the year. The submarine cable crossing of the Straits of Belle Isle is being designed with a spare cable to cover the loss of one cable. Each cable will be rated to carry the rated power of one pole continuously with a 5-minute overload capability of 2xrated power.

A report by C-Core [4] examined the incidence of iceberg strikes on the submarine cables and concluded that the expected failure rates for such events would be:

- 0.004 failures/year for a single cable
- 0.002 failures/year for 2 cables
- 0.001 failures/year for 3 cables

Repair times for cables in the Strait of Belle Isle could be very long and a repair time of 6 months (4,380 hours) has been assumed. Other cable failures, due to internal failures and other external causes, such as fishing and shipping activities, are assumed to be no worse than 1 in 50 years or 0.02 failures/year. Since there is a spare cable that can be quickly switched to replace a failed cable, the probability of losing a single pole due to a cable fault is the sum of the independent failure of 2 cables plus the probability of an iceberg strike affecting 2 cables. The independent failure of 2 cables can therefore be calculated by:

$F_C = \lambda_{C1}.U_{C2} + \lambda_{C2}.U_{C1} + \lambda_{C1\text{-}2}$
$U_C = U_{C1}.U_{C2} + U_{C1\text{-}2}$

Where $\lambda_{C1\text{-}2}$, $U_{C1\text{-}2}$ represents the failure rate and downtime of 2 cables due to an iceberg strike.

This evaluates to a failure rate of 0.00022 f/yr for the independent failure of 2 cables and 0.002 f/yr due to iceberg strikes, for a total failure rate of 0.0022 f/yr with an average repair time of 4,163 hrs/outage and an average downtime of 9.24 hours/year. This corresponds to an FOR of 0.105%.

For the complete loss of the link, either all 3 cables would need to fail due to independent failure events or an iceberg strike would need to affect all 3 cables. The independent failure mode evaluates to a very small value (9.9E-6 f/yr) and is considered insignificant, leaving a failure of 3 cables due to an iceberg strike as the remaining cause with a failure rate of 0.001 f/yr with an average repair time of 4,380 hours/outage and an average downtime of 4.38 hours/year (An FOR of 0.05%).

2.4 Electrode Line

An electrode line will be provided at each converter station to connect to a remote ground electrode. These lines, under bi-pole mode, will carry only the unbalance current between the two poles of the dc line but will also be used at 150% rated pole current during mono-polar operations involving ground return. These lines are essentially medium voltage lines with 2 conductors for redundancy in case of conductor failure and will be continuously monitored for integrity. At the Muskrat Falls end, the electrode line is 400 km in length and at the Soldiers Pond end; it is only 10 km in length.

CEA statistics on transmission equipment performance for ac lines up to 110 kV indicate the average failure rate for such lines to be 5 outages/100km/year with an average repair time of 8.2 hours (downtime = 41 hours/100km/year, 0.47%). Using these values for the Muskrat Falls electrode line would result in 20 outages/year. This appears to be a high value for a line that is continuously monitored and that spends most of its time operating at a voltage well below its rated value. Accordingly, a failure rate equal to one-tenth of this value (i.e. 0.5 failures/100km/year) was assumed and the repair time was kept at 8.2 hours per outage.

For the common-mode failure of both circuits of the electrode line, a failure rate one order of magnitude lower was assumed (i.e. 0.05 failures/100km/year) and the repair time was taken to be the same as for the common-mode failure of both poles of the bipole (i.e. 24 hours). Even with both circuits of the electrode line out of service, it will still be possible to operate the link at rated power with the unbalance current being handled by the station ground or, at worst, running at reduced power in mono-polar mode using metallic return.

The electrode line at the Muskrat Falls end (400 km) will either be constructed on a separate wood-pole line or will be installed on the towers of the main dc line itself. It would be reasonable to expect the reliability of the electrode line to be improved if it is mounted on the main line since the majority of common-mode failure events associated with the main line would be the same common-mode failure events associated with the electrode line. Thus the common-mode failure of the two electrode line circuits is already included in the common-mode failure of the bipole. The impact of this is, however, relatively small.

Given the above considerations, it is considered that the reliability related to the complete loss of the Island Link will not be significantly influenced by the reliability of the electrode lines at either terminal.

3 COMPOSITE SYSTEM

The composite system reliability of the Island Link can be determined from a consideration of the reliability of the components of the system. The actual connection diagram of the Island Link together with the corresponding connection diagram for the individual components of the reliability is shown in Figure 3-1. The individual poles of the bipole (L1+C+L2) and the converters (CP) are shown as parallel elements since both must fail for the link to fail, while the common-mode failure of the bipole due to a converter fault (BPC or cable/line fault (BPL1, C3 and BPL2) are shown as series elements since any of these failures will result in failure of the link. In all the results tables that are presented in the following sections, the results have been rounded to the appropriate number of significant digits. However, in the actual calculations, the full number of decimal places was retained to ensure the overall arithmetic accuracy of the results.

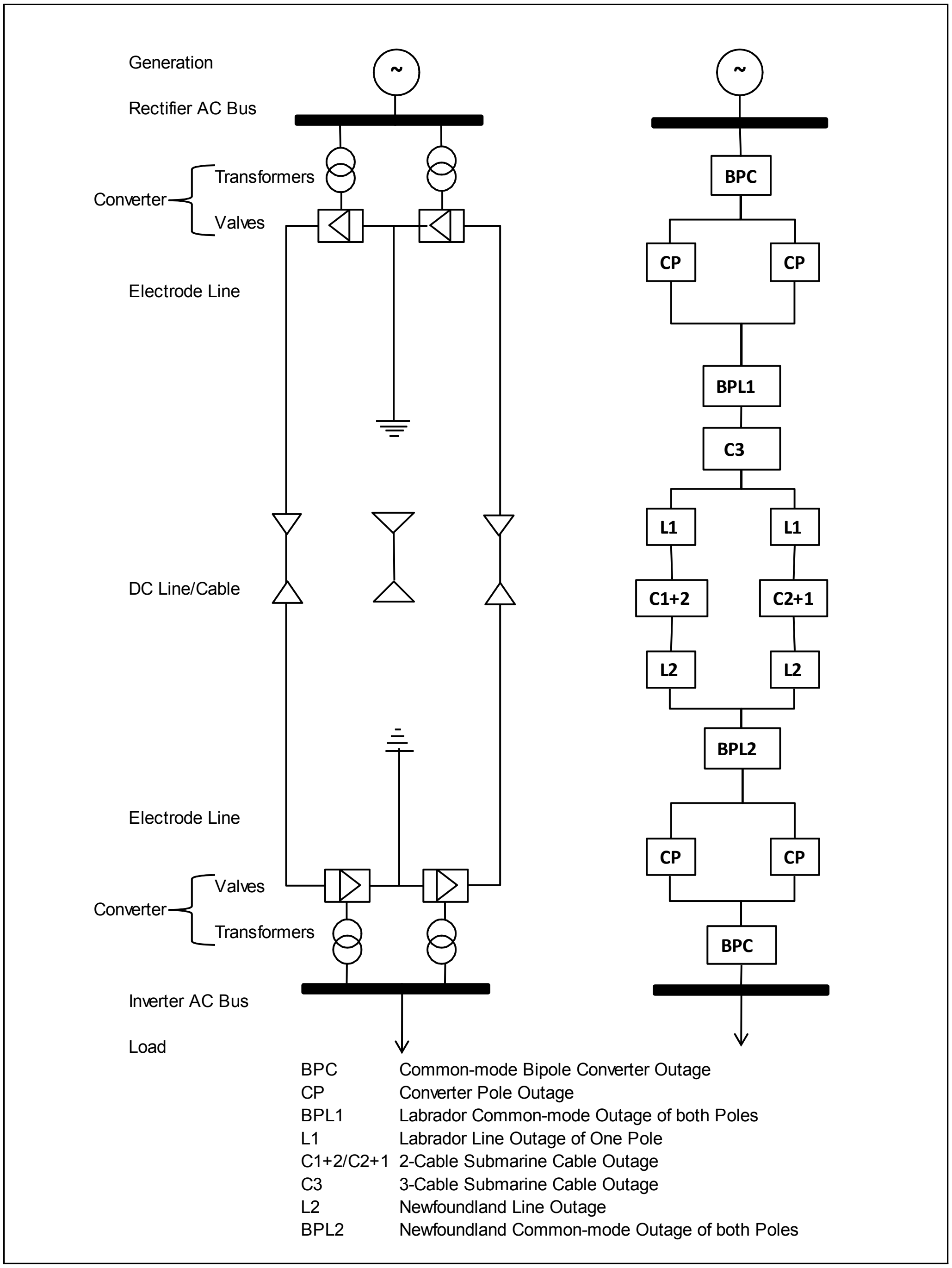
3.1 HVdc Overhead Line and Submarine Cable

First, it is necessary to determine the composite reliability indices associated with each parallel pole element (L1, C1+2, and L2 in series). Since the failure of any one of these elements will result in the failure of one pole, the failure rate and unavailability of each element can simply be added together as shown in Table 3-1. For each element, the downtime (or unavailability) is the product of the failure rate and the repair time ($U=\lambda.r$). Once the total failure rate and downtime have been determined, the repair time can be calculated as $r=U/\lambda$. For the submarine cable, the failure rate, repair time and downtime are those associated with the independent failure of 2 cables and an iceberg strike that impacts 2 cables.

Table 3-1: Reliability Performance of One Pole of the HVdc Line

Element	Failure Rate (f/yr)	Repair Time (hrs)	Downtime (hrs/yr)
L1-388 km	0.741	1.78	1.32
C-Submarine cable	0.0022	4,163	9.24
L2-680 km	1.3	1.78	2.31
Total	2.042	6.3	12.87

Figure 3-1: Island Link Reliability Connection Diagram



The reliability indices for the coincident, independent failure of two poles in parallel are given by:

$$\lambda_T = \frac{\lambda_1 \lambda_2 (\mathbf{r}_1 + \mathbf{r}_2)}{8760} \mathbf{f/yr}$$

$$\mathbf{r}_T = \frac{\mathbf{r}_1 \mathbf{r}_2}{\mathbf{r}_1 + \mathbf{r}_2} \mathbf{hrs}$$

$$\mathbf{U}_T = \lambda_T \mathbf{r}_T \mathbf{hrs/yr}$$

From the above composite reliability of each pole, the composite reliability of both poles in independent failure mode is:

$\lambda_T = (2.042)^2.(2x6.3)/8760 = 0.006$ f/yr
$r_T = (6.3)^2/(2x6.3) = 3.15$ hrs
$U_T = 0.006x3.15 = 0.019$ hrs/yr

In addition, for the complete failure of the link, the probability of an iceberg strike impacting all three submarine cables and the probability of a common mode outage of both overhead line sections must be added to the above independent, coincident failure of both poles.

3.2 Converters

Similarly, the coincident failure of both converters in independent mode can be calculated as:

$\lambda_T = (1.64)^2.(2x13.8)/8760 = 0.0084$ f/yr
$r_T = (13.8)^2/(2x13.8) = 6.9$ hrs
$U_T = 0.0086x7 = 0.06$ hrs/yr

3.3 Electrode Lines

As mentioned above, the link can still be operated at full power or reduced power even for the complete loss of the electrode line at either end of the link. As such, the reliability of the electrode line is considered to have no significant impact on the composite reliability of the link.

3.4 Complete System

For the failure of both lines/cables (P1+P2) or both converters (CP+CP), in series with the common-mode failure of both poles due to converter faults (BP) and main line faults (BPL1 and BPL2), the composite reliability of the Island Link is as shown below.

Table 3-2: Composite Island Link Bi-pole Reliability

Element	Failure Rate (f/yr)	Repair Time (hrs)	Downtime (hrs/yr)	% of Total
BP-Muskrat Falls	0.24	0.13	0.031	0.3
CP+CP-Muskrat Falls	0.0084	6.86	0.057	0.6
BPL1-388 km	0.074	24	1.776	18.6
P1 + P2	0.007	621.7	4.479	46.9
BPL2-680 km	0.13	24	3.12	32.7
CP+CP-Soldiers Pond	0.0084	6.86	0.057	0.6
BP-Soldiers Pond	0.24	0.13	0.031	0.3
Total	0.7078	13.49	9.551	100

The composite, forced unavailability and FOR is therefore 9.551 / 8760 x 100 = 0.109%.

It is clear from the above results that the major contributors to the unavailability of the Island Link are the common-mode failure of both poles of the overhead line (representing nearly 52% of the total unavailability) and the independent, coincident failure of both poles for the overhead and submarine cable sections (representing 47% of the total unavailability). Of all the values used for the component reliability, the reliability indices associated with common-mode bipole and submarine cable failures are probably the least certain given the relatively small database of operating experience. The parameter that has the most influence on the overall unavailability due to these failures is the repair time required to return a bipole or submarine cable to service after a common-mode failure. The value used in the above analysis was based on the limited operating experience available worldwide which includes bipolar lines of similar length to the Island Link in remote areas with difficult access.

The implied availability from this result is 99.89%. However, it should be borne in mind that this availability value includes periods of time when the full capacity of the link is unavailable. For a pole outage or converter outage or during scheduled maintenance, the link will be operated in mono-polar mode at a power level up to 150% of rated power per pole on a continuous basis.

3.5 Reduced Power Operation

The scheduled maintenance would typically be of the order of 3 days per pole per year, assuming that maintenance work would be carried out at both terminal stations and on each line (pole) at the same time. With respect to forced periods when the Island Link will not be available for full power transmission, it is necessary to consider only those single contingency events that will result in the loss of one pole of the Island Link. These comprise the loss of a converter at either end or the permanent outage of either pole of the main dc line. Using the values from Table 2-3 for the converters and Table 3-1 for the overhead line and submarine cable components, Table 3-3 shows the reliability indices associated with reduced power modes.

Table 3-3: Reduced Power Capability Modes (Mono-polar)

Element	Failure Rate(f/yr)	Repair Time(hrs)	Downtime(hrs/yr)
Scheduled Maintenance	2.0	72	144
Converter-Muskrat Falls	1.64	13.8	22.42
Pole 1	2.04	6.3	12.87
Pole 2	2.04	6.3	12.87
Converter-Soldiers Pond	1.64	13.8	22.42
Total	9.36		214.6

The composite unavailability and FOR is therefore 214.6 / 8760 x 100 = 2.45%.

Thus, the actual availability of the Island Link at full power capacity is 100-0.109-2.45 = 97.44%.

If the use of the station ground for mono-polar operation is not allowed in the event of the loss of the electrode line, the above values will be increased slightly due to the failure of both conductors of the electrode line. Only the loss of the Muskrat Falls electrode line will be significant since the length of the Soldiers Pond electrode line is relatively short. The coincident failure of both conductors of the Muskrat Falls electrode line was estimated at 0.2 failures/year with an average repair time of

24 hours and a downtime of 4.8 hours/year. If these values are added to those shown in Table 3-3 above, the resulting overall FOR increases from 2.45% to 2,51%.

The impact of the repair time for the common-mode failure of both circuits of either the Muskrat Falls electrode line or the main dc line is dominant to the point where the total forced unavailability can be approximated as being proportional to the repair time for such an event. Varying the fault repair time over the range of 3 hours to 10 days, with all other component reliability indices being held constant, the total forced unavailability in % is approximately 2.5/1000 x bi-pole repair time in hours. If a specific reliability performance is required (e.g. total forced unavailability ≤ 0.5%), then the repair time for a bi-pole line fault must be kept within 192 hours (8 days). This strong correlation between the unavailability of the link and the repair time associated with common-mode failures of both poles of the main dc line allows the desired reliability to be associated with target repair times. The unavailability of the link at full power, due to single pole forced outages or maintenance, is shared equally by the repair time for one pole and the time required for pole maintenance.

4 CONCLUSIONS & RECOMMENDATIONS

<u>Objective 1:</u> To develop R&A performance indices for converter stations

Using historical information compiled by CIGRE from HVdc installations throughout the world over the period 1988-2008, failure rates and repair times were estimated for the converter stations at each end of the Island Link.

Table 4-1: Converter Reliability (Average 2007-2008)

Outage	FOR (%)	FU(hrs/yr)	F/yr	Repair Time (hrs)
Pole	0.265	24	1.64	13.8
Bipole	0.00025	0.02	0.24	0.13

<u>Objective 2:</u> To develop R&A performance indices for the HVdc transmission line from Muskrat Falls to Soldiers Pond

- To assess the improvements that could be made in the above indices considering design aspects such as the provision of spare equipment, over-rated equipment, etc.,
- To assess the composite R&A performance indices of the complete HVdc Island Link from Muskrat Falls to Soldiers Pond.

Table 4-2: Reliability Performance of the HVdc Line

Element	Failure Rate (f/yr)	Repair Time (hrs)	Downtime (hrs/yr)
L1-388 km	0.741	1.78	1.32
C-Submarine cable	0.0022	4,163	9.24
L2-680 km	1.3	1.78	2.31
Total	2.042	6.3	12.87

The associated FOR is 0.147%.

Table 4-3: Composite Island Link Reliability

Element	Failure Rate (f/yr)	Repair Time (hrs)	Downtime (hrs/yr)	Downtime % of Total
BP-Muskrat Falls	0.24	0.13	0.031	0.3
CP+CP-Muskrat Falls	0.0084	6.86	0.057	0.6
BPL1-388 km	0.074	24	1.776	18.6
P1 + P2	0.007	621.7	4.479	46.9
BPL2-680 km	0.13	24	3.12	32.7
CP+CP-Soldiers Pond	0.0084	6.86	0.057	0.6
BP-Soldiers Pond	0.24	0.13	0.031	0.3
Total	0.7078	13.49	9.551	100

The associated FOR is 0.109%. The availability is therefore 99.89%.

Table 4-4: Reduced Power Capability Modes

Element	Failure Rate(f/yr)	Repair Time(hrs)	Downtime(hrs/yr)
Scheduled Maintenance	2.0	72	144
Converter-Muskrat Falls	1.64	13.8	22.42
Pole 1	2.04	6.3	12.87
Pole 2	2.04	6.3	12.87
Converter-Soldiers Pond	1.64	13.8	22.42
Total	9.36		214.6

The associated unavailability is 0.81% due to the forced outage of one pole and 1.64% due to the scheduled maintenance outage of a pole. If the station ground cannot be used for mono-polar operation when the Muskrat Falls electrode line is also unavailable, the total FOR will increase from 2.46% to 2.51%.

4.1 Conclusions

The provision of a spare transformer of each type and a spare smoothing reactor at each converter station will significantly improve the availability of the converters. This has become common practice in recent HVdc schemes.

Using representative reliability data from existing HVdc installations throughout the world, the overall forced unavailability of the complete Island Link is predicted to be approximately 0.1%. The forced unavailability of the full power capability of the Island Link is predicted to be less than 2.5%, with the scheduled unavailability for maintenance being 1.64%. However, both of the values for forced unavailability are very dependent on the average repair time that can be achieved for pole outages and common-mode failures of both poles of the dc line.

It has been shown that a linear relationship exists between these repair times and the unavailability of the Island Link. Once a target reliability has been decided on, the maximum repair time can be determined. The overall unavailability of the complete link is not sensitive to the repair time for the submarine cables. This is due to the provision of a spare submarine cable across the Strait of Belle Isle and the subsequent very low failure rates for 2 or 3 cables. An increase in the repair time for a common-mode failure of both overhead line sections of the dc line (due to a tower failure, for example) from 24 hours to 2 weeks (336 hours) resulted in an increase in the total unavailability from 0.108% to 0.835%.

Based on the historical data available, the repair time for single pole outages on the overhead line sections was estimated at 1.78 hours/outage, while the repair time for common-mode failure of both poles was assumed as 24 hours. If both these repair times are varied then the overall unavailability will change. The following values of overall FOR were calculated for a range of overhead dc line section repair times (these repair times were used for both independent, coincident failures of both poles and for the common-mode failure of both poles).

Table 4-5: Variation in Overall FOR with DC Overhead Line Repair Time

Repair Time(hrs)	FOR(%)
24 (1 day)	0.112
48 (2 days)	0.179
72 (3 days)	0.251
96 (4 days)	0.33
120 (5 days)	0.416
144 (6 days)	0.507
168 (1 week)	0.605
336 (2 weeks)	1.463

The relationship is not linear, as may be expected, but does show the dependence of the unavailability on the repair time associated with overhead dc line section faults.

The total unavailability of full power due to a pole outage is determined to a large extent by the scheduled maintenance outage of each pole.

4.2 Recommendations

At each converter station, a spare converter transformer of each type (single phase) and a spare smoothing reactor should be provided. This will significantly improve the availability of the converters.

Other critical components and those items with long lead times should also be considered as items that should be provided with on-site spares. These items are normally determined by the converter supplier in order to meet the specified target reliability and availability values in the converter specification.

5 REFERENCES

1) Nalcor Energy-Lower Churchill Project, :Basis of Design, Document LCP-PT-ED-0000-EN-RP-0001-O1.
2) A Survey of the Reliability of HVDC Systems throughout the World during 2007 – 2008, M.G. Bennett, N.S.Dhaliwal, A. Leirbukt
   CIGRE 2010 Technical Session, Paris, Paper: B4_209_2010
3) Newfoundland & Labrador HVDC Project, HVDC Link Reliability Studies, Power Technologies Inc., Schenectady, NY, Report R-64-81, 11 October, 1981.
4) Iceberg Risk to Subsea Cables in the Strait of Belle Isle, C-Core Report ILK-CC-CD-8110-EN-RP-0001-01, June 2011.

APPENDIX A

RELIABILITY FORMULAE

Individual Components

The reliability of any individual component of a system can be expressed in terms of its failure rate (λ), repair time (r), availability (A) and unavailability or downtime (U). These indices are linked in the following relationships:

U = λ . r

A = (1-U)

The failure rate is normally expressed in the number of failures/year, the repair time is normally expressed in hours/repair, availability and downtime are normally expressed in hours/year or in per unit/year where the repair time is divided by 8760 hours/year.

Thus a component with a failure rate of 2 failures/year and a repair time of 24 hours/repair will have a downtime of 2 x 24 = 48 hours/year or 48/8760 = 0.0055 p.u./year (sometimes expressed as 0.55%).

Furthermore, the forced outage rate (FOR) can be calculated as:

$\mathbf{FOR} = \frac{\mathbf{U}}{1+\mathbf{U}}$, which can be approximated as FOR = U where U is small in relation to unity.

Components in Series

In a system where the failure of any single component will result in failure of the system, the components are said to be connected in series, using the analogy of an electrical circuit. In such a system, the total system failure rate is simply the sum of the failure rates of the individual components. Similarly, the downtime of the system is the sum of the downtimes of the components.

For example if a system comprises two components, one with a failure rate of 2 failures/year and a downtime of 24 hours/year (repair time = 24/2 = 12 hours/failure); the other with a failure rate of 3 failures/year and a downtime of 12 hours (repair time = 12/3 = 4 hours/failure), the system failure rate will be 5 failures/year with a total downtime of 36 hours/year (repair time = 36/5 = 7.2 hours/failure).

Components in Parallel

In a system where multiple components must fail to result in failure of the system, the components are said to be connected in parallel, again using the analogy of an electrical circuit. For a two component system, two possible failure modes can be envisaged: the failure of component 2 while component 1 is in a failed state and the failure of component 1 while component 2 is in a failed state. This is expressed mathematically as follows:

$$\lambda_T = \lambda_2 . \mathbf{U}_1 + \lambda_1 . \mathbf{U}_2 = \lambda_2 . (\lambda_1 . \frac{\mathbf{r}_1}{8760}) + \lambda_1 . (\lambda_2 . \frac{\mathbf{r}_2}{8760}) = \frac{\lambda_1 . \lambda_2 . (\mathbf{r}_1 + \mathbf{r}_2)}{8760} \ \textbf{failures / year}$$

The total downtime is simply the product of the individual downtimes.

$U_T = U_1 . U_2$

From which the average repair time can be calculated as:

$$\mathbf{U}_T = \lambda_1 . \mathbf{r}_1 . \lambda_2 . \mathbf{r}_2$$

$$\mathbf{r}_T = \frac{\mathbf{U}_T}{\lambda_T} = \frac{\lambda_1 . \mathbf{r}_1 . \lambda_2 . \mathbf{r}_2}{\lambda_1 . \lambda_2 . (\mathbf{r}_1 + \mathbf{r}_2)} = \frac{\mathbf{r}_1 . \mathbf{r}_2}{\mathbf{r}_1 + \mathbf{r}_2} \ \textbf{hours / failure}$$

Using the same example used for components in series:

$$\lambda_T = \lambda_2 . \mathbf{U}_1 + \lambda_1 . \mathbf{U}_2 = 3\,\mathbf{x}\,24/8760 + 2\,\mathbf{x}\,12/8760 = 0.011 \ \textbf{failures / year}$$

$$\mathbf{U}_T = \mathbf{U}_1 . \mathbf{U}_2 = 24\,\mathbf{x}\,12/8760 = 0.033 \ \textbf{hours / year}$$

$$\mathbf{r}_T = \frac{4\,\mathbf{x}\,12}{4+12} = 3 \ \textbf{hours / failure} \ \ \textbf{or} \ \ \mathbf{r}_T = \frac{\mathbf{U}_T}{\lambda_T} = \frac{0.033}{0.011} = 3\,\textbf{hours / failure}$$

APPENDIX B

CIGRE HISTORICAL DATA 1988-2008

SNC·LAVALIN	RELIABILITY & AVAILABILITY ASSESSMENT OF THE HVDC ISLAND LINK	Revision		
	Nalcor Doc. No.: ILK-SN-CD-8000-EL-SY-0004-01	B1	Date	Page
	SLI Doc.: No. 505573-480A-47ER-0017	00	10-Apr-2012	B-1

CIGRE Historical Data 1988-2008 per Terminal

2 Terminal Systems - 1 Converter per Pole

Name	2007				2008				Average 1988-2008				
	Pole		Bipole		Pole		Bipole		Years	Pole		Bipole	
	fp	dp	fb	db	fp	dp	fb	db		fp	dp	fb	db
Skagerrak 1 & 2	1.25	3.1	0	0	2	3.8	0.5	1	20	1.54	17.1	0.13	1.03
Square Butte	1	4.1	1.5	0.3	5.25	0.8	0	0	18	2.85	6.2	0.42	2.27
CU	0.5	23.8	0	0	1.25	58.5	0	0	20	1.71	4.6	0.28	1.66
Gotland 2&3	0.25	0.8	0	0	0.5	46.6	0	0	20	0.38	35.8	0.2	1.49
Fennoskan	2	14.2			1.5	46.4			19	2.26	10.1		
SACOI	3.33	1.7			1.67	2.5			16	4.9	2.6		
New Zealand 2	2.5	4.3			0.5	0.7			17	1.65	2.7		
Kontek	0.5	2.7			1	32			7	0.86	15.7		
SwePol	0.5	2.4			2	1.7			8	3.56	21		
Kii Channel	0	0		0	0	0	0	0	8	0.16	99.6	0	0
Grita	4	42.2			4.5	9.3			5	2.7	17.1		
Average	1.44	9.03	0.38	0.06	1.83	18.39	0.10	0.20	158	2.05	21.14	0.21	1.29

Downtime (hrs/yr)	13.0		0.02		34		0.02			43.4		0.27	
FOR/U(hrs/yr)	0.15%		0.0003%		0.38%		0.0002%			0.49%		0.003%	

TECHNICAL NOTE (FINAL)
APPENDIX C

Appendix C

Summary of CIGRE HVdc Reliability Data
System Energy Availability (2015-2016)[14]

[14] Developed from CIGRE Document B4-137 Table I – System Energy Availability, Energy Utilization and Converter Station Energy Unavailability

newfoundland labrador hydro
a nalcor energy company

TECHNICAL NOTE (FINAL)
APPENDIX C

Table C-1: System Energy Availability, Energy Utilization and Converter Station Energy Unavailability[15]

System	Year Commissioned	Maximum Continuous Capacity (MW)	Energy Availability (%)		Energy Utilization (%)[1]		Forced Energy Unavailability (%)[2]		Scheduled Energy Unavailability (%)[2]	
			2015	2016	2015	2016	2015	2016	2015	2016
Skagerrak 1 & 2	1976/77	550	-	96.5	-	35.9	-	0.52	-	2.94
Skagerrak 3 & 4 (3)	1993/15	1215	-	97.2	-	64.3	-	0.27	-	2.57
Square Butte	1977	550	95.7	68.4	62.8	48.4	2.45	15.99	1.86	13.46
Nelson River BP1	1973/04	1855	89.8	93.4	66.2	67.1	1.92	0.84	8.27	5.73
Nelson River BP2	1978/83	2000	98.2	96.7	78.1	74.2	0.26	0.10	1.52	3.16
Hokkaido-Honshu	1979/93	600	94.8	96.8	16.9	20.3	0.00	0.00	5.21	3.17
CU	1979	1138	97.5	94.8	82.3	75.4	0.02	0.01	2.51	5.22
Gotland 2 & 3	1983/87	320	99.4	99.6	18.1	20.7	0.02	0.04	0.60	0.33
Itaipu BP1	1984/85	3150	91.6	97.4	69.2	77.7	6.01	0.01	2.39	2.55
Itaipu BP2	1987	3150	96.1	95.0	69.2	77.7	0.00	0.03	3.90	4.97
Highgate	1985	225	97.5	97.5	85.0	91.3	0.04	0.00	2.42	2.46
Virginia Smith	1988	200	74.5	92.8	6.1	4.4	12.85	1.27	12.65	5.96
Konti Skan 2	1988	300	-	95.2	-	60.2	-	0.32	-	4.48
Vindhyachal	1989	500	83.7	76.5	41.5	50.3	15.50	22.87	0.82	0.68
McNeil	1989	150	95.3	95.6	13.7	16.8	1.32	0.54	3.40	3.85
Fenno-Skan 1	1990	400	97.4	98.3	95.3	92.6	0.68	0.26	1.93	1.42
Fenno-Skan 2	2011	830	97.5	98.6	75.5	70.4	0.00	0.29	2.45	1.05
Rihand-Dadri	1991	1650	97.1	96.0	80.9	69.8	0.52	0.63	2.35	3.30
SACOI (4)	1992	300/300/50	91.3	89.0	45.4	60.0	0.85	0.82	7.68	8.55
New Zealand Pole 2 (5)	1992	500	98.8	99.2	33.1	43.9	0.09	0.01	1.11	0.80
New Zealand Pole 3 (5)	2013	700	98.9	99.0	23.9	32.7	0.09	0.00	1.01	0.97
Sakuma	1965/93	300	97.6	100.0	0.0	0.0	0.36	0.00	2.03	0.00
Kontek	1998	600	-	89.8	-	66.8	-	0.02	-	10.20
Chandrapur	1998	1000	98.3	97.2	95.8	83.2	0.87	2.49	0.87	0.27
Minami-Fukumitsu	1999	300	95.0	89.3	3.8	4.3	0.00	1.73	5.00	8.97
SwePol	2000	600	95.5	95.5	67.2	55.8	0.63	0.12	3.90	4.41
Vizag I East-South	2000	500	99.8	99.3	62.2	52.7	0.01	0.68	0.17	0.03
Vizag II East-South	2005	500	99.9	100.0	68.7	55.2	0.03	0.00	0.11	0.03
Kii Channel	2000	1400	97.2	97.8	78.8	74.1	0.00	0.00	2.84	2.18
Tiang-Guang	2001	1800	98.4	-	55.7	-	0.02	-	1.62	-
Malaysia-Thailand	2001	300	91.6	93.5	9.7	10.2	5.01	3.29	3.35	3.10
Grita	2001	500	72.2	71.2	51.7	53.1	0.33	1.68	8.15	7.23
Talcher-Kolar	2003	2000	99.3	98.8	90.9	90.7	0.04	0.24	0.69	0.97
Sasaram	2003	500	94.4	95.5	55.9	55.9	5.62	2.33	0.00	2.17
Gui-Guang Bipole 1	2004	3000	99.8	-	67.7	-	0.01	-	0.20	-
Gui-Guang Bipole 2	2010	3000	99.2	-	60.0	-	0.00	-	0.83	-
Higashi-Shimizu	2006	300	94.5	96.6	50.8	52.5	0.00	0.00	5.50	3.44
EstLink 1 (6)	2007	350	98.2	98.6	29.3	22.3	0.41	0.12	1.35	1.15
EstLink 2	2013	450	91.1	95.7	73.1	53.8	5.04	0.02	0.85	4.26
NorNed	2008	700	98.7	97.8	94.3	72.7	0.04	0.08	1.24	2.11
Al Fadhili	2009	1800	98.4	98.4	6.2	8.9	0.74	0.67	0.87	0.90
Cahora Bassa	1977/2009	1920	-	76.5	-	61.5	-	9.99	-	13.47
SAPEI	2009	1000	94.0	96.0	31.8	31.3	0.12	0.62	5.87	3.37
Caprivi (6)	2009	300	-	98.3	-	42.8	-	0.11	-	1.55
Storebaelt	2010	600	-	98.7	-	78.0	-	0.05	-	1.23
Ballia-Bhiwadi	2010	2500	98.8	96.3	13.0	13.6	0.05	2.64	1.12	1.05
Yun Guang	2010	5000	94.0	-	64.8	-	0.02	-	5.96	-
WATL	2016	1000	-	81.3	-	25.7	-	14.77	-	3.93
EATL	2016	1000	-	62.5	-	14.3	-	30.85	-	6.61
NER-Agra	2016	2000	-	82.3	-	33.0	-	9.36	-	8.00
		Average	**95.0**	**93.1**	**52.4**	**49.3**	**1.55**	**2.75**	**2.87**	**3.66**

Notes:
(1) Based on maximum continuous capacity
(2) Converter station outages only
(3) One pole VSC
(4) Three terminal monopole system
(5) Bipole reporting as two poles
(6) VSC system

[15] Developed from CIGRE Document B4-137 Table I – System Energy Availability, Energy Utilization and Converter Station Energy Unavailability

Reliability and Resource Adequacy Study

Volume II: Near-Term Reliability Report

November 16, 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1 Introduction

Newfoundland and Labrador Hydro ("Hydro") recognizes that supply adequacy in advance of the availability of full production from the Muskrat Falls Generating Facility is top of mind for its stakeholders. The enclosed assessment of near-term resource adequacy takes an in-depth view of system risks and mitigating measures to ensure Hydro can reliably meet the needs of its customers through the full system transition.

This Volume of the Study discusses the near-term resource adequacy and reliability of the Newfoundland and Labrador Interconnected System ("NLIS") for a five-year period, 2019 – 2023, and provides the results of the probabilistic resource adequacy assessment for the NLIS through the near-term. The reliability indices in this near-term report include both annual and monthly Loss of Load Hours ("LOLH"), Expected Unserved Energy ("EUE"), and Normalized EUE[1] for a five-year period. The analysis considers the different types of generating units (i.e., thermal, hydro, and wind) in Hydro's fleet, firm capacity contractual sales, transmission constraints, peak load, load variations, load forecast uncertainty, and demand side management programs. Similar to previous analyses, a range of projected availabilities was considered for the Holyrood Thermal Generating Station ("Holyrood).

For the analysis and model development, Hydro utilized the North American Electric Reliability Corporation ("NERC") "Probabilistic Assessment Technical Guideline Document" and the NERC "Reliability Assessment Guidebook" to ensure alignment with accepted industry practice.

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

The analysis was conducted consistent with the format proposed in the NERC "Probabilistic Assessment Technical Guideline Document" that provides modelling "*practices, requirements and recommendations needed to perform high-quality probabilistic resource adequacy assessments.*"[2] As such, this edition of the near-term report is a hybrid of the methodology used in prior near-term generation filings, paired with the assessment guidelines as defined by NERC.

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

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

Given the current evolving nature of the NLIS, an analysis was conducted for each of the next five years (2019 to 2023) to provide the Commissioners of the Board of Public Utilities ("Board") with insight into the evolution of system reliability as the Lower Churchill Project assets are integrated into the NLIS. Going forward, Hydro intends to continue providing this analysis, with a migration to the methodology used by other jurisdictions to support NERC reliability assessments (i.e., detailed reporting view for years two and four). Hydro proposes this report,

[2] "Probabilistic Assessment Technical Guideline Document," NERC, August 2016.
<https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf>

together with Volume III: Long-Term Resource Plan, be filed with the Board annually in November.

While results are presented in a manner different than those previously provided to the Board as part of the Near-Term Generation Adequacy assessments, the analysis itself is improved over that previously conducted. The analysis now uses Hydro's fully implemented reliability model, which is rooted in detailed hourly chronological simulation. Further, inputs are modelled stochastically, and improved capabilities, such as inclusion of the load forecast uncertainty parameter, have been implemented in the analysis. The outcome is a more robust analysis, which allows for better risk-informed decision making.

2 Modelling Approach

Detailed modelling of the near-term supply period was undertaken using the reliability model developed in 2018.[3] It is noted that transmission system adequacy is assessed separately in accordance with Transmission Planning Criteria; these are posted publically on the Newfoundland and Labrador System Operator ("NLSO") Open Access Same-Time Information System ("OASIS") website. [4]

3 Asset Reliability

On a quarterly basis, Hydro reports to the Board on the rolling 12-month performance of its units,[5] including actual forced outage rates and their relation to: (i) past historical rates, and (ii) the assumptions used in assessment of resource adequacy. The most recent report was submitted on October 31, 2018, for the quarter ending September 30, 2018. These reports

[3] For a detailed description of the modelling parameters and assumptions, refer to Volume I, Section 4.2 of this Study.
[4] NLSO Standard Transmission Planning Criteria Doc # TP-S-007," Newfoundland and Labrador Hydro, May 11, 2018 <http://www.oasis.oati.com/woa/docs/NLSO/NLSOdocs/TP-S-007_Transmission_Planning_Criteria_UPDATED_05112018.pdf>
[5] Quarterly Report on Performance of Generating Units.

detail unit reliability issues experienced in the previous 12-month period and compare performance for the same period year-over-year.

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

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

3.1 Factors Affecting Recent Historical Generating Asset Reliability

Hydro has reviewed the factors affecting generating unit reliability since its last filing of the "Near-Term Generation Adequacy Report" in May 2018. Updates on these items, as well as any additional items which may impact asset performance in the near-term, are provided in this Volume of the Study. The intention is to ensure issues affecting reliability have been appropriately addressed as issues that are recurring in nature, if not managed properly, can have a significant impact on unit reliability. The information included in Sections 3.1.1 through 3.1.3 of this report provides an overview of the repeat or broader issues. Isolated equipment issues (i.e., those that occur once on a particular unit) are also investigated, with the root cause identified and corrected. These types of issues are considered when selecting appropriate Deration Adjusted Forced Outage Rates ("DAFOR") and Derated Adjusted Utilization Forced Outage Probabilities ("DAUFOP")/Utilization Forced Outage Probabilities ("UFOP").

Impacts to asset performance are considered in the selection of appropriate DAFOR and DAUFOP/UFOP.

The following sections provide a description of issues, both asset- and condition-based, that have previously affected generating unit reliability, as well as the current status of those issues and the actions taken to mitigate against future reliability impacts. The scope is not limited to Hydro's assets (e.g., penstock, boiler tubes), but also considers environmental challenges facing Hydro's operations (e.g., lower than average inflows).

As part of this exercise, Hydro has identified the following items, grouped by facility type:

- **Hydraulic Facilities**: Continued monitoring (Bay d'Espoir penstocks); ongoing (Hinds Lake rotor resistance, Granite Canal control system); and resolved (Upper Salmon rotor rim key cracking, Hinds Lake bearing coolers, Cat Arm spherical valve controls);
- **Thermal Facilities**: Ongoing (unit boiler tubes, variable frequency drives, air flow limitations due to normal boiler fouling during operating season, and Unit 1 and Unit 2 hydraulic fluid condition); and
- **Gas Turbines**: Resolved (End A unavailability at Stephenville, combustion can failures at Hardwoods, and bellows cracking at Hardwoods).

Risks not specifically noted above are embedded in the DAFOR and DAUFOP assumptions selected for each asset.

3.1.1 Hydraulic

3.1.1.1 *Bay d'Espoir Penstocks*

Hydro's May 2018 "Near-Term Generation Adequacy Report" noted that the condition assessment of Bay d'Espoir Penstock 3 confirmed the presence of cracks. Necessary refurbishments were completed and the penstock was returned to service in spring 2018. Additionally, following major refurbishments in maintenance season 2017, inspections and condition assessments were completed on Penstock 1 in the summer of 2018 and on Penstock 2 in the fall of 2018. The previous refurbishments performed well and were deemed successful.

The report discussing the three penstock condition assessments will be filed with the Board as outlined in P.U. 23(2018). It is currently expected this report will be filed in the first quarter of 2019.

Hydro has revised its preventive maintenance program for penstock inspections to reduce the likelihood of future events.

Hydro has revised its preventive maintenance program for penstock inspections to reduce the likelihood of future events. The inspection for steel penstocks that includes non-destructive testing on the welds has been established and it includes the use of external specialists.[6] Additionally, Hydro has developed a Penstock Inspection Plan which outlines the inspection and refurbishment schedule for all penstocks. As part of the Penstock Inspection Plan, Hydro completed inspections in Cat Arm and Upper Salmon in 2018, which revealed no material issues. Additionally, penstock inspections are planned for Granite Canal in 2019 and Hinds Lake in 2020. The long-term Bay d'Espoir penstock inspection, maintenance, and investment plan will be informed by the Condition Assessment report currently underway.

3.1.1.2 *Hinds Lake Rotor Resistance*

As part of Hydro's preventive maintenance program for hydraulic generators, rotor resistance readings are measured and recorded on an annual basis.[7] For the unit in Hinds Lake, a critical resistance value of 0.14 Mohms was established by the Original Equipment Manufacturer ("OEM"), Mitsubishi Hitachi Power Systems Canada Ltd. While readings have trended down over the past several years, they have not yet reached the critical level. Hydro completed maintenance in the fall of 2018 to improve readings and is confident the rotor will remain in

[6] Future inspection frequency and scope may evolve depending of the recommendations stemming from the Level 2 condition assessments completed on Bay d'Espoir penstocks in 2018, as well as the findings from the root cause analysis of the Penstock 1 failure in 2017.

[7] The Original Equipment Manufacturer ("OEM") provides a critical threshold value for this reading. It is industry practice for the rotor to be refurbished before reaching this value.

reliable service until 2019 when the rotor is scheduled for a refurbishment, pending Board approval.[8]

Hydro installed a new relay during the fall 2018 maintenance outage which monitors the rotor resistance in real time while the unit is online generating, allowing Hydro to assess and monitor rotor condition on an ongoing basis and trend the resistance. At present, the value is above critical at 0.53 Mohms.[9] The resistance readings are currently holding and not deteriorating. Should the readings deteriorate to a point of concern, unit protection will remove the unit from service, allowing Hydro time to inspect and perform maintenance.

The project proposal submitted as part of Hydro's "2019 Capital Budget Application" involved the refurbishment of the Hinds Lake rotor, including planning and engineering in 2019 and execution of the refurbishment in 2020. However, based on current rotor resistance readings and anticipated remaining useful life, it is Hydro's intention to complete execution of the refurbishment in 2019, pending Board approval.

3.1.1.3 *Granite Canal Control System*

The generating unit and the control system at Granite Canal have been in operation since the plant's commissioning in 2003. Hydro has experienced control system malfunctions when remotely starting and/or stopping the unit. This has resulted in four forced outages since Hydro's May 2018 "Near-Term Generation Adequacy Report." Hydro engaged the control system OEM, ABB, to investigate solutions to improve reliability of this system prior to the 2018-

Hydro engaged the control system OEM to investigate solutions to improve reliability of the system prior to the winter operating season.

[8] Submitted as part of Hydro's "2019 Capital Budget Application."
[9] As of November 9, 2018.

2019 winter operating season. Through the collaborative work between Hydro and ABB, a short-term solution was implemented on October 13, 2018. At this time, Hydro is assessing the effectiveness of the proposed solution through the monitoring of unit operation. Following the conclusion of the ongoing investigation, any findings will be implemented, or, if capital expenditures are required, Hydro will propose a capital project as per the Capital Budget Guidelines.

3.1.1.4 *Upper Salmon Rotor Key Cracking*

As per consultation with the OEM, Hydro has continued to schedule and conduct regular inspections of rotor rim key welds at Upper Salmon. Since the May 2018 "Near-Term Generation Adequacy Report" Hydro inspected the Upper Salmon unit on multiple occasions. In all but one inspection, cracked welds were identified and repaired immediately.

Hydro has continued to schedule and conduct regular inspections of rotor rim key welds.

Hydro has since replaced the rotor rims keys during the unit annual maintenance outage. Hydro will continue to monitor this situation throughout the 2018-2019 winter season and validate that the new rotor rim keys are operating as expected.

3.1.1.5 *Hinds Lake Bearing Coolers*

The replacement of the six lower generator bearing coolers on the Hinds Lake generating unit coolers was completed in July 2018. Hydro now considers this issue to be resolved.

3.1.1.6 *Cat Arm Spherical Valve Controls*

As part of the 2018 Capital Refurbishment Plan, the spherical valve controls on both units in Cat Arm were upgraded during the planned maintenance outage. The new control system was successfully commissioned and Hydro now considers this issue to be resolved.

3.1.2 Thermal

3.1.2.1 *Unit Boiler Tubes*

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

> **Hydro inspects boiler tubes on an annual basis to verify the condition and to identify trends.**

Due to the failure of some tubes and thinning walls in others, Hydro experienced both unit outages and unit deratings in winter 2015-2016. At the time of the failures, the affected tube sections were known to have deteriorated significantly but had not been replaced because it was thought that the end of life of the tubes would coincide with the end of operation for the boilers. These tubes, which were in the reheater sections of Unit 1 and Unit 2, were replaced during annual planned unit outages in 2016, prior to the 2016-2017 winter season. There have been no boiler tube related outages or deratings in the reheater sections since these replacements were completed. This specific issue is considered to be resolved.

In May 2018 there was a boiler tube failure in the lower waterwall section of Unit 2 and the failed tube was replaced. A laboratory analysis of the failure determined that the failure was due to a crack that had developed at an original butt weld between two pieces of tube, made during the time of boiler construction. Analysis showed that this weld was of poor quality when installed. The weld on the adjacent tube, that did not fail, was also removed from the boiler and examined by the lab. The quality of this weld was much better than the one that failed with no cracking observed. There is no record of any previous boiler tube failure in this area at Holyrood.

Hydro conducts an annual tube inspection program to mitigate the possibility of tube failures and is confident that boiler tube sections, as a whole, are in good condition. Hydro continues to recognize that random tube failures pose a risk, particularly given the age of the Holyrood boilers. Hydro maintains a thorough selection of spare tube material and has an established contract with B&W for the provision of emergency repairs in the event of tube failures. As such, should a tube failure occur, return to service time is accounted for in the projected DAFOR targets.

3.1.2.2 *Variable Frequency Drives*

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

Previous to winter 2016-2017 there had been operational issues with the VFDs resulting in unit trips and reduced unit output. Throughout 2016, Hydro worked closely with Siemens, the OEM, to resolve the issues and improve the reliability of these drives. As a result, multiple aspects of the VFDs were modified and additional actions were taken to improve reliability. Subsequently, the VFDs operated reliably throughout the 2016-2017 operating season.

Hydro continued to work with Siemens in 2017 and completed preventive maintenance on all the drives during the annual outages. Hydro also implemented a spare part cycling strategy to reduce the likelihood of shelf-life failures by rotating spare parts through the operating equipment. Despite this work, there were reliability issues with the drives during the 2017-2018 operating season.[10]

[10] On February 17, 2018, there was a failure of the Unit 3 east cabinet cooling fan that caused a forced derating to 50 MW for approximately one hour while the fan was replaced. On March 19, 2018, the west VFD on Unit 1 tripped due to a failure of a power cell. On March 26, 2018 the east VFD on Unit 1 tripped due to a failure of a power cell.

Hydro completed preventive maintenance work on the drives in 2018 and continues to ensure readiness to respond, with required spares available. For the 2018-2019 operating season, Hydro has implemented operating strategies to reduce the likelihood of VFD failures, such as pre-energizing VFD equipment prior to unit start-ups and operating the drives in VFD mode. A contingency plan has been prepared that will enable bypassing of the VFD units at short notice should issues develop that impact reliability and customer service. This would be a permanent bypass requiring electrical connections and logic changes in the distributed control system.

3.1.2.3 *Air Flow Limitations*

Appropriate air flow is required to provide enough air for combustion to enable units to provide full output. The Holyrood units have experienced air flow limitations since 2015. Deratings have resulted from fouling of the air heaters and boiler sections including the economizer, and from air heater leakage. Fouling and air heater leakage has led to the inability of the boiler fans to provide sufficient air flow for operation at high loads. Also, fouling has caused a back pressure in the furnace that increases with load, which can result in requirements to limit load. Significant deratings were observed through the 2017-2018 winter operating season.

In 2017, Hydro engaged boiler OEM, B&W, and an outside consultant to complete an engineering study of the issues and provide new recommendations for consideration and resolution. The results of this study determined the three primary causes of boiler derating to be:

1) Air heater fouling in all units;
2) Air heater leakage in Unit 3;[11] and
3) Economizer fouling in Unit 1 and Unit 2.[12]

Based on the results of the engineering study, a supplemental capital budget application was prepared and approved by the Board to replace air heater baskets in all units and correct the air

[11] Unit 1 and Unit 2 air heater leakage was addressed in 2017.
[12] Unit 3 has a different design economizer that is not prone to excessive fouling.

heater leakage in Unit 3 to significantly improve the unit capabilities. The Unit 1 and Unit 2 baskets were replaced during the planned 2018 annual outages. An outage was taken in October 2018 on Unit 3 to complete the basket replacement and correct the air heater leakage.

In addition, the Unit 1 and Unit 2 economizers were chemically washed by an experienced boiler cleaning contractor. The chemical wash was effective in removing all fouling from approximately 70 percent of the economizer flow area in both units, resulting in a significant improvement in back pressure in the furnace.

B&W observed that the discontinuance of use of the Magnesium Oxide fuel additive in 2014 also contributed to the observed decline in unit performance. The decision to discontinue use of the fuel additive was based on the improved fuel oil supply specification, which reduced quantities of vanadium and other metals in the fuel to near zero. The subsequent impact on fouling at the air heaters was not known. Use of the fuel additive has been reinstated for all units.

All units are expected to have capability of achieving full load when returned to service.

As a result of the work completed during the outage season, all units are expected to have capability of achieving full load heading into the 2018-2019 winter period.

- Unit 1 was operated to 140 MW but limited at that load until online safety valve testing can be completed by a contractor. Operating parameters at that load demonstrated that the air flow issues have been successfully addressed and the ability to reach full load is expected.
- Unit 2 has been load tested at full load capability and is currently rated at 170 MW.
- Unit 3 has been load tested to 145 MW and could likely have achieved full load of 150 MW, however external system conditions did not permit the unit to be operated at a higher load at the time of the load test.

Unit capabilities will be maintained through sootblower operation, maintenance of the fuel additive system, air heater washes, and control of operational parameters. Unit capabilities will be tested throughout the 2018-2019 winter operating season.

3.1.2.4 *Unit 1 and Unit 2 Hydraulic Fluid Condition*

Hydro has observed contamination in the hydraulic fluid that is used to operate the Unit 1 and Unit 2 turbine valves.[13] The level of fluid contamination observed during the 2017-2018 operating season required fluid and filter replacement.

As a mitigating measure, flushing was completed during the annual outage for both units to replace the fluid and clean the systems. However, issues have been observed on Unit 1 since start-up and additional work is required to further clean the system to ensure reliable operation of the hydraulic system. A GE Technical Advisor is leading this flushing effort on-site. The Technical Advisor will also advise if additional flushing is required for Unit 2.

Hydro will continue to perform monthly fluid sample analyses during the 2018-2019 winter operating season and take action, if required, to ensure reliable operation of the units.

3.1.3 Gas Turbines

3.1.3.1 *End A Unavailability at Stephenville*

On December 27, 2017, Stephenville End A tripped while attempting to switch from synchronous condenser operation to generate mode. The cause of the trip was determined to be an issue with the rear power turbine bearing which required the replacement of the bearing. The bearing was replaced in July 2018. However, the power turbine could not be tested until the bellows and refurbished engine were commissioned on October 6, 2018. While the vibration issue affecting the power turbine has improved, it is still resulting in trips of End A.

[13] Contamination has been observed through regular sampling. On March 22, 2018, the contamination resulted in a forced outage on Unit 2. On April 3, 2018, Unit 2 was taken off-line for repair of the hydraulic ram for the turbine control valves.

Further detailed vibration analysis of the power turbine has determined that the issue relating to the rear bearing has been resolved. However, it has also been determined that the vibration detection system is being affected by electrical noise resulting in false high vibration readings. Repairs to the vibration system are currently scheduled for November 2018. It is anticipated that End A will be released for service prior to December 1, 2018.

3.1.3.2 *Combustion Can Failures at Hardwoods*

Two engines installed in Hardwoods experienced combustion can failures in 2017.[14] In both cases, the can failure occurred at the location of riveted bands within the combustion can. Both engines were returned to the overhaul facility to have the combustion cans replaced with an upgraded combustion can which is of welded rather than riveted construction. Repairs and upgrades were completed at the overhaul facility and the engines were returned to Hydro. This issue is considered resolved.

3.1.3.3 *Hardwoods Bellows Cracking*

On May 28, 2018, Hardwoods End A became unavailable due to an exhaust bellows failure. The damaged bellows was removed and sent to a local welding shop for repair. End A was returned to service on July 25, 2018. This issue is considered resolved.

3.2 Selection of Appropriate Performance Ratings

3.2.1 Consideration of Asset Reliability in System Planning

Hydro’s asset reliability is a critical component in determining its ability to meet planning criteria for the NLIS. As an input to the assessment of resource adequacy, unit forced outage rates (“FOR”) provide a measure of the expected level of availability due to unforeseen circumstances.

[14] In February, Hardwoods engine 202224 failed while in service due to a lube oil leak internal to the engine. A borescope inspection completed post-failure also identified an imminent combustion can failure, but prior to full failure, which in the past has occurred and caused material damage to the rest of the engine. In August, a planned borescope inspection of the engine (serial number 202205) identified another combustion can failure.

The forced outage rate methodology applied in the "Reliability and Resource Adequacy Study" varied by asset class, ownership, and condition. FOR were determined based on historical data, where available, or the most recent industry average. The historical data is based on a weighted average of DAFOR for Holyrood and hydroelectric units, and DAUFOP for gas turbine units. Analysis was performed for a range of Holyrood DAFOR assumptions to provide an indication of the sensitivity of supply adequacy to changes in Holyrood availability. For units not owned by Hydro, Canadian Electricity Association ("CEA") or NERC industry standards were used.

FOR assumptions will be re-evaluated annually to incorporate the most recent data available.

FOR assumptions will be re-evaluated on an annual basis to incorporate the most recent data available. A detailed description of the development of the FOR assumptions used is found in Volume I, Attachment 5 of the Study. Table 1 summarizes the projected availability of Hydro's generating assets considered in the assessment of near-term supply adequacy. These projections of asset reliability include appropriate consideration of asset availability and deration.

Table 1: Summarized Asset Reliability Metrics

Asset	Reliability Metric
Hydraulic Units	DAFOR = 3.5%
Holyrood Thermal Units	DAFOR = 15%, 18%, 20%
Holyrood Gas Turbine	DAUFOP = 2.2%
Happy-Valley Gas Turbine	DAUFOP = 13.9%
Stephenville Gas Turbine	DAUFOP = 30%
Hardwoods Gas Turbine	DAUFOP = 30%

3.3 Asset Retirement Plans

3.3.1 Holyrood Thermal Generating Station

Holyrood Units 1 and 2 were commissioned in 1971 and Unit 3 was commissioned in 1979. The three units combined provide a total firm capacity of 490 MW. All three units are anticipated to retire following the in-service of the Muskrat Falls Generating Station.

3.3.2 Hardwoods and Stephenville Gas Turbines

The Stephenville Gas Turbine consists of two, 25 MW gas generators that were commissioned in 1975. The Hardwoods Gas Turbine consists of two, 25 MW gas generators that were commissioned in 1976. Each of the plants provide 50 MW of firm capacity to the system. These units were designed to operate in either generation mode to meet peak and emergency power requirements or synchronous condense mode to provide voltage support to the Island Interconnected System ("IIS"). While Hydro had intended to retire these assets later in the 2020s, the criteria for dispatching the units materially changed in 2014, resulting in increased frequency and duration of operation. As such, there have been operational issues in recent years that have impacted the reliability of the plants and resulted in increased maintenance costs. Hydro plans to confirm retirement plans of these assets following stakeholder review of the 2018 "Reliability and Resource Adequacy Study."

4 Load Forecast

4.1 Load Forecasting

A detailed discussion of the load forecast process and load forecast used is provided in Volume III, Section 5 of the Study. As the analysis now focuses on the NLIS adequacy, a combined NLIS forecast was required. For the purposes of the near-term resource adequacy assessment, the Case I: Low Retail Rate forecast was used as the basis for the IIS requirements, while both the base and high industrial load growth cases were used for the Labrador Interconnected System.

5 System Constraints and Future Supply Risk

To fully understand the potential supply risk posed to the IIS, both energy and capacity analysis was conducted.

5.1 System Energy Capability

To reduce overall system costs, economy energy was imported over the ML in advance of the 2018-2019 winter season.

Testing and commissioning continues on the LIL and it is expected to be in service for the 2018-2019 winter season.

During September 2018, as part of Hydro's water management process, the Vista Decision Support System recommended the need for additional energy production to supplement hydraulic production given low reservoir levels. Throughout early October 2018, increasingly more historic sequences showed the need for additional energy production to mitigate low system storage. In order to be proactive and to reduce overall system costs throughout winter 2018-2019 through the reduction of Holyrood generation, economy energy was imported over the Maritime Link in October 2018 to increase energy in storage and offset thermal generation at Holyrood. Significant rainfall events over all reservoir basins occurred in late October 2018, increasing the system energy in storage to 1,672 GWh at the end of October 2018;[15] system energy in storage was 53 percent above the minimum storage target of 1,095 GWh.

The Labrador-Island Link ("LIL") commissioning activities resumed on November 1, 2018, allowing recapture energy to be delivered to the IIS via the LIL. Hydro's current conservative assumptions for the

[15] A net increase in energy in storage of 431 GWh from October 16, 2018.

LIL availability is 110 MW with a 30 percent FOR with testing and commissioning energy expected through the end of 2018 and operation commencing January 1, 2019.

Hydro will accept higher deliveries and potentially more energy once the LIL has proven to be reliable and is accepted by the NLSO.

Hydro's energy in storage remains above its established minimum storage target and, therefore, current reservoir levels show that available energy within Hydro's Hydraulic Generation System is not a risk to supply for the 2018-2019 winter season.

The availability of energy does not currently pose a risk to near-term supply adequacy.

6 Results

The following subsections provide the LOLH, EUE, and normalized EUE results for the cases considered. Similar to previous near-term resource adequacy analysis, DAFORs ranging from 15 to 20 percent were used for Holyrood. On October 1, 2018, Hydro provided a contingency plan to the Board to mitigate system exposure in the case that the LIL was not available as currently anticipated. Since that time Hydro has actioned all aspects of that contingency plan.[16] With the exception of the case which includes current operational capability, the attributes of the contingency plan are included in the results presented. Results are also presented for a case considering a further delay in LIL to in-service following the winter 2018-2019 operating season. Testing and commissioning continues on the LIL and it is expected to be in service for 2018-2019 winter season. Hydro continues to keep the Board apprised of the status of the LIL via the "Labrador-Island Link In-Service Update."

[16] "Labrador-Island Link In-Service Update."

6.1 EUE and LOLH Analysis

Sections 6.1.1 and 6.1.2 provide the results of the annual and monthly analysis, respectively.

6.1.1 Annual Assessment Results

Table 2 provides the annual LOLH, EUE and normalized EUE results. Where cases are no longer relevant (i.e., the increase in DAFOR for Holyrood plant no longer varies the LOLH or EUE once it is retired), the results have been noted as not applicable ("N/A").

Table 2: Annual LOLH, EUE, and Normalized EUE Results

Reliability Metric					
LOLH (hours)	**2019**	**2020**	**2021**	**2022**	**2023**
Existing Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 15%	2.56	0.61	0.05	0.23	0.36
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 15%	2.21	0.59	0.05	0.23	0.37
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 18%	3.31	0.91	0.05	N/A	N/A
Increased Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 20%	4.13	1.15	0.04	N/A	N/A
Contingency Plan Implemented, Labrador High Industrial Load Forecast, Holyrood DAFOR = 15%	2.25	0.61	0.07	0.32	0.61
Contingency Plan Implemented, Labrador Base Load Forecast, the LIL Delayed to July 2019, Holyrood DAFOR = 15%	4.61	N/A	N/A	N/A	N/A
EUE (MWh)	**2019**	**2020**	**2021**	**2022**	**2023**
Existing Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 15%	139	31	4	18	29
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 15%	118	29	4	18	30
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 18%	184	46	4	N/A	N/A
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 20%	230	60	3	N/A	N/A
Contingency Plan Implemented, Labrador High Industrial Load Forecast, Holyrood DAFOR = 15%	120	29	5	23	44
Contingency Plan Implemented, Labrador Base Load Forecast, the LIL Delayed to July 2019, Holyrood DAFOR = 15%	253	N/A	N/A	N/A	N/A
Normalized EUE (ppm)	**2019**	**2020**	**2021**	**2022**	**2023**
Existing Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 15%	12.9	2.9	0.4	1.6	2.7
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 15%	11.0	2.7	0.4	1.7	2.8
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 18%	17.0	4.3	0.3	N/A	N/A
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 20%	21.2	5.6	0.3	N/A	N/A
Contingency Plan Implemented, Labrador High Industrial Load Forecast, Holyrood DAFOR = 15%	10.9	2.7	0.4	2.0	4.0
Contingency Plan Implemented, Labrador Base Load Forecast, the LIL Delayed to July 2019, Holyrood DAFOR = 15%	23.4	N/A	N/A	N/A	N/A

The results indicate increased exposure through the 2018-2019 winter season for Holyrood unavailability in excess of 15 percent and in the case of the unavailability of the LIL through the operating season. This risk is mitigated to within existing planning criteria when the proposed incremental capacity assistance[17] is included in the analysis.

Post-2019, reliability metrics for all subsequent years are within planning criteria.

6.1.2 Monthly Assessment Results

Table 3 through Table 7 provide monthly analyses of LOLH and EUE, by year. The monthly analyses provide additional detail that assists in examining the complexity of the changing power system that would not necessarily be apparent from an analysis of the annual results only. Completing monthly analyses allows for easier identification of changes in system behaviour. For example, if a system had a change in forecast peak demand with no resultant change in annual LOLH or EUE, the monthly analysis would indicate where differences in LOLH and EUE were anticipated, allowing for better understanding of the drivers of the annual results. This type of analysis is used by NERC to complement its long-term reliability assessments.

For 2019, high values of LOLH and EUE are observed during winter months, with both LOLH and EUE growing as Holyrood unavailability increases. The increase in reserve margin provided by the availability of increased capacity assistance from currently contracted values reduces the LOLH and EUE through the winter months. The small values of LOLH and EUE observed in summer months are largely attributed to an anticipated multi-week outage on the LIL.

[17] As per Hydro's applications to the Board on November 2, 2018 (Corner Brook Pulp and Paper) and November 14, 2018 (Vale).

In 2020, LOLH and EUE are observed to decline as generation becomes available at Muskrat Falls Generating Station, following the in-service of the first unit, expected in the third quarter of 2019. Values of LOLH and EUE observed continue to decline as more units become available at the Muskrat Falls Generating Station.

In 2021, LOLH and EUE are virtually zero as both Muskrat Falls Generating Station and Holyrood are both in service and available to meet customer requirements.

Following the retirement of Holyrood, small values of LOLH and EUE are observed in the winter operating season.

Table 3: Monthly LOLH and EUE for 2019

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 15%	0.96	0.59	0.42	0.02	0.01	0.00	0.04	0.02	0.02	0.00	0.00	0.49
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 15%	0.79	0.46	0.36	0.02	0.01	0.00	0.03	0.02	0.02	0.00	0.00	0.50
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 18%	1.21	0.69	0.53	0.03	0.02	0.00	0.04	0.03	0.02	0.00	0.00	0.74
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 20%	1.53	0.88	0.65	0.04	0.02	0.00	0.05	0.02	0.02	0.00	0.00	0.91
Contingency Plan Implemented, Labrador High Industrial Load Forecast, Holyrood DAFOR = 15%	0.81	0.47	0.34	0.02	0.01	0.00	0.04	0.03	0.02	0.00	0.00	0.50
Contingency Plan Implemented, Labrador Base Load Forecast, the LIL Delayed to July 2018, Holyrood DAFOR = 15%	1.97	1.11	0.85	0.05	0.03	0.00	0.04	0.03	0.02	0.00	0.00	0.50
EUE (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Existing Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 15%	51	31	23	1	1	0	2	1	1	0	0	28
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 15%	42	24	19	1	1	0	1	1	0	0	0	29
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 18%	67	37	29	2	1	0	1	1	1	0	0	44
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 20%	84	48	37	2	1	0	2	1	0	0	0	55
Contingency Plan Implemented, Labrador High Industrial Load Forecast, Holyrood DAFOR = 15%	44	25	18	1	1	0	1	1	1	0	0	29
Contingency Plan Implemented, Labrador Base Load Forecast, the LIL Delayed to July 2018, Holyrood DAFOR = 15%	111	60	47	2	2	0	2	1	1	0	0	29

Table 4: Monthly LOLH and EUE for 2020

LOLH (hours)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Existing Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 15%	0.30	0.17	0.06	0.00	0.00	0.00	0.02	0.06	0.00	0.00	0.00	0.00
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 15%	0.28	0.18	0.06	0.00	0.00	0.00	0.02	0.05	0.00	0.00	0.00	0.00
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 18%	0.44	0.28	0.11	0.00	0.00	0.00	0.03	0.05	0.00	0.00	0.00	0.00
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 20%	0.59	0.36	0.12	0.01	0.00	0.00	0.03	0.04	0.00	0.00	0.00	0.00
Contingency Plan Implemented, Labrador High Industrial Load Forecast, Holyrood DAFOR = 15%	0.28	0.18	0.06	0.00	0.00	0.00	0.02	0.06	0.00	0.00	0.00	0.00
EUE (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Existing Capacity Assistance, Labrador Base Load Forecast, Holyrood DAFOR = 15%	16	9	3	0	0	0	1	3	0	0	0	0
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 15%	14	9	3	0	0	0	1	2	0	0	0	0
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 18%	22	14	6	0	0	0	1	2	0	0	0	0
Contingency Plan Implemented, Labrador Base Load Forecast, Holyrood DAFOR = 20%	31	18	7	0	0	0	1	2	0	0	0	0
Contingency Plan Implemented, Labrador High Industrial Load Forecast, Holyrood DAFOR = 15%	14	9	3	0	0	0	1	2	0	0	0	0

Table 5: Monthly LOLH and EUE for 2021

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Capacity Assistance, Labrador Base Load Forecast	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04
Contingency Plan Implemented, Labrador Base Load Forecast	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
Contingency Plan Implemented, Labrador High Industrial Load Forecast	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.06
EUE (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Existing Capacity Assistance, Labrador Base Load Forecast	0	0	0	0	0	0	0	0	0	0	0	3
Contingency Plan Implemented, Labrador Base Load Forecast	0	0	0	0	0	0	0	0	0	0	0	3
Contingency Plan Implemented, Labrador High Industrial Load Forecast	0	0	0	0	0	0	0	0	0	0	0	3

Table 6: Monthly LOLH and EUE for 2022

LOLH (hours)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Existing Capacity Assistance, Labrador Base Load Forecast	0.06	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.09
Contingency Plan Implemented, Labrador Base Load Forecast	0.06	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.08
Contingency Plan Implemented, Labrador High Industrial Load Forecast	0.07	0.07	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.13
EUE (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Existing Capacity Assistance, Labrador Base Load Forecast	5	3	2	0	0	0	0	0	0	0	0	7
Contingency Plan Implemented, Labrador Base Load Forecast	5	4	2	0	0	0	0	0	0	0	0	6
Contingency Plan Implemented, Labrador High Industrial Load Forecast	5	5	3	0	0	0	0	0	0	0	1	9

Table 7: Monthly LOLH and EUE for 2023

LOLH (hours)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Existing Capacity Assistance, Labrador Base Load Forecast	0.10	0.11	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.08
Contingency Plan Implemented, Labrador Base Load Forecast	0.10	0.11	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.08
Contingency Plan Implemented, Labrador High Industrial Load Forecast	0.17	0.19	0.08	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.16
EUE (MWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Existing Capacity Assistance, Labrador Base Load Forecast	9	9	4	1	0	0	0	0	0	0	1	6
Contingency Plan Implemented, Labrador Base Load Forecast	9	9	4	1	0	0	0	0	0	0	1	6
Contingency Plan Implemented, Labrador High Industrial Load Forecast	12	14	6	0	0	0	0	0	0	0	1	10

7 Conclusion

Hydro closely monitors its supply-related assets to ensure its ability to provide reliable service to customers. As previously identified by both Hydro and the Board's Consultant, The Liberty Group, the availability of power over the LIL remains an important part of Hydro's supply adequacy in advance of the availability of generation from the Muskrat Falls Generating Station. Hydro is working closely with Nalcor's Power Supply leadership to monitor and mitigate the risks associated with the timing of the in-service of the LIL to supply off-Island capacity and energy to the IIS. Following the full in-service of the Lower Churchill Project assets and the retirement of Holyrood, small values of LOLH and EUE continue to be observed in winter months (i.e., during time of system peak), however values are materially reduced from those observed in 2019.

The availability of power over the LIL remains an important part of Hydro's supply adequacy in advance of the availability of generation from Muskrat Falls.

Reliability and Resource Adequacy Study

Volume III: Long-Term Resource Plan

November 16, 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

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1 Introduction

Volume III of Hydro's Reliability and Resource Adequacy Study ("Study") addresses the long-term resource plan that is required to meet the reliability expectations defined in Volume I of the Study. Specifically, the analysis comprehensively evaluates resource options to meet projected future customer demand and energy requirements at least-cost through to 2028. Newfoundland and Labrador Hydro ("Hydro") proposes the analysis contained in Volume III will be filed with the Board of Commissioners of Public Utilities ("Board") annually in November.

The resource plan determines the least-cost additional resources required based on the reserve margin targets established by the Reliability Model,[1] as presented in Volume I of this Study, over the ten-year study period. Key inputs to the Plan include the long-term load forecast, resource options and costing, and other forecasts (e.g., fuel, escalation, market prices, etc.). The resource plan also considers the environmental, sustainability, and reliability attributes of all resource options considered.

The resource planning process determines the least -cost additional resources required based on the reserve margin targets established by the Reliability Model over a ten- year study period.

To ensure preliminary alignment with Study deliverables, key stakeholders were engaged throughout the Study process. Stakeholders included the Consumer Advocate, Newfoundland Power, each of Hydro's Industrial Customers, and electricity consumers across the province. Stakeholders generally expressed that the methodology of the study was comprehensive. Hydro incorporated the stakeholder engagement feedback in the Study.

[1] The reliability model is used to assess anticipated system reliability during the forecast to determine the target planning reserve margin that must be held to satisfy reliability requirements.

From a risk perspective, it is noted that the inputs for the resource planning process are not precise. While many variables, including forecast retirements and asset health for example, are analyzed to understand the implications and interaction of inputs and impacts on costs and rates, by nature these variables include uncertainty. At this time, four variables in particular contribute to the majority of variation observed between identified resource plans:

- **The difference in forecast peak demand associated with the considered range of retail rates for the Island Interconnected System ("IIS");**
- **the availability of supply in Labrador to fully utilize the Labrador-Island Link ("LIL") for deliveries to the Island over peak through the study period;**
- **the difference between the use of P90 versus P50 peak demand forecast in supply planning as the base for the IIS forecast; and**
- **the option to mitigate the unserved energy resulting from the event that the LIL becomes unavailable for a prolonged period at time of system peak.**

As such, the results of this Study provide an opportunity for discussion with stakeholders on key decision inputs to be used in the future planning of the Newfoundland and Labrador Integrated System ("NLIS"). Further optimization of results will be undertaken, as required to support decision-making, and also as part of the annual planning exercise. By conducting this analysis annually, the impact of any changes in key inputs that materialize over the course of the year will be included in Hydro's analysis in a timely manner.

The target in-service dates of planned resources and planned retirements, as known at this time, are reflected in the study.

The Planning Reserve Margin, detailed in Volume I of the Reliability and Resource Adequacy Study, forms the basis for the addition of incremental resources identified in the Resource Planning process. Another case, which contemplates the investment required to partially and fully mitigate unlikely loss-of-supply events, including the loss of the LIL, is also considered in this analysis. In that case, the decision to invest in incremental supply is not to satisfy the planning reserve margin, but rather a choice to be made specific to the jurisdiction.

Several potential resource options, including associated transmission requirements and minimum of class 5 cost estimates[2] were developed in support of the resource planning study.[3]

This process seeks to minimize power supply costs and risks while maintaining a high degree of system reliability. Conducting forward looking analysis ensures that there is clear line of sight to the timing of incremental resource additions, with the flexibility to react to changes in load forecasts, legislative and regulatory requirements, new technologies, and market price volatilities. Conducting the analysis annually ensures that the recommended courses of action continue to provide the optimal alternative for Hydro's customers in consideration of both cost and reliability.

This process seeks to minimize power supply costs and risks while maintaining a high degree of system reliability

2 Stakeholder Engagement

To complement the technical efforts which form the foundation of the analysis, this Study includes consideration of Hydro's findings from stakeholder consultations to fully inform the recommended resource plan. This involved direct consultation, specifically focused on reliability

[2] The AACE International Cost Estimate Classification System provides guidelines for applying the general principles of estimate classification to project cost estimates. The system has five classes of estimates. Class 5 cost estimates are generally prepared based on very limited information and subsequently have wide accuracy ranges. Class 5 estimates are prepared for strategic business planning purposes such as assessment of initial viability, evaluation of alternatives, budgeting, and long range capital planning. The typical accuracy range for class 5 estimates are -20% to -50% on the low side to +30% to +100% on the high side.
[3] Estimates were supported by external consultants where appropriate.

and resource planning, with Newfoundland Power, Hydro's Industrial Customers, the Consumer Advocate, and provincial electricity customers.

2.1 Industrial Customers

Hydro met with industrial customers [i.e., Corner Brook Pulp and Paper Limited ("CBPP"), Praxair Canada Inc., Teck Resources Limited ("Teck"), and Vale Newfoundland and Labrador Limited ("Vale")] to provide an overview of the Study. The presentation explained the methodology for the Study itself, the use of new software to enhance technical analysis, the ongoing review of other utility practices in North America, and the timing for the sharing of study results with the Board.[4] The stakeholders were given the opportunity to ask questions and provide feedback. Overall, the industrial customers generally agreed with the proposed approach for study execution, with many commenting on the comprehensiveness of the presented project scope.[5]

2018 Digital Engagement Initiative:

- **Opt-in approach**
- **Short information videos and online survey**
- **Aug. 28, 2018 to Sept. 20, 2018**
- **2,070 completed surveys**

2.2 Residential/Commercial Customers[6]

Hydro worked with National Public Relations, an external communications consultant, and Corporate Research Associates ("CRA") to implement a digital engagement initiative designed to provide an opportunity for residents and businesses to become actively engaged in the conversation on electricity in the province. The

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[4] Volume III, Attachment 1 "2018 Reliability Review and Supply Adequacy Assessment" contains a copy of the presentation shared with Industrial Customers.

[5] For copies of meeting minutes and correspondence from the engagement with Industrial Customers, please refer to Volume III, Attachment 2. Note that the presentation referenced in the meeting minutes and correspondence is the same presentation included as Volume III, Attachment 1.

[6] For more information refer to Volume III, Attachment 3 "2018 Digital Engagement Initiative," October 2018.

engagement used an opt-in approach, providing for an opportunity for all residents in the province to join in the conversation. While no quotas for data collection were implemented, a total of 2,070 surveys were completed during the study period. The engagement was open from August 28, 2018 to September 20, 2018. The engagement was the first step in Hydro's longer term plan to engage electricity customers in its decision. The engagement results were not intended to provide statistically meaningful results, but rather to actively engage residents in the discussion. Residents were encouraged to visit a website and share their thoughts by reviewing a series of short information videos and completing an online survey. The survey provided qualitative information that was used to inform recommendations and key conclusion of the Study.

The digital engagement initiative provided an opportunity for input and feedback from electricity customers on various topics related to the future of Newfoundland and Labrador's electricity system including:

- **Overall perceptions regarding the reliability of current system among residents across the province;**
- **Opinions regarding the appropriate balance between reliability and the cost of those investments for customers;**
- **Residents' interest in taking a more active role in managing their electricity consumption and additional rate structure and pricing options; and**
- **Residents' level of interest in engagement with Hydro on a go-forward basis.**

The vast majority of the 2,070 respondents were homeowners, with some participation by business owners. After watching a series of short videos, participants were asked questions about three main topics: current electricity reliability, reliability and required investment, and customer options for electricity consumption.

The results of the 2018 digital engagement initiative indicate that respondents are generally content with the performance of the existing system. The majority of respondents report that their power reliability has improved since the outages experienced in 2013 and 2014.

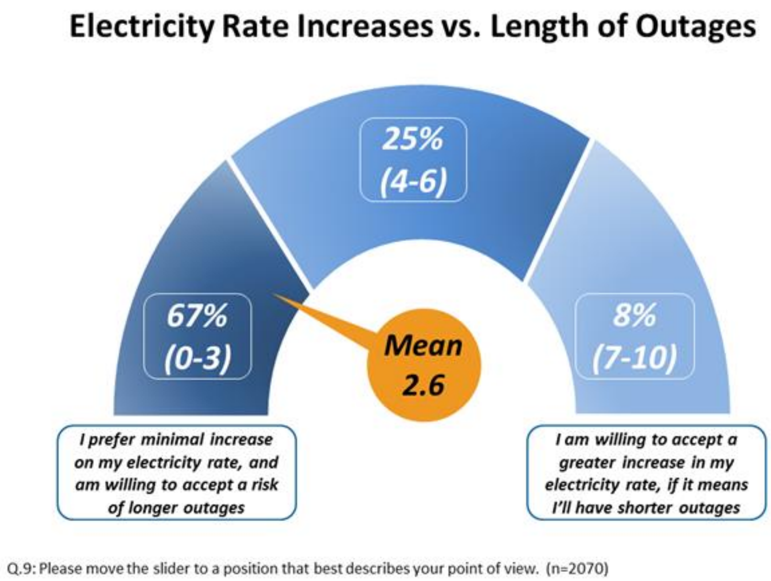


Figure 1: Electricity Rate Increases vs. Length of Outages Response

Results showed respondents are clearly cost-sensitive, with many expressing willingness to accept a risk of longer outages in favour of minimal rate increases; however, customers expressed the tolerance for outages does have a limit, with few customers indicating tolerance for more than three outages per year.

To provide an opportunity for continued active engagement in the conversation on electricity in the province, Hydro is establishing an Electricity Feedback Panel ("Panel"). The Panel will provide Hydro with a pool of interested parties who will provide opinions and feedback to Hydro through online survey participation.

63% of respondents from the digital engagement initiative showed interest in joining Hydro's Electricity Feedback Panel to provide feedback on various topics or issues in the future.

2.2.1 Current Electricity Reliability

To better understand current perceptions regarding overall reliability of the province's electricity system, participants were asked to rate the reliability of electricity they received. Fifty-six percent (56%) of respondents reported experiencing one to three outages in the last 12 months with the average overall reported length being 2.9 hours. Across regions, residents in Labrador reported the highest frequency (58% indicated 5+ outages in last year) and duration of outages (last outage indicated to have a duration of an average of 5.6 hours).

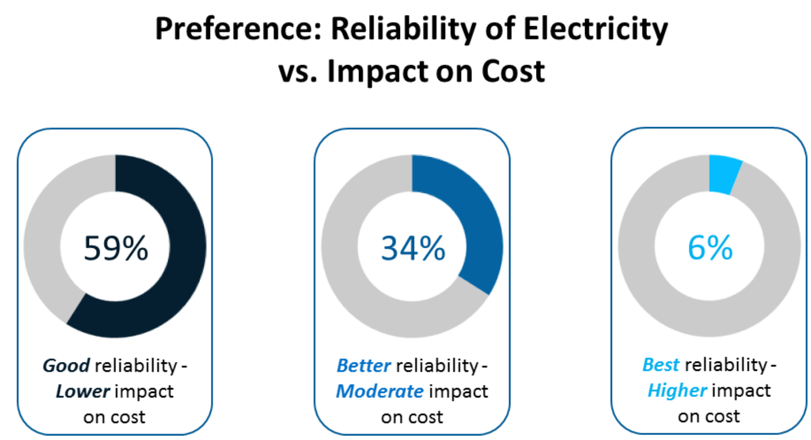
Fifty-seven percent (57%) of the respondents felt their electricity reliability has improved since the outages experienced in 2013 and 2014, and 47% suggested a requirement for a more reliable system.

2.2.2 Reliability and Cost of Investment

Respondents were asked to rate their level of agreement on statements related to future system investment. Overall, respondents generally expressed comfort with Newfoundland and Labrador's current electricity system and are reluctant to support additional generation investments. Seventy-one percent (71%) of respondents expressed comfort with the system's current level of reliability and a preference that additional investment is made cautiously. However, 31% of respondents believe that Hydro should invest in more generation to further reduce the impact of power supply interruptions during extreme events.

Given that additional investment will result in increased electricity rates, 67% of respondents indicated a preference for a minimal increase in their electricity rates and a willingness to accept a risk of longer outages. Eight percent (8%) of respondents reporting a willingness to accept a greater increase in their electricity rate, though it would mean experienced outages would likely be shorter.

When presented with three options related to reliability and cost, 59% of respondents indicated a preference for good reliability with a lower impact on electricity cost, 34% of respondents selected better reliability with moderate impact on cost, and 6% of respondents selected best reliability with a higher impact on cost. Regardless of the indicated preferred approach, the majority of respondents deem one to two outages per year to be acceptable, and very few deem more than three outages a year to be acceptable.



Q.10: Please select the alternative that best describes your preference. (n=2070)

2.2.3 Customer Options for Electricity Consumption

The third focus topic was designed to gauge consumer interest in options aimed at providing more choice and control over electricity consumption and overall costs. Overall, 81% of respondents agree that customers should take an active role in managing their electricity consumption, with 77% noting that they would like to better understand their electricity usage at any time in the day, in real time. Seventy-three (73%) of respondents believe there should be more customer rate options so they can better manage their monthly electricity costs, with similar response profiles observed by both individuals and surveyed business owners. Of the options suggested by respondents, time-of-day usage rates was the most frequently suggested.

2.3 Other Stakeholder Engagement

Stakeholders were given opportunities to provide input on study considerations and methodology, with recommendations incorporated

Hydro consulted with Newfoundland Power and the Consumer Advocate in the development of study scope and areas of focus throughout the study execution. As the majority of retail customers on the IIS are served by Newfoundland Power, Newfoundland Power executives were consulted on the overall study methodology and the customer engagement strategy. Additionally, Newfoundland Power staff was engaged on matters including the modelling of Newfoundland Power assets in Hydro's models, the consideration of rate design as a resource option, and Customer Demand Management. In consultation with the Consumer Advocate, it was noted that the inclusion of Customer Demand Management and rate design as potential resource options marked a positive step forward. The Consumer Advocate stated that customers continue to be concerned about future electricity costs and would likely benefit from additional flexibility and options. Stakeholders were provided with opportunities to provide input on study considerations and methodology, with recommendations incorporated.

3 Existing Assets and Infrastructure

Hydro's existing assets and infrastructure continue to play a key role in its supply mix through the study period. Outlined within this section is an overview of the existing assets and infrastructure that are part of the NLIS generation resources and are integrated in the Study's long-term planning modelling. The availability and reliability of these existing assets is a key input to the resource planning process, ensuring that the system is not overly relying on assets, and that the firm capability and forced outage rates are appropriately considered. The long-term resource planning model ("Resource Planning Model") uses the criteria determined using the Reliability Model to determine the least-cost alternative to meet system reliability expectations. The majority of the assumptions made in the Resource Planning Model are consistent with those made in the Reliability Model. For ease of reading, the assumptions have been reproduced in the following sections of this Study, with notable differences highlighted. For more detailed information on forced outage rates used in the analysis, please refer to Volume I, Attachment 5 of this Study.

3.1 Hydroelectric Generation

Table 1 and Table 2 provide a summary of the capability of Hydro's owned hydraulic generating units and the Muskrat Falls Generating Station ("MFGS").

Table 1: Capacity of Hydraulic Generating Units

Hydraulic Unit	Installed Capacity (MW)	Gross Continuous Unit Rating (MW)
Muskrat Falls		
Unit 1	206.0	197.5
Unit 2	206.0	197.5
Unit 3	206.0	197.5
Unit 4	206.0	197.5
Total Muskrat Falls Plant [7]	**824.0**	**790.0**
Bay d'Espoir		
Unit 1	76.5	76.5
Unit 2	76.5	76.5
Unit 3	76.5	76.5
Unit 4	76.5	76.5
Unit 5	76.5	76.5
Unit 6	76.5	76.5
Unit 7	154.4	154.4
Total Bay d'Espoir Plant	**613.4**	**613.4**
Cat Arm		
Unit 1	68.5	67.0
Unit 2	68.5	67.0
Total Cat Arm Plant	**137.0**	**134.0**
Other Hydro		
Hinds Lake	75.0	75.0
Granite Canal	40.0	40.0
Paradise River	8.0	8.0
Upper Salmon	84.0	84.0
Mini Hydro	4.0	0.0
Total Other Hydro	**211**	**207.0**
Total Hydraulic Generation	**1785.4**	**1744.4**

[7] Quantity reported at Muskrat Falls. Difference in Installed Capacity and Gross Capacity is related to potential tailrace icing conditions in the Churchill River in the winter period.

Table 2: Energy Capability of Island Hydraulic Facilities

Hydraulic Facilities	Firm (GWh)	Average (GWh)[8]
Bay d'Espoir	2,272	2,650
Cat Arm	678	755
Hinds Lake	290	354
Granite Canal	191	246
Paradise River	33	35
Upper Salmon	492	556
Total Hydraulic Generation	**3,956**	**4,596**

Existing on-island hydraulic generation is anticipated to continue to produce an average of 4,600 GWh of energy annually. Energy from the MFGS will be provided to Hydro in accordance with annual entitlements, starting at 2 TWh per year and growing to 2.5 TWh within the study period.

MFGS and Bay d'Espoir are the largest energy producing facilities in the NLIS. Figure 2 shows the monthly energy profile assumed for these units. From the profiles presented it is seen that the large storage potential at Bay d'Espoir allows generation at the facility to follow the system load shape, while the generation profile for MFGS shows the seasonality associated with lower flow through the end of winter and increased production in the spring run-off period.

[8] Based on energy presented in Hydro's "2017 General Rate Application."

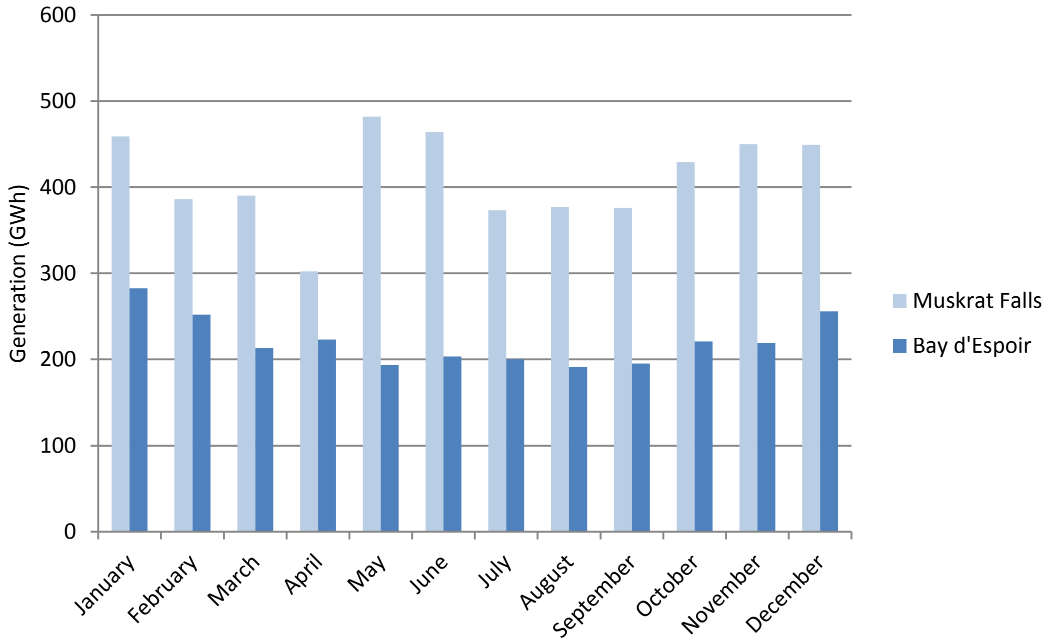


Figure 2: Muskrat Falls and Bay d'Espoir Generation Profile

1 Figure 3 shows the energy profiles modeled for other hydraulic generation in the system.

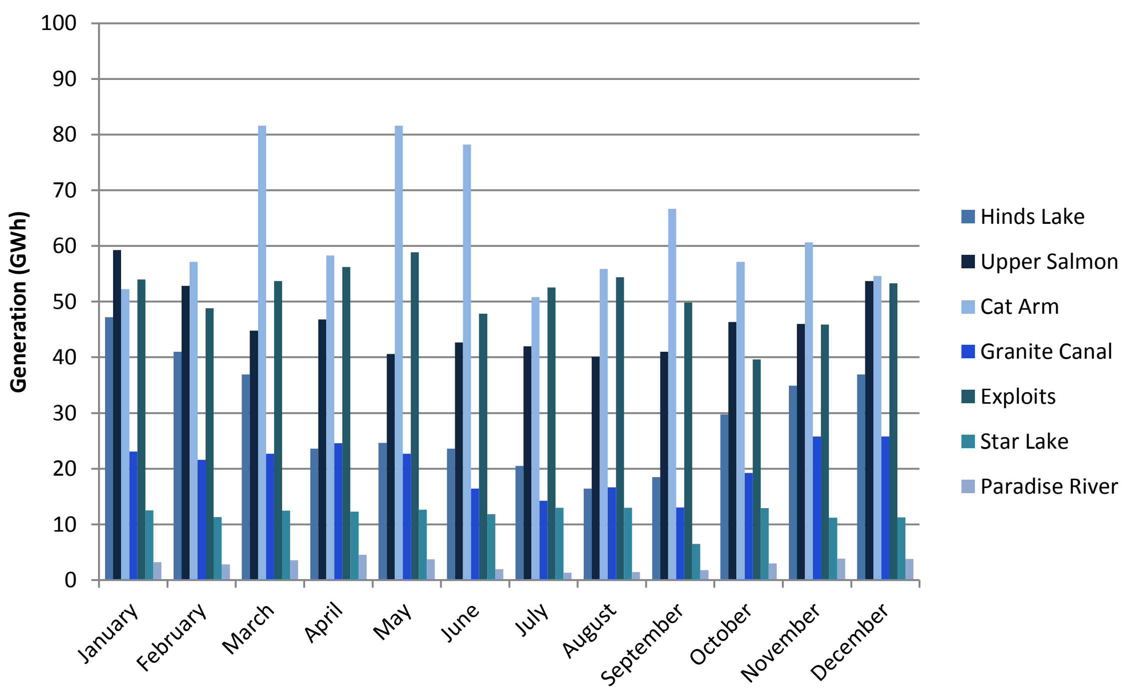


Figure 3: Remaining Hydraulic Assets Generation Profile

3.2 Power Purchase Agreements

There are currently power purchase agreements ("PPAs") for the purchase of wind, hydroelectric, and thermal generation. These contracted resources are included in the resource planning model with the respective firm capacity, generation, and contract end date.

Table 3 summarizes existing PPAs.

Table 3: Existing Power Purchase Agreements

	Capacity		Energy		
	Installed Capacity (MW)	Gross Continuous Unit Rating (MW)	Firm (GWh)	Average (GWh)	Agreement Expiry Date
Nalcor Energy					
Exploits:					
Grand Falls and Bishop's Falls	95.6	63.0	547	615	Renewed Annually
Star Lake	18.0	18.0	87	141	Renewed Annually
CF(L)co:					
Recapture Energy	300.0	300.0	2,362	2,362	2041
TwinCo[9] Block	225.0	225.0	1,971	1,971	2041
St. Lawrence Wind	27.0	12.0	92	105	May 2029
Fermeuse Wind	27.0	12.0	75	84	June 2029
Rattle Brook	4.0	-	13	15	October 2023
CBPP Co-Gen	15.3	8.0	67	67	January 2023
New World Dairies	0	0	-	4	1 yr after MFGS in-service
Total Power Purchases[10]	**711.9**	**638.0**	**5,217**	**5,363**	

3.2.1 Nalcor Energy

3.2.1.1 *Churchill Falls (Labrador) Corporation ("CF(L)Co")*

The majority of firm power and energy requirements on the Labrador Integrated System ("LIS") are supplied from the 5,428 MW CF(L)Co hydroelectric generating facilities in Churchill Falls

[9] Twin Falls Power Corporation ("TwinCo").
[10] Differences between total vs. addition of individual components due to rounding.

under two agreements: the Recapture Block and the Twin Falls Power Corporation ("TwinCo") Block.[11]

Recapture Energy

The Recapture Block provides Hydro with up to 300 MW from CF(L)Co for use outside the province of Quebec. The purchases are limited to 300 MW at a 90 percent load factor on a monthly basis and a maximum of 2,416 GWh of energy per year. This power and energy is physically delivered at the 230 kV bus in Churchill Falls for use in Labrador West, the Happy Valley-Goose Bay area, and in the Churchill Falls area. However, contractually, for measuring the delivered quantities for pricing purposes the deliveries are deemed to occur at the Labrador–Quebec border. The price paid is equivalent to the price paid by Hydro Québec ("HQ") to CF(L)Co for Power and Energy under their 1969 Power Contract. The agreement between Hydro and CF(L)Co has a term that expires in 2041 to coincide with the termination of the 1969 Power Contract.

TwinCo Block

The TwinCo Block of power is a firm 225 MW block of power and energy, capable of supplying 1,971 GWh per year. It is currently used to meet customer requirements in Labrador West.

Exploits

Hydro currently has a contract with the Government of Newfoundland and Labrador to operate and purchase energy from the generating facilities at Star Lake and on the Exploits River ("Exploits"). The Exploits watershed was developed in 1905 to support the development of the

[11] On May 12, 1969, Hydro-Quebec and CF(L)Co entered into a power contract for the purchase of power from the CF(L)Co plant by HQ ("the 1969 Power Contract"). Pursuant to Section 6.6 of the 1969 Power Contract, CF(L)Co has exercised its right to recapture 300 MW of power ("Recapture Energy") generated at the CF power plant. Under the terms of a PPA between Hydro and CF(L)Co ("the NLH-CF(L)Co PPA") dated March 9, 1998, and amended on April 1, 1999, Hydro is able to, and does, purchase up to 300 MW of Recapture Energy from CF(L)Co for use outside of the Province of Quebec. Under the terms of the HQ-Hydro Shareholders Agreement governing the operation of the Churchill Falls plant, CF(L)Co must make a firm 225 MW block of power and energy (the TwinCo Block) available to Hydro for distribution and use in Labrador West.

Grand Falls and Bishop's Falls generating stations. The total watershed area feeding Exploits is 10,241 square kilometers. The Exploits operations are run-of-river, meaning that production is dictated by the water available in the river at the generating facilities. For the Exploits assets, local precipitation and run off into the river system account for 50 percent of the water used annually for production. The remaining water comes from the controlled watershed, the Red Indian Lake reservoir, located 80 kilometres upstream of the Grand Falls Generating Station. The Grand Falls Generating Station has six units for a total installed capacity of 76 MW and the Bishop's Falls Generating Station has nine units for a total installed capacity of 20 MW. Hydro has the ability to dispatch the generation from the Exploits facilities, guided by the principle of overall production efficiency and by prudent system operations considerations. As the system is a run-of-river system, Hydro plans for a firm capacity of 63 MW from these assets.

3.2.2 Wind Generation

3.2.2.1 *St. Lawrence Wind Farm*

Hydro began to purchase wind energy from the St. Lawrence wind farm in October 2008 (with the commercial in-service effective May 31, 2009). The PPA with the St. Lawrence wind farm was signed with the original owners, NeWind Group Inc., in December 2006. Currently, this facility is owned by Enel Atlantic Canada Limited Partnership c/o NeWind Group Inc. The term of the PPA is 20 years from the commercial in-service date.

The St. Lawrence wind farm provides 6 MW of firm capacity. The PPA is scheduled to end in May 2029, which is the end of the estimated 20-year life span of the wind farm.

3.2.2.2 *Fermeuse Wind Farm*

Hydro began to purchase wind energy from the Fermeuse wind farm in April 2009 (with the commercial in-service effective June 30, 2009). The PPA was signed with the original owners, Vector Wind Energy Inc., in June 2007. Currently, this facility is owned by Fermeuse Wind Power Corp. The term of the PPA is 20 years from the commercial in-service date.

The Fermeuse wind farm provides 6 MW of firm capacity. The PPA is scheduled to end in June 2029, which is the end of the estimated 20-year life span of the wind farm.

3.2.2.3 *Modelling Wind Generation*

In the Resource Planning Model, wind is modelled with a fixed hourly generation profile taken from the year 2012. This year was specifically chosen as it had an average energy close to the historical average energy of wind generation. This is an appropriate approach as this model is focused on the economics of generation versus the reliability of generation. Annual maintenance and forced outages are included in the generation profile. As discussed in Volume I, Section 4.2.3.1 of this Study, the Effective Load Carrying Capability ("ELCC") study determined that the combined ELCC of the wind turbines was 22% or approximately 6 MW of firm capacity per wind farm.

3.2.3 Other Power Purchase Agreements

3.2.3.1 *Corner Brook Pulp and Paper Cogeneration*

This agreement is for the purchase of power and energy from the 15 MW cogeneration facility at CBPP's Corner Brook paper mill. The power is delivered at CBPP's 66 kV station at the mill. Purchases are made on a take and pay basis at energy only rates. The rates have multiple components reflecting the plant fixed costs, variable operating and maintenance ("O&M") costs and fuel costs. The variable O&M component changes in accordance with variances in the Consumer Price Index and the fuel component varies with CBPP's cost of fuel oil. If the facility delivers in excess of 110 GWh of energy in a calendar year the excess energy is charged at a reduced rate based on fuel and variable O&M costs only.

The CBPP Cogeneration agreement provides 8 MW of firm capacity. The agreement expires on January 30, 2023; the twentieth anniversary of the commercial in-service date.

3.2.3.2 *Rattle Brook*

This agreement is for the purchase of power and energy from the 4 MW Rattle Brook Hydroelectric Generating Facility in White Bay, Newfoundland. The power and energy is delivered at a tap in transmission line TL 253 between Jackson's Arm Tap and Coney Arm terminal stations. The purchases are made on a take and pay basis at energy only rates. The rates are adjusted seasonally with a winter rate applicable from November to March and a lower non-winter rate applicable to the remainder of the year. There are also components of the rates that escalate in accordance with changes in the Consumer Price Index. The agreement expires on the twenty-fifth anniversary of the commercial in-service date of October 23, 1998, with an option by the parties to renew for a further 25 years. Rattle Brook is not assumed to provide firm capacity.

3.3 Thermal and Gas Turbines

Existing thermal resources include Holyrood; gas turbine ("GT") facilities at Happy Valley-Goose Bay, Hardwoods, Holyrood, and Stephenville; and diesel facilities at Holyrood and on the Northern Peninsula. While in operation, the facilities are assumed to be available at rated capacity. Each unit is modelled as a generator with the respective historical average annual maintenance outage schedule factored into the generation profile. No seasonal restrictions have been placed on the thermal resources in the model. Table 4 and Table 5 provide a summary of the capability of Hydro's owned thermal generating units in the current and future systems, respectively.

Table 4: Capability of Thermal Generating Units (Current System)

Thermal Generating Units	Installed Capacity (MW)	Gross Continuous Unit Rating (MW)
Holyrood Plant		
Holyrood Unit 1	170.0	170.0
Holyrood Unit 2	170.0	170.0
Holyrood Unit 3	150.0	150.0
Total Holyrood Plant	*490.0*	*490.0*
Gas Turbine		
Happy Valley GT	25.0	25.0
Hardwoods GT	50.0	50.0
Holyrood GT	123.5	123.5
Stephenville GT	50.0	50.0
Total Gas Turbine	*248.5*	*248.5*
Diesel		
Hawkes Bay Diesel Plant	5.0	5.0
Holyrood Diesels	12.0	8.0
St. Anthony Diesel Plant	9.7	9.7
Total Diesel	**26.7**	**22.7**
Total Thermal	**765.2**	**761.2**

It is assumed that the Holyrood Thermal Generating Station ("Holyrood") and the GT facilities at Hardwoods and Stephenville will be retired in 2021. Refer to Volume II, Section 3.3 of this Study for further details on asset retirements.

Table 5: Capability of Thermal Generating Units (2022 and beyond)

Thermal Generating Units	Installed Capacity (MW)	Gross Continuous Unit Rating (MW)
Gas Turbine		
Happy Valley GT	25.0	25.0
Holyrood GT	123.5	123.5
Total Gas Turbine	*148.5*	*148.5*
Diesel		
Hawkes Bay Diesel Plant	5.0	5.0
Holyrood Diesels	12.0	8.0
St. Anthony Diesel Plant	9.7	9.7
Total Diesel	**26.7**	**22.7**
Total Thermal	**175.2**	**171.2**

3.4 External Markets

Currently, the only firm capacity export included in this Study is the Nova Scotia Block. The requirement to deliver the Nova Scotia Block begins in the year 2020 upon the in-service of the third unit at Muskrat Falls. The contractual agreement provides 0.98 TWh in equal daily quantities for 16 hours per day, 365 days year. This Study also includes delivery of the Supplemental Block[12] which commences with the delivery of the Nova Scotia Block. This agreement provides additional firm energy to Nova Scotia Power annually over a five-month time period (November to March). The Supplemental Block expires in 2025.

3.5 Capacity Assistance

Capacity assistance refers to contracted curtailable loads and emergency customer generation. Capacity assistance agreements are generally restricted in terms of frequency, duration, and annual usage. There is currently 90 MW of capacity assistance contracted from CBPP through to 2022. On November 2, 2018 Hydro applied to increase the amount of capacity assistance

[12] Supplemental Energy refers to an additional firm energy commitment to supply energy to Nova Scotia during the first five years of production at the MFGS as part of the Amended and Restated Energy and Capacity Agreement.

available under this contract to 105 MW. Hydro has also applied to continue both the Capacity Assistance and the Curtailable Load contracts previously held with Vale for the winter 2018-2019 operating season.

3.6 Transmission

The NLIS is comprised of two regions - the IIS and LIS, linked by the LIL transmission infrastructure. There are also two external areas modelled, representing the two connections to external markets via Quebec and Nova Scotia. The transfer capability of each transmission line is included in resource planning.

The NLIS regions are further divided into sub-regions (i.e., Avalon, Off-Avalon, Lab-West, Lab-East), linked by the bulk transmission network. A simplified representation of the bulk transmission system is modelled to ensure that resource options under consideration are capable of delivering electricity to meet customer requirements and that all known constraints are appropriately considered as part of the resource planning process. Figure 4 shows a visual representation of the system topology included in the resource planning process.

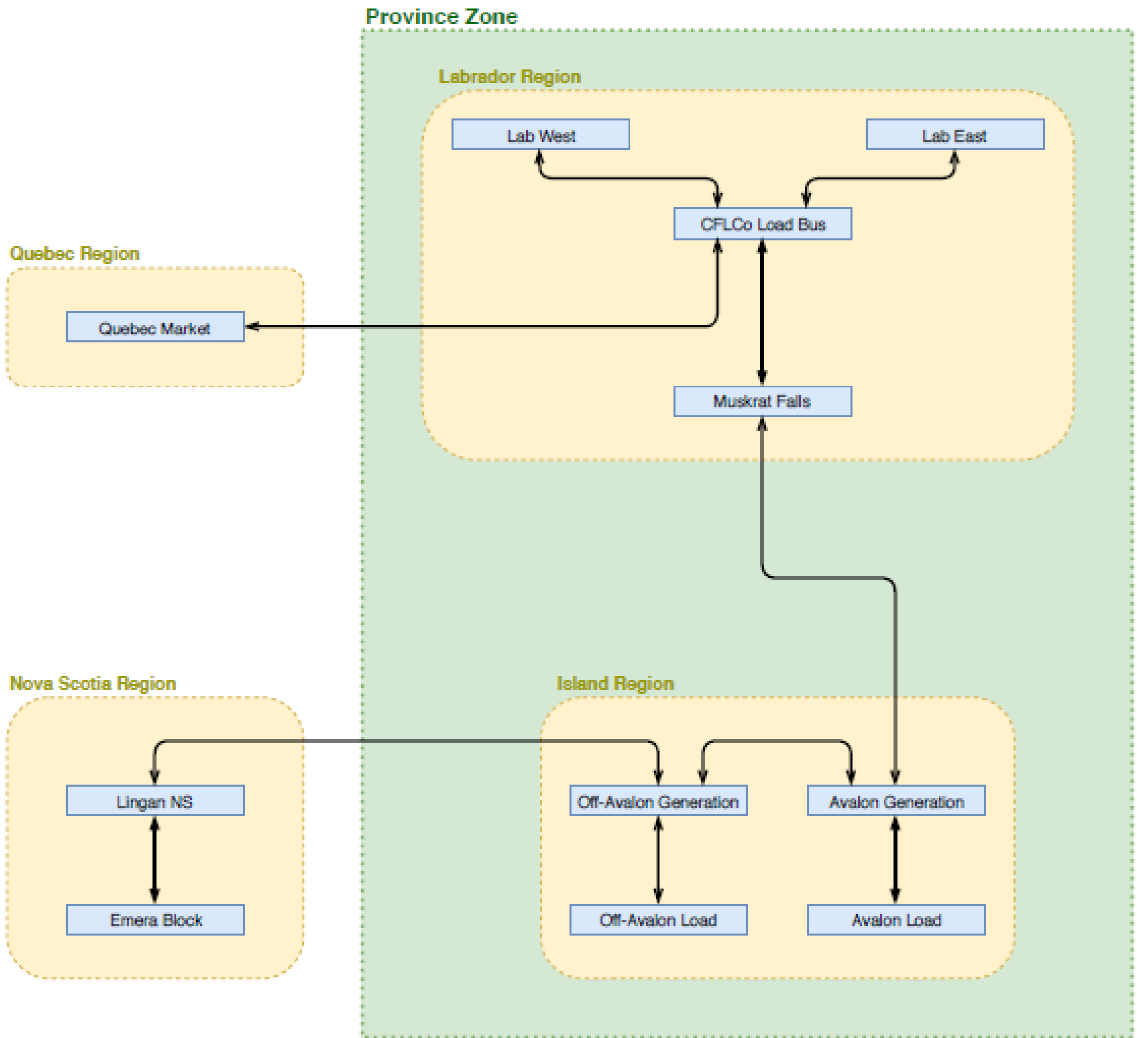


Figure 4: System Topology

4 Expansion Options under Consideration[13]

The resource planning process identifies when incremental resources are required and which resource options fulfill Hydro's mandate of least-cost reliable supply by selecting the optimum resource mix from the portfolio of available resource options. This section presents a summary of identified resource options. It includes the current portfolio of identified alternatives that

[13] Refer to Volume III, Attachment 4 "Resource Options not Under Consideration" for details on resource options not considered.

may be considered to fulfill future resource requirements. The project summaries in each of the subsections include a brief project description and project-specific potential issues and risks. Each option also includes a class 5 estimate. The estimates contained in this review were based on escalating estimates previously prepared to 2018 dollars. Hydro has since commenced external validation of all estimates. This work will be complete in early 2019 and should any modifications be required to estimates, Hydro will determine next steps and any required adjustments will be made as part of the annual planning process. For more detailed descriptions of the identified alternatives, please refer to the project-specific attachment. The Study considered a range of alternative resource options and conventional generation options. A summary of resource options considered is included in Table 6.

Table 6: Resource Options Considered

Wind Generation
Solar Generation
Battery Storage Technology
Capacity Assistance
Rate Design and Customer Demand Management
Market Purchases
Hydroelectric Generation (new facilities, additional units at existing facilities)
Thermal Generation (simple cycle gas turbines, combined cycle combustion turbines)

4.1 Wind Generation[14]

Both Newfoundland and Labrador are noted to have strong wind regimes, leading to the potential for development of wind generation projects. Such projects could feasibly be executed by interconnecting a relatively large farm at transmission voltage level, or by opting for a distribution-connected option. As such, two types of wind generation projects were

[14] Refer to Volume III, Attachment 5“NL Hydro Wind Generation Alternative,” New Colliers Ltd, November 3, 2018, for further details.

considered: a single 100.8 MW installation and multiple instances of 12.6 MW installations. As there are many sites that could be geographically suitable for wind project development in both Newfoundland and Labrador, no specific location has been identified for either alternative. The 100.8 MW project would consist of 24, 4.2 MW turbines and the 12.6 MW project would consist of three, 4.2 MW turbines. It is estimated that this would provide a gross per-turbine yield of approximately 18 GWh per year at a location with a yearly average wind speed of approximately 8.5 metres per second.

Depending on the alternative selected, the project would require up to two overhead/underground collection systems with the necessary communications, protection and control; construction of crane pads and wind turbine foundations; erection of the wind turbines tower sections, nacelles and blades; installation and wiring of the substation electrical equipment at the distribution point of interconnection.

The 100.8 MW alternative would require interconnection to a 138 kV transmission line, whereas the 12.6 MW alternative would require interconnection to a 25 kV transmission line.

Overall, wind generation provides emissions-free energy and impacts a relatively small footprint during the construction phase. Choosing a proper location can reduce negative impacts such as noise emissions, visual impacts, bird and bat mortality, and disturbance of wetland or other key habitat.

The class 5 estimate was provided by an external consultant and is based on experience with industry-normal costs from across Canada in conjunction with Newfoundland and Labrador's specific development and construction environment. Land lease costs were not included in the estimate.

The wind projects will require 24 months of site-specific environmental monitoring to adequately define the resource. Project development, environmental review and feasibility studies for attractive sites are typically initiated concurrent with the resource study and are finalized shortly after completing the resource assessment. The final design and construction for a wind farm could be completed over an additional 12 to 24 months, depending on the project profile selected. The overall project schedule is approximately 36 to 48 months from application to the Board to project in-service.

4.2 Solar Generation[15]

Two alternatives for solar generation were considered, based on installation of a 9.81 MWdc/ 7.5 MWac distribution-connected solar farms. Based on preliminary screening, Gander and Labrador City were suggested as potential site locations by an external consultant. Each location has large industrial loads that minimize interconnection costs. Each location has above-average solar regimes compared to the rest of the province with good availability of land.

This alternative requires the installation of driven piles, steel mounting structures, a low voltage collection system, and construction of the solar array pad. The construction of the supporting structures and piling would occur in advance of the solar panel delivery. The structure arrangement consists of 112 panels; each measuring 2 by 1 metres.

The solar generation alternative would require being within 500 metres of a three phase distribution line with a capacity of 8 MW in order to interconnect with the system.

The class 5 estimate was provided by an external consultant and is based on experience with industry-normal costs from across Canada in conjunction with Newfoundland and Labrador's specific development and construction environment.

[15] Refer to Volume III, Attachment 6 "NL Hydro Solar Generation Alternative," New Colliers ltd., November 2, 2018 for further details.

Solar panels produce emissions-free energy over the operational life of the project and a relatively low impact during the construction phase. Choosing a proper location in the development phase can reduce negative environmental impacts such as visual impacts, including glare, bird mortality, and disturbance of wetland or other key habitat.

The solar power industry is still maturing in Canada and is relatively new in Newfoundland and Labrador. This alternative does present risk in Newfoundland and Labrador due to adequacy of solar resource (particularly given reduced daylight hours experienced during winter peak), access to injection points on the grid that can accommodate generation with modest system upgrades and that are also close to strong solar resource project locations, and design and resource constraints imposed by heavy snow load regimes.

4.3 Batteries[16]

A 100 MW lithium ion battery storage solution to support up to two hours of power shortfall in contingency situations was considered. The battery system has round-trip efficiency[17] of more than 85 percent and can be situated at optimal grid interconnection points to provide fast response to grid contingency events.

Each battery is enclosed in 14 metre long containerized modules, each with individual capacities of 2 MW. The Battery Management System, Power Management System, and Power Conditioning System are supplied in separate 14 metre long containers that have the capacity to support two, 2 MW battery container modules. Construction would include the installation of a fenced battery array pad, installation of reinforced concrete pads for container mounting, and an underground low voltage collection system to allow for terminations at containers and ac equipment.

[16] Refer to Volume III, Attachment 7 “NL Hydro Battery Storage Alternative,” New Colliers Ltd., November 3, 2018 for further details.
[17] Round-trip efficiency is a calculation of the ratio of energy put in (in MWh) to energy retrieved from storage (in MWh).

The battery storage system requires interconnection to an existing major substation such as Holyrood, Western Avalon, or Oxen Pond, which all have 66/69 kV buses. Alternatively, interconnection to the 25 kV or 35 kV bus of an existing or new wind project may provide for the most economical interconnection option.

Battery storage technologies provide the means to increase the proportion of renewable energy on the grid and impact a relatively small footprint during the construction and operational phase. Choosing a proper location can reduce negative impacts such as disturbance of wetlands or other key habitats during construction and operation. An additional environmental risk is the containment and recycling of heavy metals and electrolyte materials. The class 5 estimate was provided by an external consultant and is based on experience with industry-normal costs from across Canada in conjunction with Newfoundland and Labrador's specific development and construction environment. Land lease costs were not included in the estimate.

The battery project will require 24 months to conduct an environmental assessment based on a preliminary battery system layout. A system impact study in Year One followed by a facility study in Year Two to assess the impact, cost, and system modifications associated with interconnecting the new battery storage generating facility are required. All project construction activities can be completed in approximately one year. The overall project schedule is approximately 36 months following application to the Board to the in-service date.

Providing frequency regulation and voltage support in non-contingency situations may reduce the reserve capacity of the battery system. Also, the lifetime of lithium ion batteries may also be reduced if the batteries are kept at 100 percent charge for extended periods of time. Before such a solution could be integrated into the NLIS, a detailed study would be required to determine the control balance.

4.4 Capacity Assistance and Curtailable Load

In the Resource Planning Model, it is assumed that a generic 100 MW of capacity assistance in 20 MW incremental blocks will be available for purchase, similar to that currently contracted in the existing system. It is assumed that current curtailable load pricing will be scaled based on an economic escalator which will form a basis of estimate for future curtailable load contracts.

4.5 Rate Structures and Customer Demand Management

While additional supply can be acquired to meet increased customer requirements, rate design and Conservation and Demand Management ("CDM") activities can also be undertaken to promote a reduction in customer demand and/or energy requirements.

4.5.1 Pricing Strategies

There are a number of pricing strategies that utilities can apply to send price signals to customers which communicate the cost of serving load at specific times and, ultimately, assist with demand management. Hydro has begun to undertake preliminary research into pricing strategies and technologies employed in other jurisdictions to help manage customer demand.

Two pricing strategy alternatives, Time of Use ("TOU") rates and Critical Peak Pricing ("CPP"), warrant further exploration to determine whether application of such can be beneficial and cost-effective in managing Hydro's peak demand periods. Both TOU and CPP require smart meters which can be used for several different billing alternatives for both the utility's and customer's benefit. The requirement and cost of providing smart metering infrastructure is an important factor in considering rate design initiatives.

Pricing strategy alternatives that warrant further exploration:

- **Time of Use Rates**
- **Critical Peak Pricing**

4.5.1.1 ***Time of Use Rates***

Outside of Hydro's critical peak hours in the winter, Hydro also has seasonal and daily peaks. In general, peak daily demand occurs during the morning (approximately 7:00 a.m.to 9:00 a.m.) and in the evening (approximately 4:00 p.m. to 7:00 p.m.) on weekdays, but is generally lower overnight and on weekends. TOU pricing varies throughout the day based on the hourly marginal cost of supply, with the highest rates during peak hours and lowest rates during off-peak hours.

Ontario has a broad implementation of TOU rates and Nova Scotia offers TOU service to select customers.[18] British Columbia Hydro ("BC Hydro"), New Brunswick Power, and Newfoundland Power have undertaken research on TOU pricing and smart meters.

<u>New Brunswick</u>

In October 2017, New Brunswick Power applied for approval for a capital project having a total capital cost in excess of $90 million for the installation of smart meters to enable TOU rates. This application was ultimately denied as no positive business case was established in New Brunswick Power's evidence.[19]

<u>Ontario</u>

Ontario's demand response from residential customers as a result of TOU rates has been lower than originally forecast. A 2016 study by the Environmental Commissioner of Ontario stated that TOU pricing has resulted in a 0.7 percent reduction in peak demand, which is nearly six times less than originally forecast. The study noted that the peak demand reduction would likely be greater if the differential between peak and off-peak prices were greater. Ontario's current ratio of peak to off-peak pricing is approximately 2:1.

[18] Nova Scotia Power limits TOU rates to those customers who have an electric-based space heating system that has the capacity to store heat with appropriate timing and controls in place and approved by Nova Scotia Power.
[19] Decision Matter No. 375 dated July 20, 2018.

British Columbia

In 2006, BC Hydro launched a Conservation Research Initiative to test TOU rates and smart meters to help determine how adjusting the price of electricity at different times of day influences electricity use by residential customers. Overall energy consumption of participants was reduced by 7.6 percent, with energy use during peak hours being reduced by 11.5 percent. Key to the success of BC Hydro's TOU study appears to be an approximate 4:1 price ratio between peak and off-peak pricing; a price differential of this magnitude provides customers with a sufficient price signal to elicit a response.[20] BC Hydro does not currently offer TOU rates to residential customers.

Newfoundland and Labrador

In 2011, Newfoundland Power undertook a TOU study with approximately 240 participants. The results of this study were less favourable than those experienced by BC Hydro, with electric participants realizing a reduction of 5 percent in their morning peak and no material difference for the evening peak; however, the price ratio of peak to off-peak rates in Newfoundland Power's study was 1.5:1.

2018 Digital Engagement Study showed respondents have a clear interest in learning more about TOU rates

Through Hydro's digital engagement initiative, feedback was collected on TOU rates. Results from the digital engagement initiative indicate that respondents have an interest in TOU rates, with 63 percent of responses showing a high level of interest.[21] Further, respondents identifying as residing on the Avalon Peninsula, as well as those who identified as customers of Newfoundland

[20] BC Hydro employed five experimental TOU rates with off-peak prices ranging from 4.50 cents per kWh to 6.33 cents per kWh and peak prices ranging from 15.00 cents per kWh to 28.00 cents per kWh.
[21] Respondents were asked to gauge their interest in signing up for time of use rates on a scale of 1 to 10. Sixty-three percent (63%) of responses scored between 7 and 10.

Power were more likely to show interest in TOU rates at 67 percent and 65 percent, respectively.

4.5.1.2 *TOU Rates Conclusion*

Based on Hydro's digital engagement initiative, customers of electricity in Newfoundland and Labrador have a high level of interest in alternative rate options.

Newfoundland Power supplies over 90 percent of domestic and general service customers within the IIS and has the primary responsibility for the development of retail pricing for this portion of the NLIS, excluding large industrial customers.[22] The most recent comprehensive rate design review conducted in Newfoundland and Labrador was by Newfoundland Power from 2008 to 2011. It resulted in the introduction of an optional residential seasonal rate, and a time of day rate study. The time of day rate study was conducted to gather feedback from customers in relation to retail rates that would be different during peak and off-peak periods.

Hydro has had discussions with Newfoundland Power concerning the evaluation of rate options for the IIS post-Muskrat Falls. Hydro has been advised that Newfoundland Power is expecting to begin a rate design evaluation as soon as sufficient information on the post-Muskrat Falls system becomes available. Hydro updated its marginal cost study for the IIS on November 15, 2018. This information will be useful to the required rate design review.

As the majority of customers that would be affected by TOU rates are those of Newfoundland Power, Hydro believes an updated study into the feasibility of TOU rates, in conjunction with Newfoundland Power, is warranted. While other utilities' experiences indicate there could be potential for TOU rates on the IIS, such systems are costly and a positive business case and detailed cost benefit analysis would need to exist to warrant such an investment.

[22] Hydro's customers on the IIS are offered the same rates that are available to Newfoundland Power's customers.

In conjunction with this review, Hydro will need to study whether TOU rates are justified and appropriate for its Island Industrial Customers, and its rural customers on the LIS.

4.5.1.3 *Critical Peak Pricing*

CPP generally refers to a voluntary rate program where customers are paid to curtail their electricity consumption at the request of the utility during periods when available capacity is limited. These requests are typically made on a day- or hour-ahead basis and have a maximum number of hours that the utility can request. Customers who successfully curtail during the requested timeframe receive a billing credit reflecting the avoided capacity cost of their curtailment.

Hydro's peak demand occurs during the winter[23] when electric heating loads are highest. During Hydro's coldest days, the peak demand can be substantially higher than the average winter demand. To meet requirements on the days when demand is highest, Hydro has to design its system so it has adequate infrastructure to meet this peak demand, even if it is only required on several occasions through the year. Developing CPP which reflects the cost of capacity during critical peak times can send appropriate price signals to customers to incent them to shift or reduce their load requirements and, in turn, reduce the peak demands.

CPP is not uncommon in jurisdictions in the United States. In Canada, HQ through its most recent rate application,[24] proposed a critical peak pricing program which has a price signal of \$50 per kW for a maximum of 100 critical peak hours, beginning December 2019.[25]

[23] December 1 – March 31.
[24] Filed with the Regie de l'Energie in July 2018.
[25] The program would provide subscribed customers with a credit or charge of \$0.50 per kWh for energy conserved or used during critical times. HQ chose the rate on the basis that it considered the rate to be sufficient incentive and contrast with its typical pricing. HQ chose this option following consultation with its customers, which determined that they would be incented to participate if they were able to achieve savings of between 10% and 20% on their electricity bill. This program is scheduled to begin this coming winter.

<u>CPP Conclusion</u>

In addition to the rate design study to be undertaken in conjunction with Newfoundland Power, Hydro plans to monitor the results of HQ's CPP program. Hydro believes that HQ's results will be useful in evaluating the costs and benefits of CPP as part of the next rate design review to be conducted by Newfoundland Power.

4.5.2 CDM Potential Study

Hydro and Newfoundland Power have offered customer energy conservation programs on a joint and coordinated basis under the takeCHARGE brand since 2009. These programs provide a range of information and financial supports to help customers manage energy usage.

CDM activities can promote a reduction in either customer energy or demand requirements

Hydro and Newfoundland Power ("the Utilities") are conducting a CDM Potential Study commencing in late 2018. The objectives of the CDM Potential Study are to identify the achievable, cost-effective electric energy and demand management measures to reduce or shift peak demand, outline general parameters for program development, and quantify achievable savings potential by sector and end use in the province.

Similar to the 2007 and 2015 CDM Potential Studies, the information in this Study will be critical in assessing takeCHARGE programs that are equally responsive to customer expectations. It will also support the Utilities' efforts to be responsible stewards of electrical energy resources and ensure that takeCHARGE program offerings support Hydro's mandate to provide least-cost, reliable electricity service. The 2018 CDM Potential Study will provide a resource to support the Utilities in developing a comprehensive vision of the province's future energy service needs.

Historically, the Utilities have focused takeCHARGE programs on energy efficiency to save electrical energy based on an economic analysis driven by the cost of fuel consumption

Holyrood. However, the 2018 CDM Potential Study will have a highlighted focus on demand management technologies and their potential to reduce or shift peak demand in order to limit the required investment in capacity additions for the IIS.

Upon completion of the 2019 CDM Potential Study, a new multi-year plan will be developed that will use the outcomes from the 2018 CDM Potential Study to plan and design energy efficiency and demand management programs.

4.6 Market Purchases

For the study period, Nalcor Energy Marketing ("NEM") provided Hydro with information regarding the potential for capacity and energy purchases from various counterparties using the interties.[26] This information was based on publicly available information (e.g., fuel costs, transmission costs, excess available capacity, and capacity costs) for neighbouring jurisdictions. In the event that Hydro is forecasting a capacity deficit at any time in the future, NEM will conduct a detailed market sounding for capacity and/or energy as required.

4.7 New Hydroelectric Generation Developments

This section describes additional on-island hydraulic resources that have the potential for development. Any hydroelectric development and associated transmission line construction is subject to the Provincial Environmental Protection Act ("EPA") and the Environmental Assessment Regulations ("ERA"). Generally, project in-service can require up to 48 months from the application to the Board to the in-service date, with construction lasting approximately 36 months. Table 7 provides a summary of the potential developments.

[26] An intertie refers to a system of transmission lines permitting a flow of energy between major power systems.

Table 7: Summary of Projects: New Hydroelectric Generation Developments

Facility	Capacity (MW)	Average Energy (GWh)	Firm Energy (GWh)	Capital Cost ($ million)	Capital Cost ($million/MW)
Island Pond	36	186	175	405	11.2
Portland Creek	23	142	125	262	11.4
Round Pond	18	139	129	248	13.8
Red Indian Falls	42	268	228	393	9.4
Badger Chute	24	154	131	249	10.4
Star Lake	TBD	TBD	TBD	TBD	TBD

4.7.1 Island Pond Hydroelectric Development [27]

Island Pond is a proposed 36 MW hydroelectric project located on the North Salmon River, within the watershed of the existing Bay d'Espoir development. The project would utilize approximately 25 metres of net head between the existing Meelpaeg Reservoir and Crooked Lake to produce an annual firm and average energy capability of 175 GWh and 186 GWh, respectively. Electricity would be produced by one 36 MW turbine and generator assembly. The project requires the construction of 18 kilometres of transmission and a new terminal station.

[27] For further details on Island Pond Hydroelectric Development option, refer to Volume III, Attachment 8 "Island Pond Hydroelectric Development." Figure included from "Studies for Island Pond Hydroelectric Project," SNC Lavalin Inc., 2006

The cost estimate, for the construction of the Island Pond Hydroelectric Generating Station was derived from the report "Studies for Island Pond Hydroelectric Project," SNC Lavalin Inc., 2006. The estimate was later updated by SNC Lavalin Inc. in 2012. The current class 5 estimate was derived by escalating the 2012 costs to present-day dollars and compared to current costs generated for projects of similar size and complexity to ensure costs were factored proportionately.

4.7.2 Portland Creek Hydroelectric Development[28]

Portland Creek is a proposed 23 MW hydroelectric project located on Main Port Brook, near Daniel's Harbour, on the west side of the Great Northern Peninsula. The project would utilize approximately 395 metres of net head between the head pond and outlet of Main Port Brook to produce an annual firm and average energy capability of 125 GWh and 142 GWh, respectively. Construction of a 25.5 kilometre long, 66 kV transmission line is required to the existing Peter's Barren Terminal Station would be required to interconnect the project to the system.

[28] For further details on Portland Creek hydroelectric development option, see Volume III, Attachment 9 "Portland Creek Hydroelectric Development." Source: Conceptual sketch of Portland Creek Hydroelectric Development, Hydro.

The cost estimate, for the construction of the Portland Creek Hydroelectric Generating Station was derived from the "Feasibility Study for Portland Creek Hydroelectric Project" report, completed by SNC Lavalin Inc. in 2007. The estimate was later updated by SNC Lavalin Inc. in 2012. The current class 5 estimate was derived by escalating the 2012 costs to present day dollars and compared to current costs generated for projects of similar size and complexity to ensure costs were factored proportionately.

4.7.3 Round Pond Hydroelectric Development[29]

Round Pond is a proposed 18 MW hydroelectric project located within the watershed of the existing Bay d'Espoir development. The project would utilize the available net head between the existing Godaleich Pond and Long Pond Reservoir to produce an annual firm and average energy capability of 129 GWh and 139 GWh, respectively. Electricity would be produced by a single, 18 MW generating unit. To complete the interconnection with the existing system, a 44 kilometer long, 69 kV transmission line is required to connect the existing Bay d'Espoir Terminal Station No. 2.

The cost estimate for the construction of the Round Pond Hydroelectric Generating Station was derived from the "Round Pond Feasibility Study Report," completed by Shawinigan Newfoundland Limited in 1988. The 1988 dollars were escalated to present-day dollars and compared to current costs generated for projects of similar size and complexity to ensure costs were factored proportionately.

[29] For further details on Round Pond Hydroelectric Development option, see Volume III, Attachment 10 "Round Pond Hydroelectric Development."

4.7.4 Exploits River Hydroelectric Development[30]

Any potential developments on the Exploits River and surrounding watershed will face significant environmental challenges and will be subject to the EPA and the ERA. The most substantial environmental impact is anticipated to be on the fish habitat, affected during both the construction and operation of the plant. Requirements for fish passage both upstream and downstream of the development would have to be satisfied, as well as a thorough archeological assessment of the affected areas.

Cost estimates for both identified projects were derived from a study in 1979 by an external consultant. The study was updated in 2002 and again in 2005 by external consultants. The 2005 dollars were escalated to present day dollars and compared to current costs generated for projects of similar size and complexity to ensure costs were factored proportionately as reflected in the class 5 estimates.

4.7.4.1 *Red Indian Falls Development*

Red Indian Falls is a proposed 42 MW hydroelectric project located on the Exploit's River System, located approximately 20 kilometres upstream of the Town of Badger. The project would utilize approximately 22.9 metres of net head to produce an annual firm and average energy capability of 228 GWh and 268 GWh, respectively. Electricity would be produced by the use of two turbines.

[30] For further details on Exploits River hydroelectric development option, see Volume III, Attachment 11 "Exploits River Hydroelectric Generation Expansion."

The Red Indian Falls Development would interconnect to the System via a 50 kilometre, 66 kV transmission line extending from the new generating station switchyard into the existing Buchan's Terminal Station.

4.7.4.2 *Badger Chute Development*

Badger Chute is a proposed 24 MW hydroelectric project located on the Exploit's River System, located approximately 25 kilometres upstream of Goodyear's Dam and 7 kilometres downstream of the Town of Badger. The project would utilize approximately 14.6 metres of natural net head to produce an annual firm and average energy capability of 131 GWh and 154 GWh, respectively. Electricity would be produced by the use of three vertical turbines.

The Badger Chute Development would interconnect to the system via a 20 kilometre transmission line into the Red Indian Falls switchyard.

Previous studies indicate that the development of the Badger Chute has the potential to increase ice formation and elevate the risk of flooding for the Town of Badger. However, it is believed that the construction of a generating facility at Red Indian Falls would reduce, if not eliminate, the flooding risk in the town. Therefore, if the Badger Chute development were to be pursued, it should be completed in conjunction with, or following, the completion of Red Indian Falls.

The cost estimate for the construction of Badger Chute hydroelectric generation alternative was derived from a study in 1979 by an external consultant. The study, including costs, was updated in 2002 and again in 2005 by external consultants. The 2005 dollars were escalated to present day dollars and compared to current costs generated for projects of similar size and complexity to ensure costs were factored proportionately as reflected in the class 5 estimate.

4.7.4.3 *Star Lake Unit 2*

The existing Star Lake Hydroelectric Generating Plant was constructed in 1998. The plant takes water from Star Lake and discharges it into Red Indian Lake. The plant has a single turbine with a rated capacity of 18.8 MW under maximum head conditions. There is a 635 metre dam comprised of earth filled west and east embankments with a Spillway Overflow and Intake Structure. Nalcor Energy has been operating the Star Lake Station on behalf of the Province since 2008.

It may be possible to install a second unit at Star Lake. The initial feasibility study conducted in 1982 identified the opportunity to install a 46 MW unit with a 60 percent capacity factor. This is significantly higher than the unit that was eventually installed in 1998. Additional study work would need to be completed to determine the feasibility of adding another unit to the plant.

4.8 Additional Generation at Existing Hydroelectric Generation Facilities

Table 8 provides a summary of characteristics and costing for development options at existing hydroelectric generation facilities. Any hydroelectric development and associated transmission line construction is subject to the Provincial EPA and the ERA. For both Bay d'Espoir Unit 8 and Cat Arm Unit 3, less environmental impacts are expected compared to a new hydropower facility, as the expanded hydropower facility will be integrated into the existing facilities operation with limited changes to the actual operations.

Table 8: Summary of Projects – Additional Generation at Existing Hydroelectric Generation Facilities

Facility	Capacity (MW)	Energy (GWh)	Capital Cost ($ million)	Capital Cost ($million/MW)
Bay d'Espoir Unit 8	154	N/A	373	2.4
Cat Arm Unit 3	68	N/A	725	10.7

4.8.1 Bay d'Espoir Hydroelectric Generating Unit 8 [31]

Bay d'Espoir Unit 8 is a proposed 154 MW unit located in Powerhouse 2 next to existing Unit 7. The rock excavation for the second unit and downstream portion of the draft tube was constructed in 1977 when Powerhouse 1 was commissioned. This project would provide capacity to the system. As this project would share the existing annual water supply from the existing watershed, there is no direct increased energy production associated with this project.

Bay d'Espoir Unit 8 would interconnect to the System via construction of a 1.5 kilometre 230 kV line from the Unit 8 step-up transformer to Bay d'Espoir Terminal Station No 2.

A class 3 capital cost estimate was developed by SNC Lavalin Inc. The criteria, assumptions and methodology that went into developing the estimate can be found in Volume III, Attachment 12.

[31] For further details on Bay d'Espoir Unit 8 Hydroelectric expansion option, see Volume III, Attachment 12 "Bay d'Espoir Hydro Generating Unit 8."

4.8.2 Cat Arm Hydroelectric Generating Unit 3 [32]

Cat Arm Unit 3 would increase the generating capacity of the existing Cat Arm facility by installing a third, 68.2 MW generating unit. While there is no direct increased energy production associated with this project, there could likely be incremental energy production associated with minimizing spill energy.

The project would consist of a newly constructed extension to the south side of the existing powerhouse; a permanent access road including a bridge across the tailrace to maintain access to the transformer yard; construction of a penstock; and new generating Unit 3.

The existing Cat Arm Generating Station is connected to the system via a single, 230 kV transmission line, TL 247/TL 248, to Deer Lake and Massey Drive. The addition of the third generating unit will require a second, 230 kV transmission line to complete the interconnection. However, delivering the capacity to Deer Lake may not be the appropriate point of interconnection for the new transmission line given the load centre is on the Avalon Peninsula. Therefore, a new 230 kV station is proposed near the existing 69 kV Hampden Tap Station. From this point, a new 230 kV line would be constructed eastward towards the load centre. Routing of this line would parallel the Labrador Island HVdc line from the new station location to the HVdc Birchy Lake crossing to the Buchans Terminal Station. Subsequently, a line length of 120 kilometres has been assumed for this analysis.

The original cost estimate was prepared by an external consultant in 1985. The current class 5 estimate was derived by escalating the 1985 costs to present-day dollars and compared to current costs generated for projects of similar size and complexity to ensure costs were factored proportionately. Costs for the construction of the new 230 kV transmission line and associated terminal station infrastructure were added as they were not included in the original estimate.

[32] For further details on Cat Arm Unit 3 expansion option, see Volume III, Attachment 13 "Addition of a Third Generating Unit – Cat Arm."

4.9 Simple-Cycle Gas Turbine[33]

Four GT plant alternatives have been considered. These nominal 66 MW (58.5 MW net), simple-cycle GTs would be located either adjacent to the existing unit at the Holyrood site or at greenfield locations. GTs considered are light oil-fired and, given the unit efficiency, are primarily intended for peaking and voltage support functions. The option considered includes fuel storage capacity to run continuously for a minimum of five days. While these units are considered to support capacity-driven requirements, each is capable of providing approximately 460 GWh of firm energy capability annually. Table 9 provides a summary of the GT alternatives considered.

Table 9: Gas Turbine Alternatives

Type	Number of Units	Net Capacity (MW)	Capital Cost ($ million)
Simple Cycle Plant	1	58.5	169
Simple Cycle Plant	2	117	298
Simple Cycle Plant	4	234	664

A preliminary analysis of the transmission requirements and associated single line diagrams were prepared for the purpose of cost estimates for each GT plant alternative.

Environmental considerations for the facilities contemplated have been analyzed, including required emissions control, plant location, and local traffic impact, among other things.

A class 5 capital cost estimate was derived for these units, including include cost of transmission system requirements, operation and maintenance costs, and land price for greenfield sites.

The overall project schedule is estimated to take between 24 to 36 months from the application to the Board to the in-service date.

[33] For further details on GT options considered, please refer to Volume III, Attachment 14 “Gas Turbine Alternatives.”

4.10 Combined-Cycle Combustion Turbine[34]

The combined-cycle facility, also known as a combined-cycle combustion turbine ("CCCT") facility, consists of a combustion turbine fired on light oil, a heat recovery steam generator, and a steam turbine generator.

An estimate has been prepared for a proposed combined-cycle plant to be located at Holyrood to take advantage of the operational and capital cost savings associated with sharing existing facilities. The plant size considered is a 170 MW (net) CCCT facility with an annual firm energy capability estimated at 1,330 GWh.

Environmental considerations for the facility have been analyzed and include emissions control, location of plant, and impact of traffic.

A class 5 capital cost estimate for these units was prepared; including includes cost of transmission system requirements, operation and maintenance costs, and land price for greenfield sites.

The overall project schedule is estimated to take approximately 36 months from the application to the Board to the in-service date.

5 Load Forecasts

The purpose of load forecasting is to project electric power demand and energy requirements through future periods. This is a key input to the resource planning process, which ensures sufficient resources are available consistent with applied reliability standards. The load forecast is segmented by the IIS and LIS, rural isolated systems, as well as by utility load (i.e., domestic and general service loads of Newfoundland Power and Hydro) and industrial load (i.e., larger

[34] For further details on CCCTs, see Volume III, Attachment 12 "Gas Turbine Alternatives."

direct customers of Hydro such as CBPP, North Atlantic Refining Ltd, Vale, and Iron Ore Company of Canada). The load forecast process entails translating a long-term economic and energy price forecast for the province into corresponding electric demand and energy requirements for the electric power systems.

The load forecast is segmented as follows:

- **IIS**
- **LIS**
- **Rural Isolated Systems**
- **Utility Load**
- **Industrial Load**

The resource planning process considers a range of potential forecast scenarios, rather than a single forecast. This allows for evaluation of the sensitivity of results to differing economic conditions. For this planning exercise, a range of forecasts were developed independently for the Island and Labrador, which when combined with evaluation of both the P50 and the P90 conditions for the IIS as discrete scenarios, resulted in the evaluation of 24 discrete scenarios.[35] A visualization of the scenarios considered is presented in Figure 5.

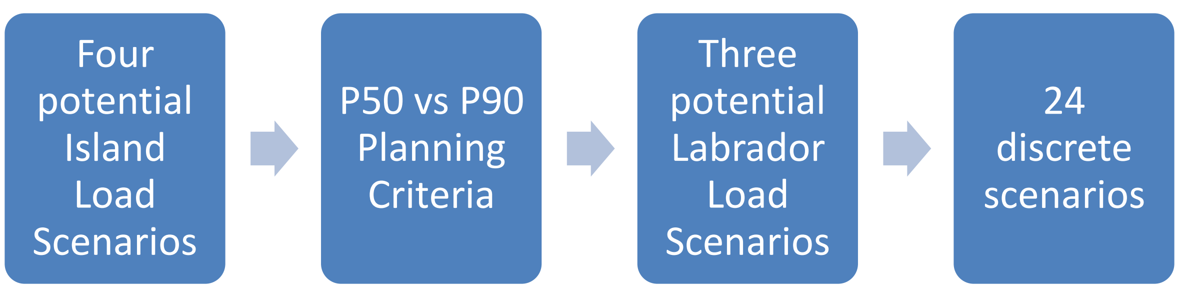


Figure 5: Modelled Scenarios

[35] A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50 percent of the time and above 50 percent of the time (i.e., the average forecast). A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90 percent of the time and above 10 percent of the time.

5.1 Economic Variability based on Provincial Economic Overview

Newfoundland and Labrador is experiencing a transitionary period, as major projects reach completion and new developments are waiting to be realized.

In 2017, Newfoundland and Labrador’s economy continued to adjust, with major projects transitioning from development to production phases (e.g., ExxonMobil’s Hebron Project and Vale’s Long Harbour Processing Plant) resulting in lower levels of investment and employment. While exports of goods and services increased by 1.6 percent in real terms over 2016, overall economic activity decreased, with real gross domestic product (“GDP”) decreasing by 3.4 percent from 2016. Employment levels have also decreased by 3.7 percent from 2016, marking a four-year decline in employment.

The seafood sector remains a significant contributor to the provincial economy, with the value of the fishery increasing in 2017. While the aquaculture industry experienced decreased volumes and value in 2017, increased interest in this area of business is expected to expand the industry.

The mining sector had significant milestones in 2017, including the purchase of Wabush Mine’s assets by Tacora Resources, and the first full year of production at the Long Harbour Nickel Processing Plant. Iron Ore Company of Canada also announced it would proceed with the Wabush 3 project, and an overall mineral exploration and development activity in the province experienced its first year-over-year increase since 2012.

Over the medium term (i.e., one to five years), adjusted real GDP is forecast to decline, being partially offset with increases in exports, driven by new energy and mining projects. Capital investment is expected to decline, due to the completion and final stages of development for major projects. According to current provincial economic reports by many Canadian financial institutions, it is anticipated that weakening capital investment trends, in addition to the provincial government's expenditure reduction plan, will cause further attrition in employment, and the housing market to remain soft. [36,37]

With the Provincial Government's fiscal situation remaining relatively challenging and an overall weak economic environment, the underlying local market conditions for electric power operations suggest moderate decline before possible rebounding by the end of the medium-term. Table 10 provides the provincial economic assumptions, as forecast by the Department of Finance, Government of Newfoundland and Labrador. [38] These inputs form the basis of Hydro's load forecast models.

The underlying local market conditions for electric power operations suggest moderate decline before possible rebounding through the medium-term.

Table 10: Provincial Economic Indicators – 2018 Planning Load Forecast

		2017-2023	2017-2029
Adjusted Real GDP at Market Prices[39]	Case I, II, III	-1.8%	-0.3%
(% Per Year)	Case IV	-1.7%	0.4%
Real Disposable Income	Case I, II, III	-0.6%	-0.01%
(% Per Year)	Case IV	-0.5%	0.5%
Average Housing Starts	Case I, II, III	1262	1213
(Number Per Year)	Case IV	1266	1268
End of Period Population	Case I, II, III	514	513
(000s)	Case IV	514	516

[36] "Provincial Outlook," RBC, June 2018, <http://www.rbc.com/economics/economic-reports/pdf/provincial-forecasts/nl.pdf>
[37] "Provincial Economic Forecast," TD Economics, September 18, 2018 <https://economics.td.com/domains/economics.td.com/documents/reports/pef/ProvincialEconomicForecast_Sep2018.pdf >
[38] "Budget 2018, The Economy, Building Our Future," Government of Newfoundland and Labrador, <https://economics.gov.nl.ca/E2018/TheEconomy2018.pdf>
[39] Adjusted GDP excludes income that will be earned by the non-resident owners of provincial resource developments to better reflect growth in economic activity that generates income for local residents.

Economic forecasts and indicators including fuel price, weighted average cost of capital ("WACC"), and escalation rates were used consistent with Nalcor's Investment Evaluation Corporate Assumptions from September 2018.

5.2 Considered Potential Island Load Scenarios

Total Island load is the summation of interconnected utility load, industrial customer loads, as well as bulk transmission and distribution power and energy losses incurred serving the customer load requirements on the system.

Four scenario cases were developed for the IIS based on consideration of a range of potential retail electricity rates.

Four scenario cases were developed for the IIS based on a range of potential retail electricity rates

Table 11 presents the forecast scenarios for utility load growth on the IIS that includes the load requirements for Newfoundland Power and Hydro's rural customers. Of note is the range of load change possibilities for the IIS, which is driven by the provincial economic outlook and the uncertainty of electricity rates. Cases I, II, and III are representative of the base provincial economic forecast with varying electricity price forecasts.[40] Case IV is representative of the high provincial economic forecast with a low electricity rate forecast. Through the medium term, the economic growth expectations for the province coupled with the alternate rate outlooks, all indicate declining utility load requirements with the degree of declining load requirements primarily dependent on the level

[40] The low growth and reduction in customer loads indicated by Cases I, II, and III are associated with alternate electricity price futures, which influences future load requirements through price elasticity effects. The price elasticity impacts on future retail electricity consumption levels are based on empirically estimated price elasticities measured from retail customers' historical electricity consumption and price level patterns. There are also cross-price elasticity effects associated with the price of furnace oil, which impacts residential electricity consumption levels in the load forecasts.

of rates during the period. The load forecast results also indicate that whether utility load requirements return to positive growth in the longer term period will also be dependent on the level of rates but in addition can be expected to be influenced by the level of economic growth.

Table 11: Island Utility Electricity Load Growth Summary – 2018 Planning Load Forecast[41]

		2017-2023	2017-2029
Case I: Low Retail Rate	MW	-1.1%	1.9%
	GWh	-1.6%	1.5%
Case II: Mid-Retail Rate	MW	-2.9%	-2.8%
	GWh	-5.0%	-4.1%
Case III: High Retail Rate	MW	-6.2%	-10.9%
	GWh	-6.2%	-10.9%
Case IV: High Growth	MW	-0.8%	6.2%
	GWh	-0.7%	7.7%

Figure 6 highlights that the load forecasts largely move together in the early part of the study period. Following 2022, there begins to be divergence in load forecast as the difference in retail rate between cases increases. By the end of the study period a variance of 200 MW is observed between the High Growth Case and the High Rate Case. This further highlights that the impacts of the level of investment and costs on retail rates and customer reaction to those impacts is currently the most significant driver of uncertainty in the resource planning process.

[41] Utility load is the summation of Newfoundland Power and Hydro Rural Requirements.

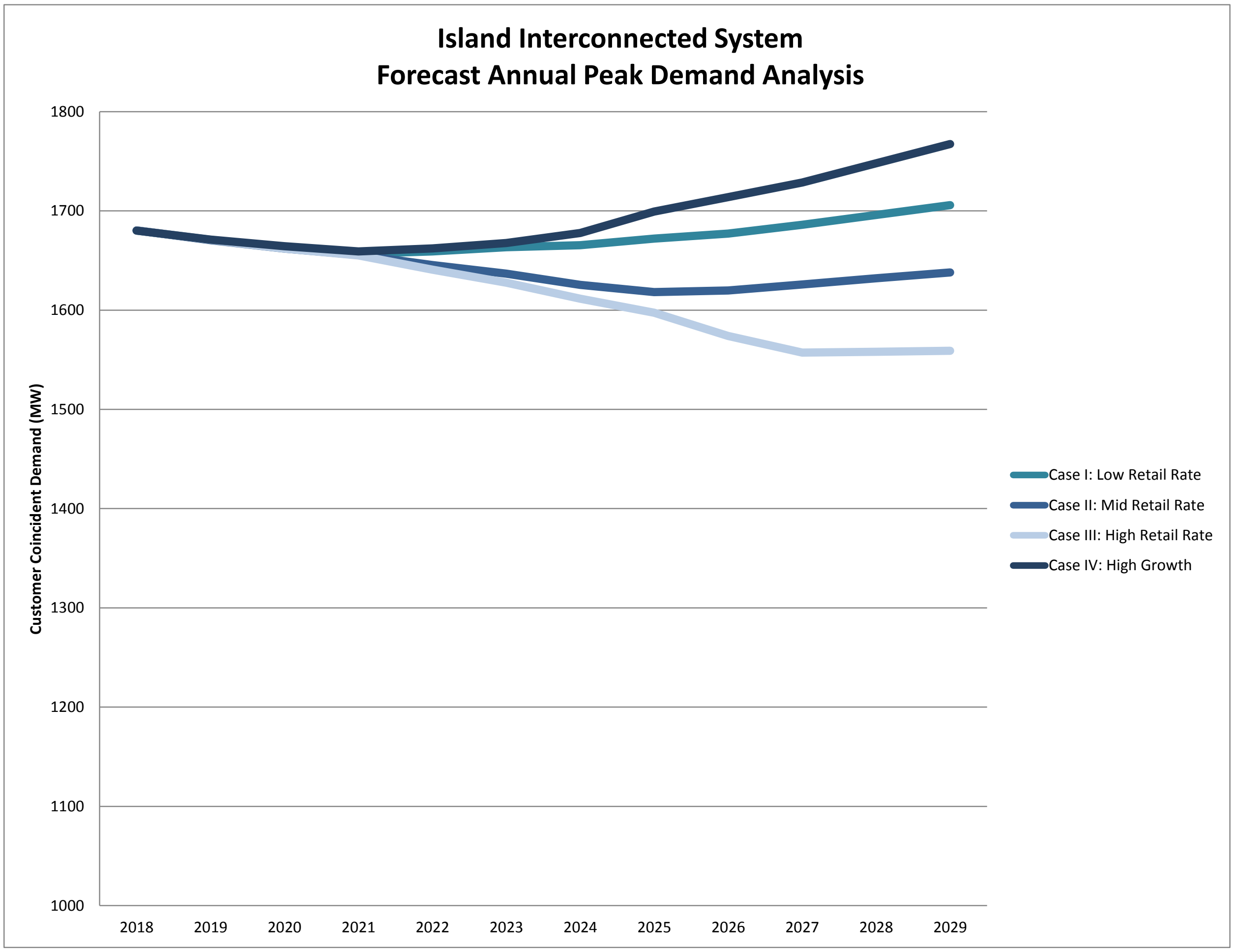


Figure 6: IIS Forecast Annual Peak Demand Analysis

Industrial load requirements for the IIS for the 2019 through 2028 period reflect the load requirements indicated by the customers. The forecast industrial loads are essentially flat with minor reductions in power and energy requirements for the pulp and paper mill operations at Corner Brook.

5.3 Considered Potential Labrador Load Scenarios

The LIS load includes the power and energy requirements of the iron ore industry in western Labrador and Hydro's rural customers connected to the Churchill Falls Hydroelectric Generating Station. The communities include Happy Valley-Goose Bay (including North West River, Sheshatshiu, and Mud Lake), Wabush, Labrador City, and regulated Churchill Falls townsite customers.

Table 12 presents the base forecast with sensitivities for the total LIS over the study period. The base forecast reflects Hydro Rural Load Forecast, spring 2018, which includes existing data centre requirements and additional data centre requirements of customers approved for service at June 2018. The base case forecast for this planning exercise does not currently include loads associated with Wabush mine reactivation by Tacora Resources, however, sensitivity cases were developed to study the impact of potential large loads, including the reactivation of Wabush mine, data centre development in Labrador East and West, and additional load requirements for the Department of National Defence ("DND") at 5 Wing Goose Bay. Note that the cases were developed on a stand-alone basis, meaning any combination of the options presented could occur.

Sensitivity cases were developed to study the impact of potential large loads in Labrador (i.e. reactivation of Wabush mine, additional load requirements from DND, potential data center development)

Table 12: Labrador Utility Electricity Load Growth Summary–
2018 Planning Load Forecast[42,43,44]

		2017-2023[45]	2017-2029
Base Case	MW	-3.5%	-2.4%
	GWh	2.1%	2.9%
Case I: Increased requirements at DND	MW	-0.9%	0.2%
	GWh	4.1%	4.8%
Case II: Data Centre Development – Lab East	MW	3.5%	4.6%
	GWh	12.1%	12.8%
Case III: Data Centre Development – Lab West	MW	8.0%	9.1%
	GWh	16.9%	17.6%
Case IV: Mine Redevelopment	MW	9.2%	10.3%
	GWh	20.1%	20.9%

As any combination of the cases could occur, the analysis was rationalized to focus on three potential load growth scenarios for Labrador; the base case, a high industrial growth case, and a case where all recapture is consumed in Labrador within the study period, detailed in Table 13.

[42] Electricity load includes the summation of Happy Valley-Goose Bay (including North West River, Sheshatshiu, and Mud Lake), Wabush, Labrador City, and industrial customers.
[43] Peaks (MW) are from terminal station delivery points and are coincident with LIS peak. They are presented on a winter peak basis and include firm requirements for industrial customers.
[44] Electricity loads do not include retails sales for Churchill Falls, which has an annual energy load of 2,400 GWh and a non-coincident peak of 0.3MW.
[45] 2017 peak includes non-firm requirements being taken by IOC, contributing to the decrease in peak requirements.

Table 13: Labrador Load Growth Scenarios Considered

Case	Details
Base Case	• Reflects the base forecast detailed above; • Includes existing data centre requirements and additional data centre requirements of customers approved for service at June 2018; and • Does not include loads associated with Wabush mine reactivation by Tacora Resources.
High Industrial Growth Case	• Reflects high industrial growth in the region; and • Includes loads associated with Wabush mine reactivation by Tacora Resources in Labrador West and additional load requirements from DND in Labrador East.
All Recapture Consumed in Labrador	• A representative case designed to evaluate sensitivity of provincial supply to availability of remaining recapture; and • Assumes load growth in the region occurs to the extent that all available supply is fully consumed.

6 Reserve Margin Criteria

6.1 Long-Term Reserve Margin Target

The reserve margin target specifies the reserve margin required to provide the required level of system reliability. In the resource planning process it is used to identify when incremental resources are required to provide adequate system reliability. As detailed in Volume I, Table 14 below outlines the recommended capacity planning criteria.

Table 14: Planning Reserve Margin Results

	Newfoundland and Labrador Interconnected System	Island Interconnected System
LOLE[46] (Days/year)	0.1	0.1
Planning Reserve Margin (%)	13%	14%

[46] Loss of Load Expectation ("LOLE")

These criteria were used to determine when capacity expansion would be required in each case considered.

6.1.1 Operational Reserves

Volume I also detailed the requirement for operational reserves as detailed in Table 15. The High Power Operational Studies have indicated that operational reserves can be held anywhere within the NLIS. These requirements are included in Hydro's Resource Planning Model.

Table 15: Operational Reserve Requirements Results

	Operational Reserve Required
Ten Minute Reserves	197.5 MW
Thirty Minute Reserves	99 MW
Total	**296.5 MW**

Further, as noted in Volume I, Section 3.3.1, there is a requirement for a portion of the ten minute operational reserve to be synchronized to the system, also referred to as spinning reserve. Spinning reserve refers to the unloaded generating capacity connected to the system that is not actively meeting customer requirements (e.g., a hydraulic unit capability of 76.5 MW that is loaded to 50 MW is providing 16.5 MW of spinning reserve). Spinning reserve is an important part of system operation as units providing spinning reserve can rapidly increase power output as required to provide for system regulating support and to respond to supply interruption. This provides a faster response time when compared to units that have to be started after a system disturbance occurs. As per the Northeast Power Coordinating Council ("NPCC") guidelines, a utility must have a minimum of 25 percent of the ten-minute reserve quantity synchronized to the system, with the remaining ten-minute reserve fully available within the required ten minutes.[47]

[47] "Regional Reliability Reference Directory # 5 Reserve," NPCC, October 11, 2012 <https://www.npcc.org/Standards/Directories/Directory_5-Full%20Member%20Approved%20clean%20-GJD%2020150330.pdf>

The requirements for each of the ten minute, thirty minute, and spinning reserve impact overall system operation, production cost, and the type of resource best suited to meet projected system requirements. Additionally, a unit's ability to contribute to reserves is based on the characteristics of that particular unit. For example, if a unit has a minimum start time or ramp rate that prevents it from being placed online and loaded within ten minutes, either that unit must be placed online in advance to contribute its rated capacity to ten-minute reserves, or only the portion of the units capacity that is available to the system within the specified ten minutes is to be counted as ten minute reserves. This is often the case in Hydro's current operation with the Holyrood GT, for example, as to meet system reserve requirements the unit must be placed online in advance given the time required to start and load that particular unit. By including these criteria in the determination of the least-cost resource option, the ability of incremental resources to reduce the costs associated with providing ten minute, thirty minute, and spinning reserve is considered.

As such, these requirements have been included in the Resource Planning Model, as follows:

1) Ten Minute Operational Reserve: Equal to the MW output of the largest unit operating on the system. Note that with the exception of the subset of the ten minute reserve that is required to be spinning, units providing this reserve must be available to generate at specified capability within ten minutes.

   a. Spinning Reserves: The amount of the ten minute reserve required to be synchronized to the system. Units providing this capacity must be available and generating in the hour they are providing spinning reserve. As the amount of the ten-minute reserve that is required to be spinning is subject to past-performance, to be conservative it is assumed that 100 percent of the ten minute reserve could be required to be spinning in the model.

2) Thirty Minute Operational Reserve: Equal to half of the MW output of the second largest unit operating on the system. Units providing thirty minute reserve do not have to be online, but must be able to be placed online and generating at specified capability within thirty minutes.

6.2 Additional Case Analysis: Supplying Customers in the Event of the Prolonged Loss of the Labrador-Island Link

In addition to the reasonably expected load cases described previously, Hydro presents an additional case for information. With the introduction of the MFGS, a large portion of the generation serving the Island load will be located in Labrador. Therefore, the reliability of the LIL is a key driver of NLIS reliability. Volume I, Attachment 7 provides a Technical Note which discusses the robust nature of the design and construction of the LIL, the anticipated asset reliability, and the anticipated required maintenance. While Hydro is confident in the design and construction of the LIL, it recognizes that the Board and parties wish to better understand the implications associated with a prolonged outage of the LIL.

Design of the LIL was undertaken using the overhead line design standards in force at the time, namely *CAN/CSA C22.3 No. 1* and *CAN/CSA C22.3 No. 60826*. A significant amount of historical data, including historical and modern studies, on-site test tower data, as well as local experience when available, was utilized in the determination of the meteorological loading. Eleven different loading zones were required over the 1,100 kilometre line length as part of the optimization of the line design with the construction cost. These include various combinations of wind and ice through heavy glaze ice zones, coastal zones, and heavy rime ice (in-cloud ice) zones. Through an iterative process, line design (including structure spotting and tower designs) was completed following standard design practices to optimize and reduce line failure risk (by ensuring that no towers exceed the design limits) and to further balance the loads on the structures. Due to topological restrictions, such as electrical clearance requirements in hilly terrain, additional capability is inherently built in to many of the structures.

The design of the LIL meets CSA 150-year ice and wind loading recommendations for glaze ice zones off the Avalon Peninsula and 500-year ice and wind loading recommendations on the Avalon Peninsula. For rime ice zones, such as the Long Range Mountains, the line design exceeds 500-year designs for both rime ice and wind in these zones.

In addition to the low risk of transmission line failure due to the selected meteorological loads and the line design process, an emergency restoration plan has been developed for restoration of a single HVdc pole as quickly as possible in the event of line collapse in order to minimize impact for the loss of supply from Labrador. In early October 2018, a successful field test was completed to validate the constructability of the temporary solution for utilization in the near-term. Analysis of the field test results continues to further optimize the near-term solution and to provide input into a long-term emergency restoration plan.

To inform a risk-based analysis of such implications, in addition to modelling the LIL with its anticipated availability, an extended outage case was also modelled. The extended outage models a scenario where the LIL is unavailable for three weeks during January (i.e., during peak) to quantify the resultant system reliability and identify the costs associated with providing incremental generation to reduce the loss of load probability. The unavailability is intended to simulate an icing situation that causes tower collapse in a remote segment of the transmission line.

The installed capacity of the IIS following the retirement of Holyrood is anticipated to be 1,418 MW, which is less than the forecast demand. Further, the High Power Operational Study for the IIS, determined a transmission constraint exists for deliveries to the Avalon Peninsula when the LIL is fully out of service and the Island load is above 1200 MW. As such, in the event of a prolonged outage of the LIL during winter, there would be a generation shortfall on the IIS when load exceeds 1400 MW, and a transmission constraint for deliveries to the Avalon Peninsula when IIS load is between 1200 and 1400 MW. This means that while Island generation would

In addition to the low risk of transmission line failure, an emergency restoration plan has been developed for restoration of a single HVdc pole

continue to supply customers during this period, in any hours where load exceeds what is available on the Island there would be supply interruption for a number of customers. To provide a visual example, Figure 7 shows the exposure for unserved energy if the outage were to occur on a representative P50 forecast peak day. This exposure will continue to increase as load on the Avalon Peninsula increases. Note that this example assumes all other generation is in service.

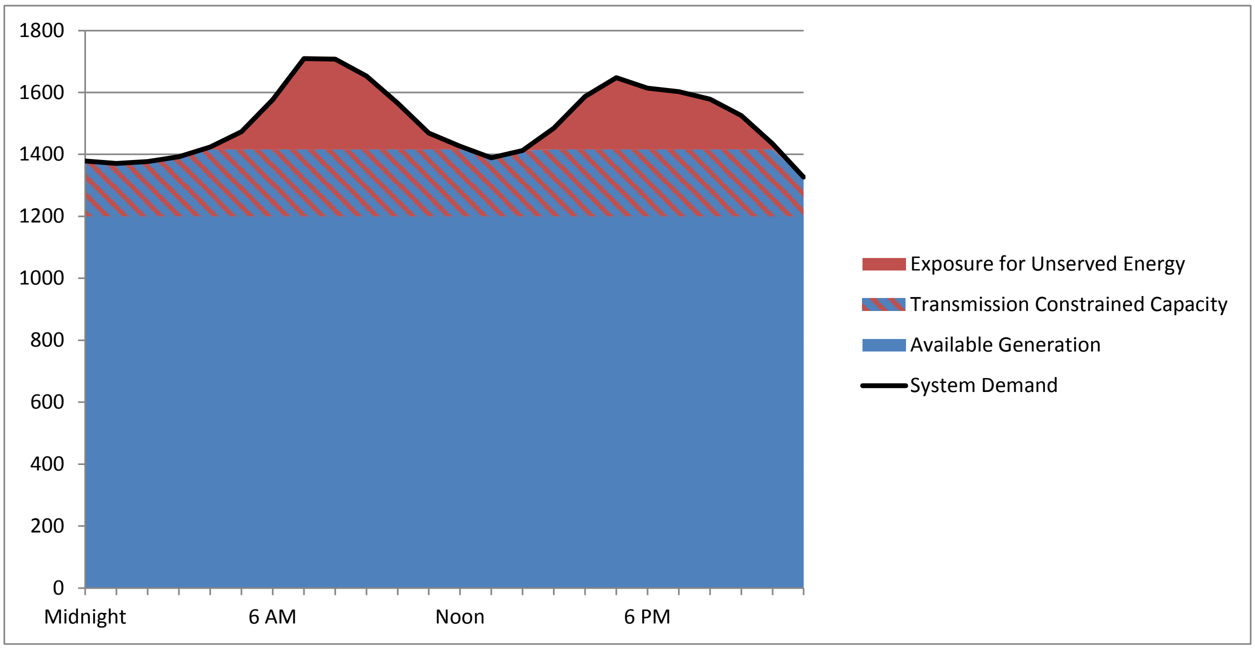


Figure 7: The LIL Outage – Forecast Shortfall on Peak Day

Based on the High Power Operational Study for the IIS, it was determined that a transmission constraint for deliveries to the Avalon Peninsula exists when the LIL is fully out of service and the Island load is above 1200 MW. As such, in the current transmission system, neither the existing capacity assistance contracts nor supply over the Maritime Link would help mitigate the capacity shortfall in this considered scenario.

Hydro has committed to working with TransGrid Solutions to determine if there are any transmission-oriented solutions that can increase the amount of power that could be delivered to the Avalon Peninsula. This would mean that more power from supply located off the Avalon

Peninsula could be delivered to the load centre and that capacity assistance from CBPP or supply from the Maritimes could also be used to assist if the situation were to occur. The work scope for this initiative is currently under development. Hydro commits to updating the Board as this initiative proceeds.

If no transmission-oriented solutions emerge and it is determined through consultation with the Board and intervenors that partial or full mitigation of this risk is required, any potential mitigation of this scenario would require development of resources on the Avalon Peninsula. Further, there are no material hydroelectric resources on the Avalon, wind generation would not provide adequate capacity, solar generation would be mismatched to the seasonality of the requirement, and there would be insufficient time to charge batteries between instances of requirement. As such, the capacity would likely have to be provided by gas turbines. In this case, both capital cost and anticipated fuel cycling that could be required to ensure any stored fuel is not kept past its storage life would result in material increases to system costs.

Figure 8 and Figure 9 provide an indication of the shortfall of supply if the interruption were to occur for three weeks at the period of highest annual demand requirements.

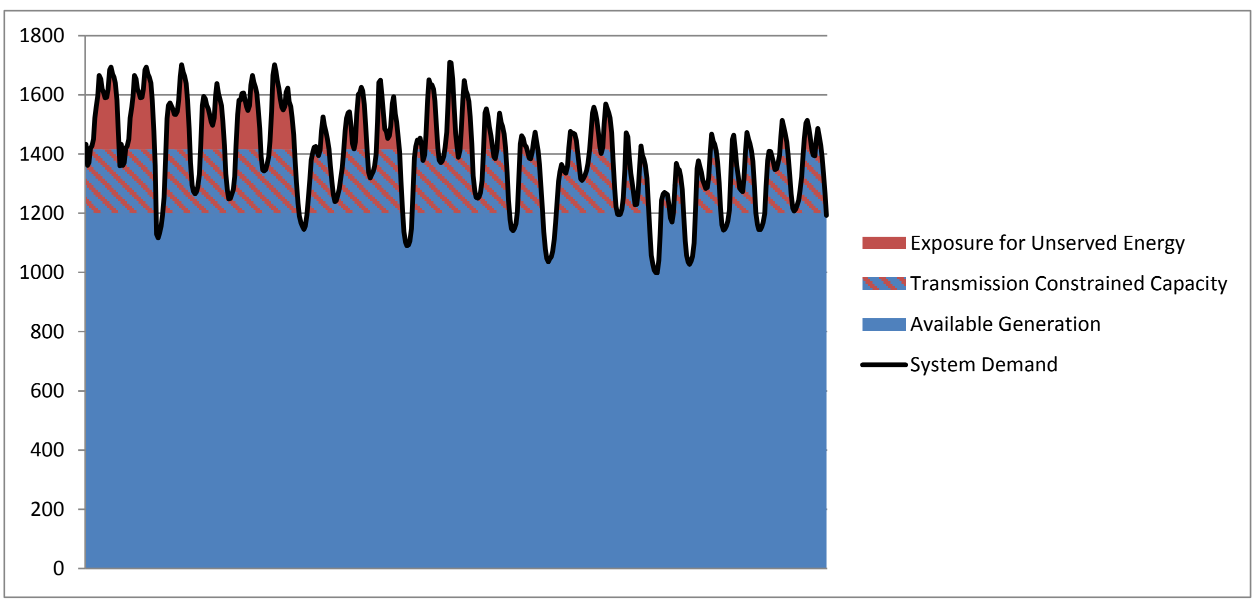


Figure 8: The LIL Outage – Forecast Shortfall through a three-week period, by Day

Figure 8 highlights that if a three-week outage were to occur at time of system peak, heavy rotating outages affecting up to a third of the population at a time could be expected for up to seven days, with rotating outages of lesser magnitude and shorter duration outside that time. Figure 8 also shows that there would likely be days where the majority of customer requirements could be met. Figure 9 plots the load duration curve for the same period.

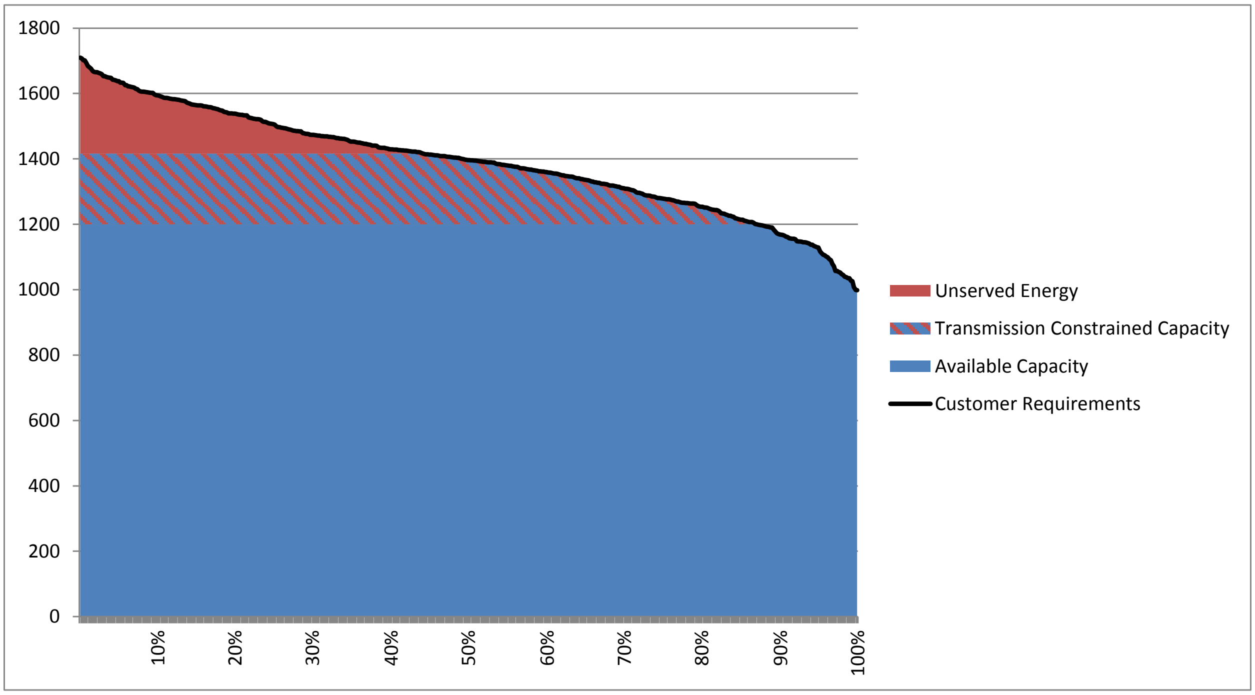


Figure 9: The LIL Outage – Forecast Shortfall through a three-week period

6.2.1 Next Steps

Hydro is committed to better understanding the risk this unavailability poses to the system. While there is always risk inherent in an electrical system (e.g., fire at a critical terminal station, etc.), as new risk is introduced to the system it needs to be well understood, in particular, considering the cost investment and rate impacts for customers. This must be balanced against the low probability, high consequence event.

From a likelihood perspective, the probability of an unplanned bipole outage occurring on the LIL is very low.

From a likelihood perspective, the probability of an unplanned extended bi-pole outage occurring on the LIL is very low. It is even less likely that a situation will occur that sees the link unavailable for up to three weeks, less likely again that this situation will materialize while the system is at peak, and further unlikely that the peak that materializes will be a P90 peak demand. However, no matter how unlikely, there is the possibility that the scenario could occur. Hydro commits to working with the Board and stakeholders to further examine this scenario to determine should any mitigation of this scenario be implemented in the balance of cost and reliability.

6.3 Energy Criteria

The proposed energy criterion is that there must be adequate firm generation on the system to supply firm load on an annual basis.[48]

Energy: The NLIS should have sufficient generating capacity to supply all of its firm energy requirements with firm system capability.

The ability to meet energy requirements is continually evaluated in consideration of historical inflow sequences and future customer and contracted requirements. The NLIS does not violate this criterion through the study period.

[48] Firm capability for the hydroelectric resources is the firm energy capability of those resources under the most adverse three-year sequence of reservoir inflows occurring within the historical record. Firm capability for the thermal resources (Holyrood) is based on energy capability adjusted for maintenance and forced outages.

From an operational perspective, minimum storage targets are developed annually to provide guidance in the reliable operation of Hydro's major reservoirs: Victoria, Meelpaeg, Long Pond, Cat Arm, and Hinds Lake. The minimum storage target is designed to show the minimum level of aggregate storage required such that if there was a repeat of Hydro's critical dry sequence, or other less severe sequence, the IIS load could still be met through the use of the available hydraulic storage, maximum generation at Holyrood while in service, and deliveries over the LIL through the remainder of the study period. Hydro's long-term critical dry sequence is defined as the hydraulic period occurring January 1959 to March 1962 (39 months). Other dry periods are also examined during the derivation to ensure that no other shorter term historic dry sequence could result in insufficient storage.

Currently, there are no forecast violations of the proposed energy criteria. If in future, a potential for violation were identified, the opportunity to procure firm imports to supplement native supply could be considered, and the planning criteria modified appropriately. Other jurisdictions do consider firm imports from an energy planning perspective.

7 Results and Recommendations

The results of the reserve margin-based analysis across all 24 scenarios indicate that the requirement for additional resources is capacity driven and most sensitive to the projections for load growth in Labrador and the use of the P90 weather variable as the base case condition for supply planning assessments.

Of the 24 cases considered, 7 cases required additional resources inside the 10-year study period.

A summary of the incremental resource additions for these cases are included in Table 16. The remaining 17 cases considered require no additional resources through the study period. The full results for all 24 cases considered are included in Volume III, Attachment 15.

Table 16: Scenarios requiring Incremental Resource Additions

Island Load Case	P50 vs P90	Labrador Load Case	Year of resource requirements
Case I: Low Retail Rate	P90	High Industrial Growth	2028 (58.5 MW)
		Recapture Fully Consumed in Labrador	2023 (117 MW)
Case IV: High Load Growth	P50	High Industrial Growth	2028
		Recapture Fully Consumed in Labrador	2026
	P90	Base Labrador Load	2027
		High Industrial Growth	2025 (117 MW)
		Recapture Fully Consumed in Labrador	2022 (117 MW), 2028 (58.5 MW)

Currently, conventional GTs are being selected by the model as the least cost option in all scenarios requiring additional resources. However, as noted in Section 4 of this Study, Hydro is committed to better understanding the roles that CDM, rate structure, and alternative technologies, such as battery storage, can play in the NLIS. Additional information will then feed into Hydro's annual planning cycle, which will be used to determine if these alternatives can meet system requirements at a lower cost than the conventional generation options. As in most cases, incremental resources are not required until later in the study period, there is sufficient time to better understand these options before a final decision is required.

Using the P90 peak demand forecast for supply planning would require additional resources in five cases inside the ten-year study period

In using the P90 weather variable as the base case condition for supply planning assessments to determine whether additional capacity is required, investment is advanced substantially from the late 2020s to 2022 in both cases with above base forecasted growth in Labrador. Embedding load forecast uncertainty in the determination of planning reserve margin increases the conservatism embedded in forecast modelling compared to modelling only the P50 and P90 discretely. Additionally, given that Hydro is recommending planning decisions be made on the more conservative loss of load expectation ("LOLE") of 0.1, there is incremental conservatism included in Hydro's planning process as compared to that previously conducted. Use of the P50 peak demand forecast for supply planning would require additional resources in two cases inside the ten-year study period.

Using the P50 peak demand forecast for supply planning would require additional resources in two cases inside the ten-year study period

Hydro recognizes there is continued value in considering the variability associated with the P90 condition, particularly from a risk awareness and preparedness perspective. However, Hydro proposes that continuing to plan for a P90 peak demand forecast is not in the best interests of customers at this time, particularly when such planning will result in advancement of system expansion. Planning for the P50 peak demand forecast will mean that additional firm capacity currently existing in the system can be used to encourage domestic load growth, with excess capacity then sold to export markets on a declining basis as load grows. This can help reduce the annual revenue requirement until such time that the incremental capacity is required domestically.

It is also recommended that Hydro's long-term resource plans consider high industrial growth in Labrador. As Labrador is currently supplied by energy from Churchill Falls, contractually, there is currently a finite amount of energy available for consumption in the region. This means that any identified requirements over and above what those sources can supply will require additional supply. Should the need arise; it is in the best interest of customers to consider the best option on a provincial basis. This could result in a market purchase of capacity delivered to Labrador or the construction of additional generating sources. The addition of more electricity for any system will require electricity rates to be updated to reflect those costs.

The results for the above indicate that, on a planning reserve margin basis, incremental resources are unlikely to be required before the mid- to late-2020s. Based on this timeline the most cost-effective and prudent approach at this time is to wait until more certainty around utility retail rates, more certainty around potential quantity and timing of industrial Labrador load growth and operational experience with the Lower Churchill Project assets is obtained. This analysis is planned to be revisited annually and will incorporate all evolutions of inputs described in this Study to ensure the system is built to provide reliable, least-cost service to customers. Hydro commits to working with stakeholders and the Board to inform analysis and decision-making around utility rates to help obtain certainty. Further, in the cases where additional resources are required and the need is resultant from a capacity deficiency, potential load growth will be carefully monitored and the role of alternative resources and technologies (e.g., battery storage technology and rate design) will continue to be investigated.

As discussed in Section 6.2, the prolonged unavailability of the LIL is considered a low-probability, high-consequence event. Hydro commits to working with the Board and stakeholders to contemplate how this scenario should be incorporated into Hydro's planning process, particularly in balancing cost and reliability. Hydro also commits to further investigating the potential for and costs of further optimization of the transmission network to alleviate transmission constraints that exist in this operational situation.

7.1 Action Plan

The findings of the study provide important information for consideration by the parties. Hydro looks forward to participating in the regulatory process to further inform parties on the results of this Study and working with stakeholders and the Board to determine which scenarios should drive capital investment. Long-term planning takes a conservative approach, and Hydro will ensure system needs are well understood and all options have been carefully considered before recommending significant investments. Further optimization of results will be undertaken, as required to support decision-making, and also as part of the annual planning exercise.

Through 2019 Hydro commits to:

- **Working with the Board and its consultants to inform the retail rate analysis underway as part of the "Reference on Rate Mitigation Options and Impacts Relating to the Muskrat Falls Project Cost;"**
- **Study the role alternative technologies, such as battery storage technology, in the future NLIS;**
- **Working with TransGrid Solutions to determine if there are any transmission-oriented solutions that can increase the amount of power that could be delivered to the Avalon Peninsula;**
- **Analysing the role alternative rate structures and pricing can play in the NLIS by supporting Newfoundland Power as it executes its rate design evaluation; and**
- **Understanding the potential for demand reduction by jointly executing the 2018 CDM Potential Study with Newfoundland Power.**

In the long-term, by conducting this analysis annually, the impact of any changes in key inputs that materialize over the course of the year will be included in Hydro's analysis in a timely manner.

Attachment 1

Presentation Shared with Industrial Customers

2018 Reliability Review and Supply Adequacy Assessment

newfoundland labrador
hydro
a nalcor energy company

2018 Objectives

- Ensure adequacy of supply post-interconnection
  - Complete review of generation planning criteria
  - Development of new system model
  - Culminating in a report to the Board in November
- Working with Regulatory consultant to evaluate against North American standards
- Determine, in consultation with stakeholders, customers, and the Board, an appropriate balance of cost and reliability

newfoundland labrador hydro
a nalcor energy company

2018 Filing

- Report to the Board on November 15, 2018
- Propose report contains two volumes:
  - Volume I: (***filed in November 2018 only***)
    - Review of historical and industry practices
    - Recommended criteria and assumptions
    - Setting of reserve margin target
    - Alternate reserve margin targets for sensitivities
  - Volume II: (***updated and filed annually***)
    - Assessment of 10-year supply adequacy
      - Includes generation and transmission
    - Identification of sources of supply
    - Expansion required to meet planning criteria

Stakeholder Engagement

- Hydro recognizes the importance of this analysis to the future electrical system
  - Makes stakeholder engagement extremely important component of this initiative.
- Scope developed and presented to Public Utilities Board
- Consultation with Newfoundland Power, Industrial Customers planned
- Direct customer engagement planned

Consultation with Industrial Customers

- Stakeholder in this initiative
- Ongoing initiatives:
  - Key Accounts Manager
- Questions/ Comments about this study or the process?

newfoundland labrador hydro
a nalcor energy company

Balance of Cost and Reliability

- Over last number of winters, have been dispatching spinning reserve to cover the largest system contingency
  - Operating in this manner is in accordance with North American industry standards
  - Has resulted in increased gas turbine operation over historical use
  - Recognize that operating in this way has been costly
- Questions/comments about this mode of operation for upcoming winter

newfoundland labrador hydro
a nalcor energy company

Appendix

Study Considerations

- Impact on rates
- Generation options
- Cost of new generation
- Unit reliability and available capacity
- Load shape
- Forecast and sensitivities
- Wind generation
- Hydrology
- Transmission constraints
- External markets

newfoundland labrador hydro
a nalcor energy company

Options, if required

- Options to be considered:
  - Fast start gas turbines
  - Combined Cycle Combustion Turbine (170 MW)
  - New hydro (Island Pond, Round Pond, Portland Creek, etc)
  - Hydro units (Bay D'Espoir 8, Cat Arm 3)
  - Wind
  - Solar
  - Customer Demand Management
  - Curtailable load
  - Market purchases
  - Time of Use rates
  - Others

newfoundland labrador hydro
a nalcor energy company

Attachment 2

Meeting Minutes and Correspondence from Engagement with Industrial Customers

September 5, 2018

Mr. Larry Marks
CBPPL

Dear Mr. Marks;

Thank you for taking the time to participate in Hydro's 2018 Reliability Review and Supply Adequacy Assessment engagement session. As we outlined in the meeting, as Hydro undergoes its reliability review and supply adequacy assessment, it's important to us that we receive feedback from our partners, stakeholders and customers. Attached are the meeting minutes and a copy of the session presentation for your review.

A summary of the key feedback received is outlined below:

Overview of Hydro's Supply Adequacy Assessment

- CBPPL commented that the assessment study scope is comprehensive.

Reliability for Winter 2018/19

- CBPPL expects that this coming winter season will be similar to previous winters, costs/rates would be as expected with no surprises
- CBPPL did not have a position for this coming winter as to Cost vs Reliability and spinning reserves
- CBPPL asked what is the impact of Churchill Falls power coming to the island for this winter
    - Hydro is working with its Power Supply partners on a staged approach with bringing the Labrador Island Link (LIL) assets online
    - Hydro highlighted that the LIL will need to be proved reliable before it alters its generation dispatch and asset base.

Should you have any concerns on the representation of the content within this letter or attachments, or any additional comments please contact me directly by September 12, 2018.

Regards,

Robert Coish
Key Accounts
Newfoundland and Labrador Hydro

e.c.c.

Renee Smith – Resource & Production Planning (NL Hydro)
Erin Squires – Communications (NL Hydro)
Carl Bishop – Customer Care (NL Hydro)

/Attached

- *Meeting Minutes:* "2018 Reliability Review and Supply Adequacy Assessment Meeting Minutes CBPPL 2018-08-20"
- *Presentation:* "Reliability Criteria Presentation August 2018"

2018 Reliability Review and Supply Adequacy Assessment

Industrial Customer Stakeholder Engagement (CBPPL)

Meeting Minutes – August 22, 2018 (1300-1335)

Action List Summary

Action #	Description	Owner	Target Date
1	CBPPL to provide Hydro with Annual Energy Numbers	Larry Marks	2018-10-15

Attendance

CBPPL: Larry Marks (Regrets: Darren Pelley, Ric Tull)
NLH: Renee Smith, Erin Squires, Robert Coish

Location Teleconference (2018-08-22, 1300-1335 hours)

Safety moment

1. When in an unfamiliar building, such as a hotel, stadium, gym, etc., take note of alternate exits. The entrance you came in from, may look different going out, or may not be available as an exit (eg. it could be blocked). Take the time to make yourself familiar with how to get out of the building in an emergency. Discuss with family, friends, and other members of your party in attendance.

Discussion

1. Introduction
    - Attendees introduced themselves and their roles.
2. 2018 Reliability Review and Supply Adequacy Assessment Presentation
    - Renee reviewed the slide presentation
        i. Slide 1 additional discussion:
            1. Hydro has a new software tool that is currently being used to model generation supply parameters. This model is expected to be completed in November 2018.

2. Hydro has and is consulting with Industrial Customers, Consumer Advocate, the PUB, subject matter experts (incl. software modelling vendor).
3. Also being reviewed are utility practices in North America
4. The results of the Review and Assessment will be filed with the PUB

ii. Slide 2 additional discussion:

1. CBPPL asked what is meant by "reserves margin target?" Hydro described that historically Hydro has used Loss Of Load Hours (LOLH) as the target. [*Loss of Load Hours (LOLH) is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity*][1]. This assessment will provide recommendations at to the appropriate target for Hydro to use in the future.
2. CBPPL asked if the 10-year supply adequacy is for Hydro, Nalcor, or provincially. Hydro indicated that it is provincially and Hydro (that includes preexisting contracts with Nalcor)

iii. Slide 3 additional discussion:

1. Hydro: Traditionally this assessment has been done purely based on a technical basis. More engagement is the goal with this assessment (eg. industrial customers, consumer advocate, Newfoundland Power, residential/commercial customers [both Hydro and Newfoundland Power's]).

iv. Slide 4 additional discussion:

1. CBPPL commented that the assessment study scope is comprehensive.

v. Slide 5 additional discussion:

1. CBPPLs Capacity Assistance is part of the reserves system
2. CBPPL asked what is the impact of Churchill Falls power coming to the island for this winter
    a. Hydro is working with its Power Supply partners on a staged approach with bringing the Labrador Island Link (LIL) assets online
    b. Hydro highlighted that the LIL will need to be proved reliable before it alters its generation dispatch and asset base.
3. CBPPL asked what has been the cost of Gas Turbine fuel
    a. As reported to the PUB, the balance of costs for dispatching spinning reserves for 2015,2016, and 2017 is

approximately $65M, with approximately $55-$60M being gas turbine operating costs

4. CBPPL asked if it will be business as usual for this winter
    a. Not necessarily. This will be a recommendation coming out of the assessment study.

vi. Appendix

1. CBPPL asked if it is correct to assume these options will have an impact on rates?
    a. Hydro will look at all options individually for least cost alternative, and will continue consultations with stakeholders.

3. General Commentary from CBPPL

- CBPPL asked is Hydro was satisfied with the current Capacity Assistance arrangement?
    i. Hydro is satisfied with this product from CBPPL.
- Hydro asked if CBPPL can provide a quick summary of their 50 Hz to 60 Hz conversion project
    i. 23 MW of new 60 Hz generation (104 MW of 60 Hz total). The target date for the conversion is Nov 5th week.
- Hydro asked what CBPPL's energy profile will be
    i. CBPPL is in the process of changing paper specs and updating production models which will change their energy models. Mostly likely their production will use less energy than previously and will have more energy to transfer externally (eg. the power grid, markets)
- CBPPL expects that this coming winter season will be similar to previous winters, costs/rates would be as expected with no surprises

ACTION: Larry Marks to provide update average energy numbers.

- CBPPL did not have a position for this coming winter as to Cost vs Reliability and spinning reserves

Reliability Criteria Presentation August :

Meeting Adjourned

1. North American Electric Reliability Corporation (NERC); Probabilistic Adequacy and Measures Technical Reference Report Final April 2018, Page 12 (https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf)

October 15, 2018

Mr. Corey Holloway
NARL

Dear Mr. Holloway;

Thank you for taking the time to participate in Hydro's 2018 Reliability Review and Supply Adequacy Assessment engagement session. As we outlined in the meeting, as Hydro undergoes its reliability review and supply adequacy assessment, it's important to us that we receive feedback from our partners, stakeholders and customers. Attached are the meeting minutes and a copy of the session presentation for your review.

A summary of the key feedback received is outlined below:

Overview of Hydro's Supply Adequacy Assessment

- NARL commented that the feedback process loop is established and is working between both parties.

Reliability for Winter 2018/19

- NARL's biggest concern is reliability of Power Supply. Reliability is critical to the refinery processes. Not as concerned with costs, as unplanned shutdowns can cost millions of dollars.
- NARL expects Hydro to keep the supply of power reliable. Cost is important, but reliability of supply is paramount.

Should you have any concerns on the representation of the content within this letter or attachments, or any additional comments please contact me directly by October 31, 2018.

Regards,

Robert Coish
Key Accounts
Newfoundland and Labrador Hydro

e.c.c.

Bruce Avery – CFO (NARL)
Terry Ma – Manager, Capital / Maintenance (NARL)

Renee Smith – Resource & Production Planning (NL Hydro)
Erin Squires – Communications (NL Hydro)
Carl Bishop – Customer Care (NL Hydro)

/Attached

- *Meeting Minutes:* "2018 Reliability Review and Supply Adequacy Assessment Meeting Minutes NARL 2018-09-12 v2018-10-15-1530"
- *Presentation:* "Reliability Criteria Presentation August 2018"

2018 Reliability Review and Supply Adequacy Assessment

Industrial Customer Stakeholder Engagement (North Atlantic Refining Limited Refining Limited Partnership)

Meeting Minutes – September 12, 2018 (1300-1400)

Attendance

NARL:	Bruce Avery, Terry Ma, Corey Holloway, Mohammed Zilani
NLH:	Renee Smith, Erin Squires, Robert Coish

Location Teleconference (2018-09-12, 1300-1400 hours)

Safety moment

1. When in an unfamiliar building, such as a hotel, stadium, gym, etc., take note of alternate exits. The entrance you came in from, may look different going out, or may not be available as an exit (eg. it could be blocked). Take the time to make yourself familiar with how to get out of the building in an emergency. Discuss with family, friends, and other members of your party in attendance.

Discussion

1. Introduction
   - Attendees introduced themselves and their roles.
2. 2018 Reliability Review and Supply Adequacy Assessment Presentation
   - Previous objectives were on an Isolated Island bases. There are now changes with the interconnection with Labrador & Quebec (Labrador Transmission Assets, Labrador Island Link), and Nova Scotia (Maritime Link)
   - Renee reviewed the slide presentation
     i. Slide 1 additional discussion:
        1. Hydro has a new software tool that is currently being used to model generation supply parameters. This model is expected to be completed in November 2018.
        2. Hydro has and is consulting with Industrial Customers, Consumer Advocate, the PUB, subject matter experts (incl. software modelling vendor).
        3. Also being reviewed are utility practices in North America

        4. The results of the Review and Assessment will be filed with the PUB

ii. Slide 2 additional discussion:

    1. NARL did not have any comments at this time.

iii. Slide 3 additional discussion:

    1. Hydro: Traditionally this assessment has been done purely based on a technical basis. More engagement is the goal with this assessment (eg. industrial customers, consumer advocate, Newfoundland Power, residential/commercial customers [both Hydro and Newfoundland Power's]).
    2. NARL: Biggest concern is reliability of Power Supply. Reliability is critical to the refinery processes. Not as concerned with costs, as unplanned shutdowns can cost millions of dollars.
    3. NARL commented the feedback loop between them and Hydro has been established.
    4. NARL asked how they are part of the Reliability Plan.
        a. Hydro is reviewing NERC & NPCC Standards.
        b. Hydro would not export power to the detriment of Hydro's provincial requirements.
        c. Maritime Link has been established in 2018. And was used twice in providing emergency stability to the power grid.
        d. In general interconnects bring stability to the power grid.
        e. Where practical, Hydro will import lower cost power from outside of the province.
        f. Hydro has upgraded many 230 kV circuits on the island, this will increase stability to the power grid.

iv. Slide 4 additional discussion:

    1. NARL expects Hydro to keep the supply of power reliable. Cost is important, but reliability of supply is paramount.

v. Slide 5 additional discussion:

    1. NARL did not have any comments at this time.

Reliability Criteria
Presentation August :

Meeting Adjourned

September 5, 2018

Mr. Shawn Kinsella
Teck Resources (Duck Pond)

Dear Mr. Kinsella;

Thank you for taking the time to participate in Hydro's 2018 Reliability Review and Supply Adequacy Assessment engagement session. As we outlined in the meeting, as Hydro undergoes its reliability review and supply adequacy assessment, it's important to us that we receive feedback from our partners, stakeholders and customers. Attached are the meeting minutes and a copy of the session presentation for your review.

A summary of the key feedback received is outlined below:

Overview of Hydro's Supply Adequacy Assessment

- Teck Resources is satisfied that the assessment study scope is comprehensive.
- Teck Resources provided comment that they have not had any issues with Hydro's supply.

Reliability for Winter 2018/19

- Teck Resources, with operations currently shutdown, does not produce any revenue and therefore prefers to reduce its costs. A longer power outage (for example, from 5-10 minutes to 60-90 minutes) would be acceptable in order to reduce electricity costs.
- Teck Resources has three onsite generators (500 kVA each) and can maintain its own power requirements using just one of these generators.

Should you have any concerns on the representation of the content within this letter or attachments, or any additional comments please contact me directly by September 12, 2018.

Regards,

Robert Coish
Key Accounts
Newfoundland and Labrador Hydro

e.c.c.

Renee Smith – Resource & Production Planning (NL Hydro)
Erin Squires – Communications (NL Hydro)
Carl Bishop – Customer Care (NL Hydro)

/Attached

- *Meeting Minutes:* “2018 Reliability Review and Supply Adequacy Assessment Meeting Minutes Teck 2018-08-20”
- *Presentation:* “Reliability Criteria Presentation August 2018”

2018 Reliability Review and Supply Adequacy Assessment

Industrial Customer Stakeholder Engagement (Teck Resources Duck Pond)

Meeting Minutes – August 20, 2018 (0930-0950)

Attendance

Teck Resources:	Shawn Kinsella (Regrets: Larry Bartlett, Lewis Patey)
NLH:	Renee Smith, Erin Squires, Robert Coish

Location Teleconference (2018-08-20, 0930-0950 hours)

Safety moment

1. When in an unfamiliar building, such as a hotel, stadium, gym, etc., take note of alternate exits. The entrance you came in from, may look different going out, or may not be available as an exit (eg. it could be blocked). Take the time to make yourself familiar with how to get out of the building in an emergency. Discuss with family, friends, and other members of your party in attendance.

Discussion

1. Introduction
   - Attendees introduced themselves and their roles.
2. 2018 Reliability Review and Supply Adequacy Assessment Presentation
   - Renee reviewed the slide presentation
     - i. Slide 1 additional discussion:
       1. Hydro has a new software tool that is currently being used to model generation supply parameters. This model is expected to be completed in November 2018.
       2. Hydro has and is consulting with Industrial Customers, Consumer Advocate, the PUB, subject matter experts (incl. software modelling vendor).
       3. Also being reviewed are utility practices in North America
       4. The results of the Review and Assessment will be filed with the PUB
     - ii. Slide 5 additional discussion:

1. Reliability Costs. The balance of costs for dispatching spinning reserves for 2015,2016, and 2017 is approximately $65M, with approximately $55-$60M being gas turbine operating costs.
2. If Hydro did not dispatch its generators in this way, costs would decrease, however reliability would also decrease. It is possible that a 5-10 minute outage (with dispatched spinning reserves) may increase to 60-90 minutes (without dispatched spinning reserves).

3. General Commentary from Teck Resources Duck Pond
   - Teck Resources is satisfied that the assessment study scope is comprehensive.
   - Teck Resources provided comment that they have not had any issues with Hydro's supply.
   - Teck Resources, with operations currently shutdown, does not produce any revenue and therefore prefers to reduce its costs. A longer power outage (from 5-10 minutes to 60-90 minutes) would be acceptable in order to reduce electricity costs.
   - Teck Resources has 3 onsite generators (500 kVA each) and can maintain its own power requirements using just one of these generators.

Meeting Adjourned

September 5, 2018

Mr. Jason Callan
Vale

Dear Mr. Callan;

Thank you for taking the time to participate in Hydro's 2018 Reliability Review and Supply Adequacy Assessment engagement session. As we outlined in the meeting, as Hydro undergoes its reliability review and supply adequacy assessment, it's important to us that we receive feedback from our partners, stakeholders and customers. Attached are the meeting minutes and a copy of the session presentation for your review.

A summary of the key feedback received is outlined below:

Overview of Hydro's Supply Adequacy Assessment

- Vale did not have any comments at this time.

Reliability for Winter 2018/19

- Vale would expect to have spinning reserves maintained as previously, however understanding the use of GTs should be reduced due to the recent system changes (eg. TL267, LIL, Maritime Link). If these are not available, then run GTs as required.

Should you have any concerns on the representation of the content within this letter or attachments, or any additional comments please contact me directly by September 12, 2018.

Regards,

Robert Coish

Key Accounts
Newfoundland and Labrador Hydro

e.c.c.

Renee Smith – Resource & Production Planning (NL Hydro)
Erin Squires – Communications (NL Hydro)
Carl Bishop – Customer Care (NL Hydro)

/Attached

- *Meeting Minutes:* "2018 Reliability Review and Supply Adequacy Assessment Meeting Minutes Vale 2018-08-20"
- *Presentation:* "Reliability Criteria Presentation August 2018"

2018 Reliability Review and Supply Adequacy Assessment

Industrial Customer Stakeholder Engagement (Vale)

Meeting Minutes – August 23, 2018 (0930-1000)

Attendance

Vale:	Jason Callan, Jamie Wells
NLH:	Renee Smith, Erin Squires, Robert Coish

Location Teleconference (2018-08-23, 0930-1000 hours)

Safety moment

1. When in an unfamiliar building, such as a hotel, stadium, gym, etc., take note of alternate exits. The entrance you came in from, may look different going out, or may not be available as an exit (eg. it could be blocked). Take the time to make yourself familiar with how to get out of the building in an emergency. Discuss with family, friends, and other members of your party in attendance.

Discussion

1. Introduction
    - Attendees introduced themselves and their roles.
2. 2018 Reliability Review and Supply Adequacy Assessment Presentation
    - Renee reviewed the slide presentation
        - i. Slide 1 additional discussion:
            1. Hydro has a new software tool that is currently being used to model generation supply parameters. This model is expected to be completed in November 2018.
            2. Hydro has and is consulting with Industrial Customers, Consumer Advocate, the PUB, subject matter experts (incl. software modelling vendor).
            3. Also being reviewed are utility practices in North America
            4. The results of the Review and Assessment will be filed with the PUB
        - ii. Slide 2 additional discussion:

1. Vale asked what is meant by "post interconnection?" Hydro described that post interconnection means with both the Labrador Island Link (LIL) and Muskrat Falls Generation in service.
    a. The LIL has transferred about 10 GWhs to date, but in a testing/commissioning fashion. It is not released for service at this time.
2. Vale asked if the 10-year supply adequacy is for Hydro, Nalcor, or provincially. Hydro indicated that it is provincially and Hydro (that includes preexisting contracts with Nalcor)

iii. Slide 3 additional discussion:
1. Hydro: Traditionally this assessment has been done purely based on a technical basis. More engagement is the goal with this assessment (eg. industrial customers, consumer advocate, Newfoundland Power, residential/commercial customers [both Hydro and Newfoundland Power's]).

iv. Slide 4 additional discussion:
1. Vale did not have any comments at this time.

v. Slide 5 additional discussion:
1. If Hydro did not dispatch its generators in this way, costs would decrease, however reliability would also decrease. It is possible that a 5-10 minute outage (with dispatched spinning reserves) may increase to 60-90 minutes (without dispatched spinning reserves).
    a. Vale: With the third transmission line (TL267) and interconnection, will this change reliance on GT usage?
    b. Hydro: Yes, these factors should decrease the reliance on GTs. However if these assets are not in service, than what is Vale's view on dispatching spinning reserves?
    c. Vale: Would expect to have spinning reserves maintained as previously, however understanding the use of GTs should be reduced due to the recent system changes (eg. TL267, LIL, Maritime Link). If these are not available, then run GTs as required.

vi. Appendix
1. Vale: Would additional generation assets be required once Muskrat Falls is online?
    a. Hydro: It is a possibility, but the assessment will provide more information

Reliability Criteria
Presentation August :

Meeting Adjourned

Attachment 3

2018 Digital Engagement Initiative Summary Report

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2018 Digital Engagement Initiative

Summary Report

October 2018

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Background & Objectives

Newfoundland and Labrador Hydro (NL Hydro) is a provincial Crown corporation that is the primary generator of electricity for Newfoundland and Labrador (NL). In addition, the Company distributes electricity to rural communities in the province, as well as in Labrador. The Company is a subsidiary of Nalcor Energy.

The primary objective of this digital engagement initiative was to provide an opportunity for NL residents and businesses to become actively engaged in the conversation on electricity in the province. In particular, the online study provided an avenue for input and feedback on various topics related to the future NL's electricity system and:

- Assessed overall perceptions regarding the reliability of Hydro's current system among residents across Newfoundland & Labrador;
- Explored opinions regarding the appropriate balance between reliability and the cost of those investments for customers;
- Evaluated residents' interest in taking a more active role in managing their electricity consumption; and
- Assessed residents' level of interest in engagement with Hydro on a go forward basis.

Survey Type	Online
Field Dates	August 28 – September 20, 2018
# of Completes	2,070
Average Survey Length	16 minutes

To meet study objectives, NL Hydro and its agency of record (NATIONAL) commissioned Corporate Research Associates to implement a **Digital Engagement Study**. In particular, through various digital engagement strategies, residents were encouraged to visit a website and share their thoughts by reviewing short information videos and completing an online survey. In total, 2,070 surveys were completed between August 28 and September 20, 2018. When residents were unable to complete the survey online, the opportunity was provided to complete the study by phone. This study was not intended to provide results to which a margin of error can be applied (given that it is not a probability sample), but rather was conducted to actively engage residents in the discussion. That said, overall results were weighted by region to reflect the actual population distribution.

The following summary report presents an overview of the ***2018 Digital Engagement Study*** and includes an executive summary of results and an analysis of findings. For questions that include regional comparisons, results have been broken out by St. John's/Avalon, East and West. Note, while Labrador is included as part of West regional results, results from Labrador have also been presented separately, where relevant. Appended to this report is a copy of the questionnaire (Appendix A).


Executive Summary
Respondent Profile
Hydro's Current System
Reliability & Rates
Customer Options

Executive Summary

Results of the ***2018 Digital Engagement Initiative*** show that while there are some key differences across regions and customer type, respondents are generally content with the current state of Newfoundland and Labrador's power system. Respondents consider their electricity service to be highly reliable, with a sizable minority reporting that their power reliability has improved since DarkNL. Furthermore, respondents are clearly cost-sensitive when it comes to energy upgrading, expressing willingness to accept a risk of longer outages, in favour of minimal rate increases.

Overall, the majority of respondents are comfortable with the level of reliability offered by the current power system, and as such, prefer additional investments be made cautiously. Indeed, while some think the Province needs a more reliable system than it has currently, when asked their preferred approach towards balancing investment and electricity cost, a clear majority of respondents are in favour of Hydro having some back up generation to partially reduce the impact of a sudden loss of power supply, as it would have a lower impact on electricity costs.

Interestingly, despite cost-sensitivity and apparent willingness to accept longer outages, results suggest respondents would be reluctant to accept an increased frequency of outages. On average, respondents reportedly experienced three outages in the past 12 months. However, regardless of their preferred balance of reliability and impact on electricity cost, few consider more than three outages to be acceptable.

Respondents readily acknowledge that consumers have a role to play in actively managing electricity consumption, and are keenly interested in learning more about their own electricity usage, in real-time. Moreover, the vast majority of respondents would like to have more customer rate options available. Despite interest however, respondents offer limited suggestions as to what options could be offered by Hydro, outside of Time-of-Use rates. That said, interest in Time-of-Use rates is strong, with the vast majority of respondents expressing some level of interest in signing up.

Overall, results reveal limited awareness of Hydro's Net Metering program, suggesting that additional efforts may be required to build customer awareness, even among Hydro's own customer base.

Finally, while respondents are unsure how Hydro can improve customer engagement, there is clear interest in engaging with the Utility. Indeed, the majority of respondents expressed interest in joining Hydro's Electricity Feedback Panel.

** The infographic on the following page offers a one-page visual summary of key findings from the 2018 Digital Engagement Initiative.*

2018 Digital Engagement Study

Key Highlights

Methodology: 2,070 online surveys with NL residents
Data Collection: August 28 – September 20, 2018

Current System

82%
Believe they receive ***highly reliable*** electricity (scores 7-10; 10-pt. scale)

Respondents recall experiencing on average **3** power outages each year

With the average outage being ***2.9 hours***

While the majority of respondents feel the frequency of outages is consistent with previous years…

28% Report experiencing ***fewer*** outages

Only* 30%** Of residents are aware of Hydro's ***Net Metering Program

63%
Of respondents are highly interested in signing up for ***Time-of-Use Rates*** *(Scores 7-10; 10-pt. scale)*

Opinions Regarding Electricity Usage & Customer Rate Options…

(% offering high levels of agreement: scores 7-10; 10-pt. scale)

Customers should take an active role in managing their electricity consumption	81%
I would like to better understand my electricity usage any time of day, in real time	77%
There should be more customer rate options so I can better manage my monthly electricity cost	73%
There should be more customer rate options for business owners, so I can better manage my monthly electricity cost	73%

Opinions Regarding Current System and Future Investment…

(% offering high levels of agreement: scores 7-10; 10-pt. scale)

My power reliability has improved since DarkNL	57%
NL needs a more reliable system than it has right now	47%
I am comfortable with our power system's current level of reliability [and] prefer additional investment be made cautiously	71%
Hydro should invest in more generation to further reduce the impact of power supply interruptions during extreme events	31%

Looking to the Future…

Electricity Rate Increases vs. Length of Outage

67% *Of respondents tend to 'prefer **minimal increase on their electricity rate**, and are willing to **accept a risk of longer outages**.*

Preferred Balance: Reliablity vs. Impact on Cost

59%	34%	6%
Good reliability - ***Lower*** impact on cost	***Better*** reliability - ***Moderate*** impact on cost	***Best*** reliability - ***Higher*** impact on cost

57% *Are interested in joining* ***Hydro's Electricity Feedback Panel***

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The following visual depicts the profile of overall survey respondents, including gender, age, household income, home ownership, regional breakdown, and customer type. A comparison to the NL population is also shown for key characteristics.

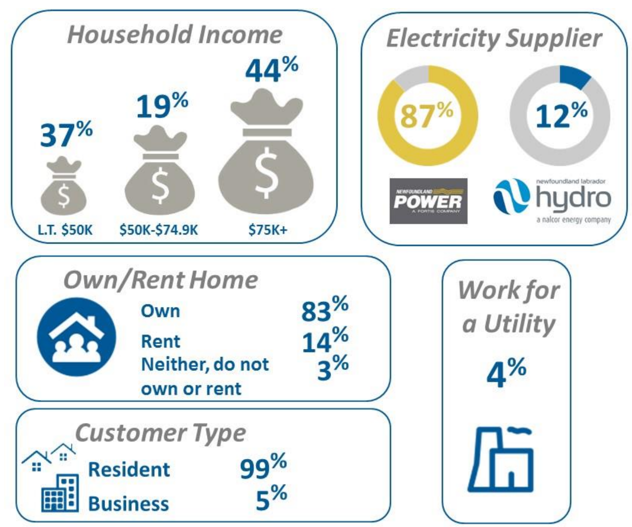
Respondent Profile

- The online study included a robust sample of **2,070** NL respondents. While quotas were not put in place given the mode of data collection (i.e. all residents were invited to visit the site), it is important to note that the actual breakdown of respondents is closely aligned with the true population distribution. As outlined in the following table, the vast majority of survey respondents reside in the eastern region, and most are customers of Newfoundland Power.

- Reflective of the actual demographics in the province, respondents are most likely to be 55 years of age or older. Moreover, the vast majority of respondents overall were home owners. Few businesses were included. (Tables 2, 20-25)

Demographic Characteristics

		2018 Digital Engagement Study (n=2,070)	Actual Population (n=428,955)
Gender	*(% Among valid)*	(n=1,876)	
	Male	54%	48%
	Female	46%	52%
Age	*(% Among valid)*	(n=1,789)	
	18 to 24	2%	9%
	25 to 34	17%	13%
	35 to 44	18%	15%
	45 to 54	20%	19%
	55 to 64	24%	20%
	65 years or over	20%	24%
Region	*(% Among valid)*	(n=2,011)	
	St. Johns /Avalon	59%	52%
	East	13%	18%
	West	28%	31%



Note: Respondents could select both resident & business

Among valid responses (n=1654-2070).

Q.20: **[IF NL RESIDENT IN Q.2]** In what year were you born? *(Recoded into age categories)*
Q.24: **[IF NL RESIDENT IN Q.2]** What is your gender identity?

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Executive Summary | Respondent Profile | **Hydro's Current System** | Reliability & Rates | Customer Options

At the start of the survey, respondents were presented with the first of three informational videos. This initial video provided a brief explanation of the survey's purpose, and overview of the current state of Hydro's electricity system. Note, each video was just over one minute in length.

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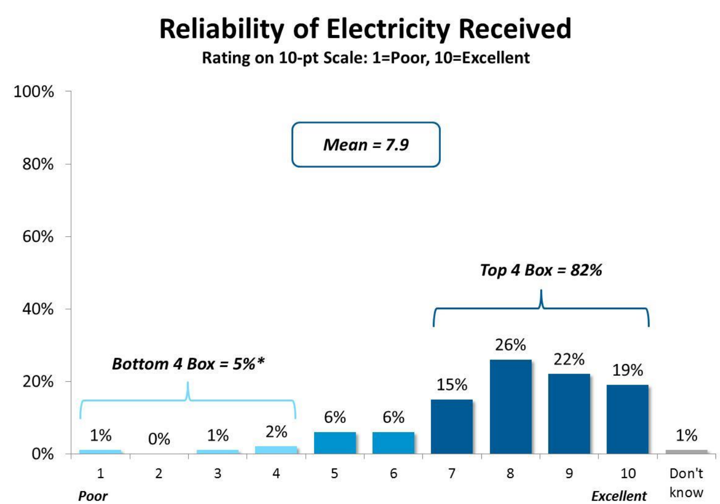
Electricity Reliability

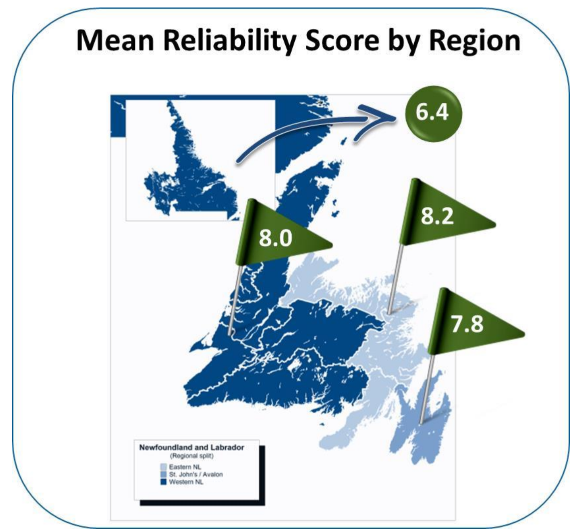
Overall, NL respondents consider their electricity service to be highly reliable.

After viewing the first video, to better understand perceptions regarding overall reliability of NL's electricity system, respondents were asked to rate the reliability of electricity they received using a 10-point scale, whereby '1' means *poor* and '10' means *excellent*.

- ***More than eight in ten respondents report to receive highly reliable electricity service*** (scores of 7-10), while just over one in ten rate give more ***moderate*** reliability scores (scores of 5-6). Conversely, only five percent of respondents consider their electricity reliability to be ***poor*** (scores 1-4).
- Across regions, those residing in Labrador are notably more likely to provide ***moderate scores***, with the average score in Labrador being 6.4 (versus 7.9, overall). (Table 3)



Q.3: How would you rate the reliability of electricity you receive? (n=2070)
Due to rounding. Responses of 'Don't know' have been excluded from the calculation of the mean.



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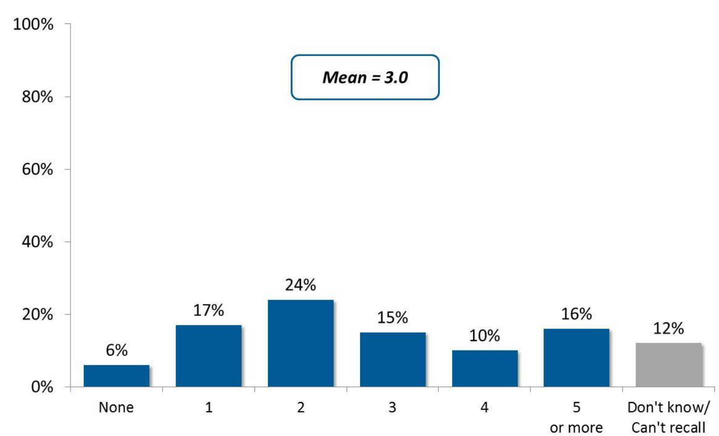
Number of Outages Experienced

On average, respondents report experiencing 3 outages a year.

Respondents were asked to indicate the approximate number of outages they experienced within the past 12 months.

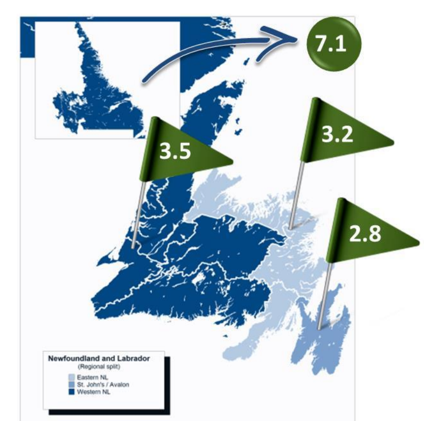
- While few (6%) report having experienced <u>no</u> outages in the past 12 months, more than one-half (56%) of respondents state they experienced one to three outages during this timeframe. At the same time, fewer than two in ten (16%) reportedly experienced five or more outages in the past year. Interestingly, one in ten respondents were unsure or unable to estimate the number of outages they experienced.
- Perhaps unsurprising given noted differences in perceptions related to electricity reliability, there are key differences regarding the frequency of outages based on region and customer type. Indeed, across regions, respondents living in Labrador were notably more likely than respondents overall to have experienced a high number of outages (5+ outages) in the last year (58% vs. 16%), with an average of 7.1 outages being experienced.
- Moreover, Hydro customers experienced a notably higher number of outages on average than NF Power customers (5.1 vs. 2.7 outages). (Table 4)

Number of Outages Experienced Within Past 12 Months



Q.4: Approximately how many outages have you experienced within the past 12 months? (n=2070)
Responses of 'Don't know/Can't recall' have been excluded from the calculation of the mean.

Mean # of Outages by Region



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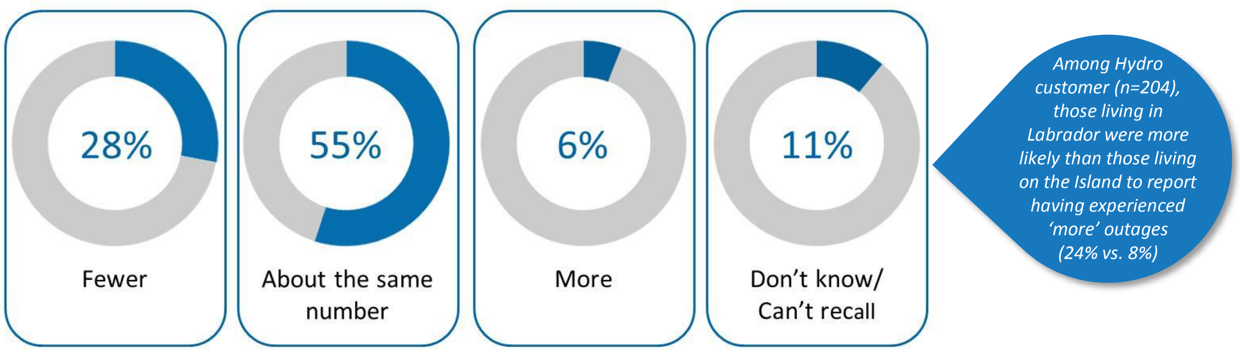
Number of Outages Experienced *(cont.)*

The prevalence of outages experienced is generally perceived to be consistent with previous years.

- When asked to compare the prevalence of outages experienced to previous years, more than one-half of respondents believe the number of outages was in keeping with the past, while more than one-quarter believe they actually experienced ***fewer outages*** this year. Few believe they experienced ***more outages***.
- Across regions, those living in Labrador are more likely to have experienced ***more*** outages (22%) than those living elsewhere in the province.
- At the same time, NF Power customers are more likely than Hydro customers to report experiencing ***fewer*** outages this year (29% vs. 19%). (Table 5)

Outages Experienced Compared to Previous Years



Q.5: Was this fewer, about the same, or more outages than you experienced in previous years? (n=2070)

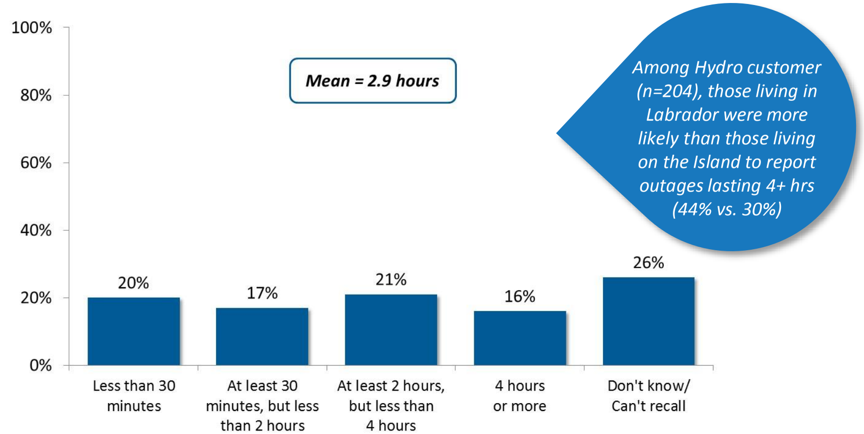
Duration of Outages

Duration of last outage varies notably.

Regardless of when their last outage was, all respondents were asked to approximate the duration of their last outage.

- Overall, the reported outage length varied notably, with the average overall reported length being ***2.9 hours***. That said, it warrants mention that one-quarter of respondents were unable to estimate the length of their last outage.
- Two in ten respondents reported their last outage being ***less than 30 minutes*** in duration, while marginally fewer reported a slightly longer duration of ***30 minutes to up to 2 hours***. Less than two in ten reported their last outage being ***4 hours or more***.
- Across regions, Labradorians reported the longest outages, with the last outage lasting an average of ***5.6 hours***. Moreover, across utilities, Hydro customers reported their last outage was notably longer than NF Power customers' (4.1 hours vs. 2.7 hours). (Table 6)

Length of Last Outage

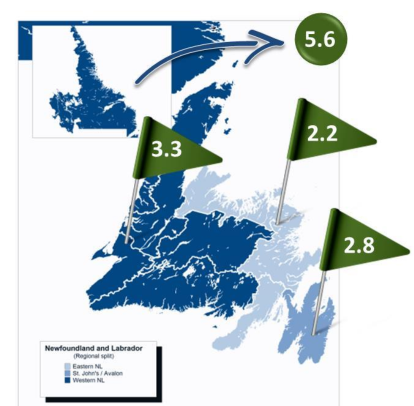


Q.6: On average, how long was your last outage? (n=2070)

Responses of more than 96 hours and 'Don't know/Can't recall' are excluded from the calculation of the mean.

Average Length of Outage by Region

(in hours)



Perceptions of Electricity Reliability

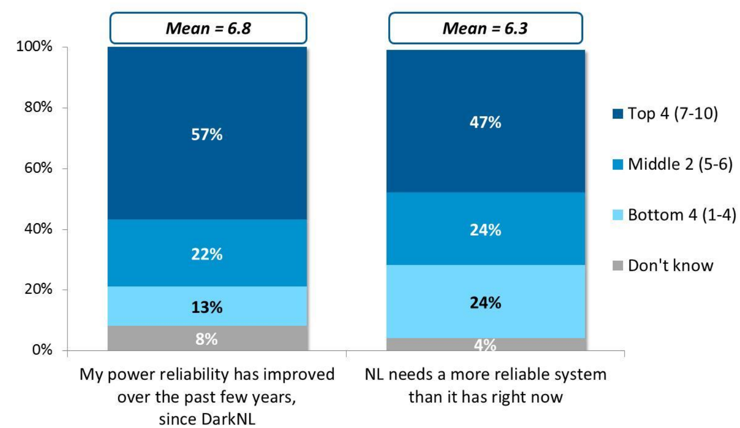
While there is a general perception that power reliability has improved since DarkNL, there are mixed opinions as to whether there is a need for a more reliable system.

In order to further gauge perceptions regarding reliability of NL's current power system, respondents were asked to rate their level of agreement on two separate statements, again using a 10-point scale, whereby '1' is *completely disagree*, and '10' is *completely agree.*

- More than one-half of respondents report high levels of agreement (scores 7-10) that their ***power reliability has improved over the past few years, since DarkNL,*** while just over one in ten disagree with this statement.
- At the same time, opinions are mixed as to whether ***NL needs a more reliable system than it has right now.*** Indeed, while just under one-half of respondents offer high levels of agreement that ***NL needs a more reliable system than it has right now***, one-quarter do not agree that a more reliable system is warranted.
- Labrador respondents are least likely to offer high levels of agreement that their power reliability has improved in recent years (27%), and more likely to offer high agreement that the Province is in need of a more reliable system (65%).
- Interestingly, those employed within the Utilities sector are less likely to highly agree that NL needs a more reliable system (34% vs. 48%). (Tables 7a-b)

Opinion of Statements About Power Reliability

Rating on 10-pt Scale: 1=Completely Disagree, 10=Completely Agree



Q.7a-b: Please indicate to what extent you agree or disagree with each of the following statements. (n=2070)
Responses of 'Don't know' have been excluded from the calculation of the mean.

Younger respondents are more likely to agree that a more reliable system is needed (18-34: 56% vs. 34-54, 55+: 46%)

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Respondents were then asked to view a second video which noted Hydro's ongoing commitment to provide reliable electricity, the impact of weather on power supply, and Hydro's desire to consult with customers regarding the appropriate balance of costs related to investment and electricity rates.

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Perceptions of Investment

Respondents are generally comfortable with NL's current power system and are reluctant to support additional generation investments.

After gauging perceptions regarding the current state of NL's power system, respondents were then asked to rate their level of agreement concerning statements related to future investment, again using the same 10-point agreement scale.

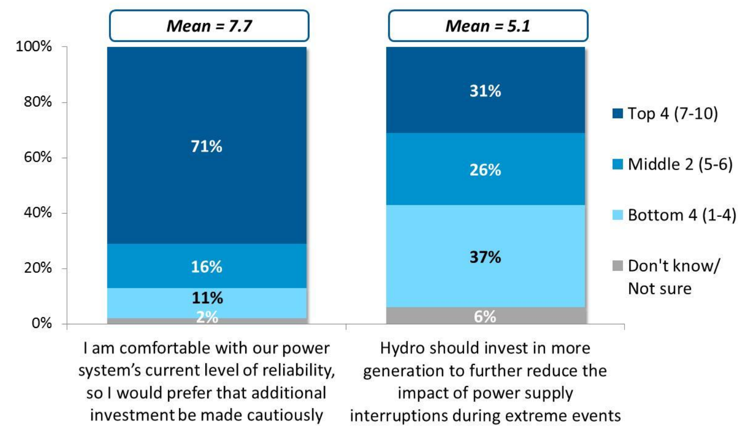
- Overall, the majority of respondents offer high levels of agreement (scores 7-10) that they are ***comfortable with NL's power system's current level of reliability, and as such, would prefer additional investment be made cautiously***. Conversely, only one in ten disagree (scores 1-4) with this statement.

- At the same time, nearly four in ten (37%) respondents disagree (scores 1-4) that ***Hydro should invest in more generation to further reduce the impact of power supply interruptions during extreme events***, while fewer (31%) agree (scores 8-10) that such investment should be made.

- Findings are generally consistent across audience segments, although Labrador respondents are slightly less likely to agree that they are comfortable with the current system, and slightly more likely to agree that Hydro should invest more. (Tables 8A-B)

Opinion of Statements About Investment

Rating on 10-pt Scale: 1=Completely Disagree, 10=Completely Agree



Q.8a-b: Please indicate to what extent you agree or disagree with each of the following statements. (n=2070)
Responses of 'Don't know/Not sure' have been excluded from the calculation of the mean.

Males and higher income earners ($100K+) are slightly less likely to agree that investment is needed

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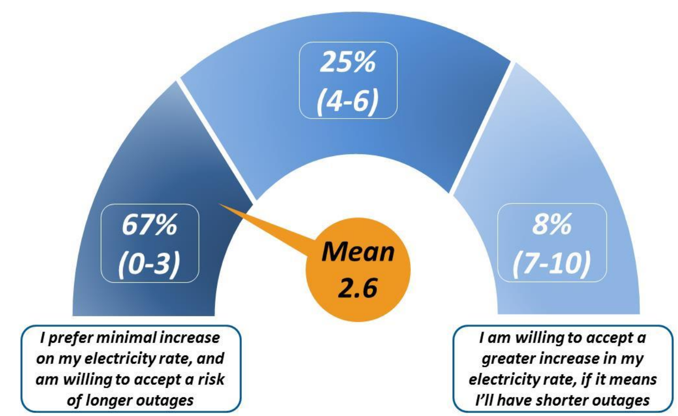
Electricity Rate Increases vs. Outage Duration

Overall, respondents are willing to accept a risk of longer outages, in favour of a minimal rate increase.

Respondents were presented with two opposing statements related to electricity rate increases and outage durations, and asked to position a slider between the two statements to indicate the position that best reflects their personal point of view. *Of note, while the slider was designed similar to an 11-point scale with a mid-point, the related scores (0-10) were not visible to respondents, and are only used in the graph to right to provide a more precise visual of how opinions varied across respondents.*

- Overall, the vast majority of respondents prefer a ***minimal increase on their electricity rates, and are willing to accept a risk of longer outages.*** Indeed, two-thirds of respondents indicated that this statement best reflected their point of view (scores 0-3).
- Few (8%; scores 7-10) reported a ***willingness to accept a greater increase in their electricity rate, if it means they'll have shorter outages,*** while one-quarter of respondents did not feel highly committed to either statement (scores 4-6).
- Across regions, Labrador respondents are more likely to indicate that their point of view falls in between the two statements (scores 4-6: 32%), although the majority still report favouring a minimal increase, and are willing to accept the associated risk (scores 0-3: 58%). (Table 9)

Electricity Rate Increases vs. Length of Outages



Q.9: Please move the slider to a position that best describes your point of view. (n=2070)

Younger respondents are more likely to accept the risk of longer outages in favour of minimal rate increases (scores 0-3: 18-34: 73%, 35-54: 67%, 55+: 64%)

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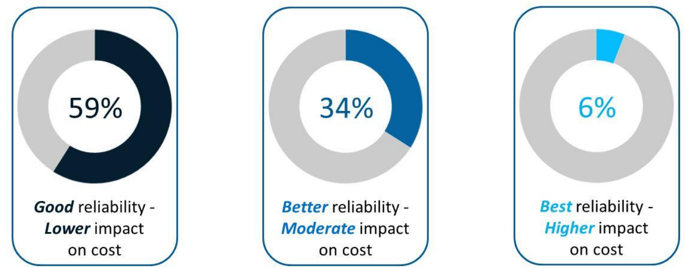
Desired Reliability & Impact on Electricity

There is a clear cost sensitivity when it comes to energy upgrading.

Following a statement regarding the general high cost of upgrading or adding to its supply of power, and the corresponding impact on the price of electricity, respondents were asked to select which of the three alternatives that best describes their preference

- Overall, most respondents favour an approach that involves 'good reliability, with a lower impact on cost'. Indeed, six in ten respondents expressed preference for an investment plan that involves ***good reliability, with a lower impact on electricity cost.***
- Just over one-third of respondents stated they prefer a plan that would provide ***better reliability, with a moderate impact on electricity cost.*** Across regions, Labrador respondents were most likely to favour '***better reliability, moderate impact on cost***' (47%).
- Very few respondents are in favour of an investment strategy that, while offering the ***best reliability***, would mean a ***higher impact on electricity cost***. While those living in Labrador are more likely than respondents overall to prefer this type of approach (13% vs. 6%), it is still the preferred approach by only a minority of those respondents. (Table 10)

Preference: Reliability of Electricity vs. Impact on Cost



Q.10: Please select the alternative that best describes your preference. (n=2070)

Good Reliability, Lower Impact on Electricity Cost: *Hydro should plan to have some back up generation to partially reduce the impact of a sudden loss of power supply.*

Better Reliability, Moderate Impact on Electricity Cost: *Hydro should plan to have additional back up generation to moderately reduce the impact of a sudden loss of power supply.*

Best Reliability, Higher Impact on Electricity Cost: *Hydro should plan to have enough back up generation to significantly reduce the impact of a sudden loss of power supply.*

While older respondents (55+) were more likely than their younger counterparts to express openness to paying more for greater reliability, the majority (53%) still favour 'good reliability, lower impact on cost'.

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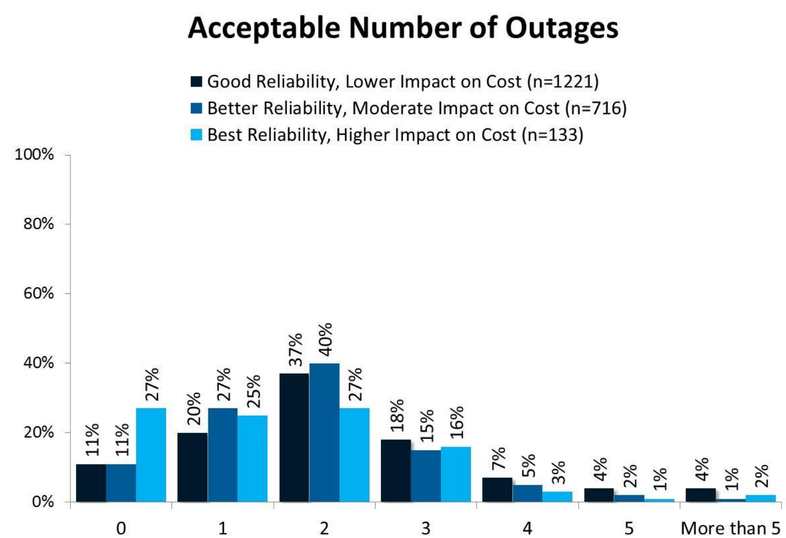
Acceptable Number of Outages

There is a decreased tolerance for outages among those favouring greater investment at a higher impact to cost.

Following respondents preferred selection, they were asked to indicate the number of outages in a given year they would consider acceptable.

- Results show a decreased tolerance for outages with better reliability. As may be expected, those in favour of an investment approach offering the ***best reliability, but with a higher impact on cost*** (n=133) are most likely to consider no amount of outages to be acceptable.
- That said, regardless of respondents' preferred approach, the majority of respondents deem one to two outages to be acceptable, and very few deem more than three outages a year to be acceptable. (Tables 11: Good Reliability, Lower Impact; Better Reliability, Moderate Impact; Best Reliability, Higher Impact)



Q.11: Given an outage caused by loss of supply could last approximately 4-8 hours, how many outages in a given year would you consider acceptable?

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The third and final video shown to respondents noted Hydro's efforts to explore different options to help Newfoundlanders and Labradorians manage their future electricity costs (such as Time-of-Use rates), and asked for their opinions and suggestions on ways they can help customers manage the impact of rising electricity costs.

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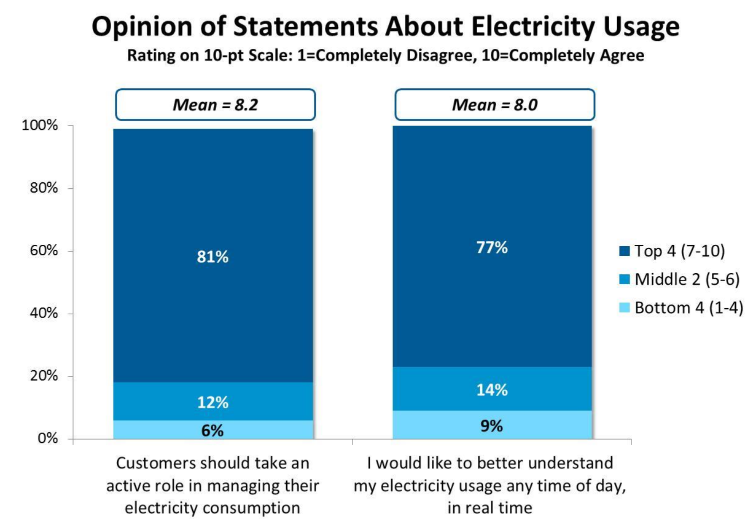
Electricity Usage

Respondents believe consumers should have an active role in managing their electricity consumption and have a clear desire for better understanding their electricity usage.

To better gauge consumer interest in various options aimed at giving customers more choice and control over their electricity consumption, and ultimately how much they pay for it, respondents were asked to rate their level of agreement to two statements, again using the same 10-point agreement scale.

- Eight in ten respondents highly agree (scores 7-10) that ***customers should take an active role in managing their electricity consumption***. Conversely, few disagree with this statement. Of note, those living in Labrador provided a slightly lower score to this statement (average: 7.4).
- Respondents are keenly interested in learning more about their electricity usage, with just over three-quarters of respondents highly agreeing that they would like to ***better understand their electricity usage any time of day, in real time***. (Tables 12A-B)



Q.12a-b: Please indicate to what extent you agree or disagree with each of the following statements. (n=2070)

Agreement that customers should play an active role in managing electricity consumption increases with age and household income

Customer Rate Options

There is a clear interest in having more customer rate options.

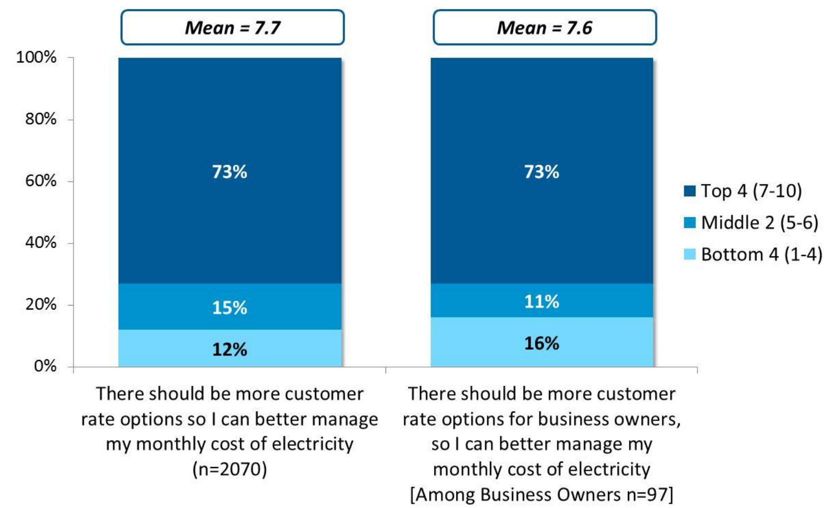
Respondents were asked to rate their level of agreement regarding one or two statements concerning their interest in customer rate options, again using the same 10-point agreement scale.

- Overall, nearly three-quarters of respondents offer high levels of agreement (scores 7-10) that there should be ***more customer rate options so they can better manage their monthly electricity costs***. Conversely, just over one in ten respondents disagree (scores 1-4) with this statement. Overall, interest is generally consistent across audience segments.

- Interest is also strong among NL business owners/operators (n=97). Indeed, as with respondents overall, nearly three-quarters of owners/operators highly agree that ***there should be more customer rate options for business owners, so they can better manage their monthly electricity cost.*** Again, only a minority disagree with this statement. (Tables 13A-B)

Opinion of Statements About Customer Rate Options

Rating on 10-pt Scale: 1=Completely Disagree, 10=Completely Agree



Q.13a-b: Please indicate the extent to which you agree or disagree with the following statement(s) on various options that could be available.

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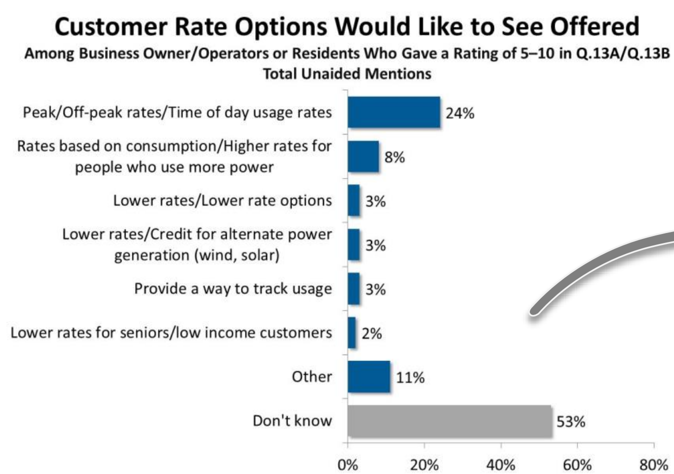
Customer Rate Options *(cont.)*

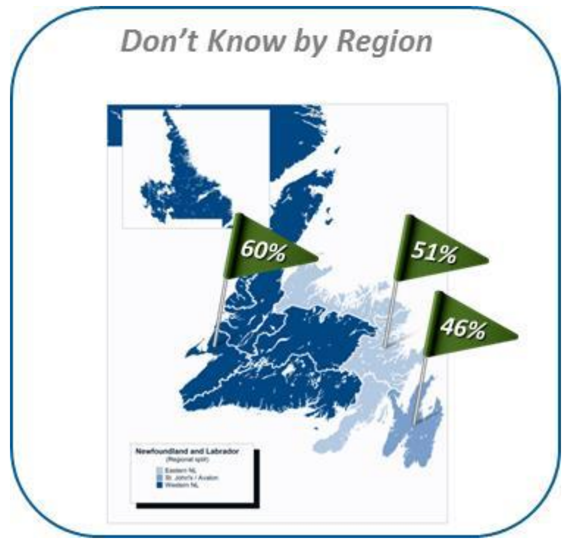
Despite apparent interest in having a more active role in managing their electricity usage, respondents offer limited suggestions as to customer rate options they would like to see offered by Hydro.

Those expressing some level of agreement (scores 5-10) with statements regarding customer rate options (as noted on the previous page), were then asked, unaided, what kinds of customer rate options (or business customer options) they would like to see offered by Hydro.

- Just over one-half of respondents were unable to offer any specific suggestions as to the customer rate options / business customer options they would like to see offered. Of the suggestions that were given, ***Time-of-Day usage rates*** was most popular, with one-quarter of respondents stating they would like to see this added to Hydro's current offerings. At the same time, nearly one in ten suggested ***rates based on consumption, with higher rates for higher users.*** Few alternative suggestions were offered.
- As noted in the below map, those living in the St. John's / Avalon region were most likely to offer some form of suggestion as to the kinds of customer rate options they would like to see added, and were most likely to suggest ***Time-of-Day usage rates*** (St. John's / Avalon: 31% vs. East: 21%, West: 16%). (Table 14)



Q.14: [IF 5-10 IN Q.13A (BUSINESS) OR Q.13B (RESIDENT)] What kinds of customer rate options (or business customer options) would you like to see offered by NL Hydro? (n=500) *Note: Random 500 responses selected for coding.*



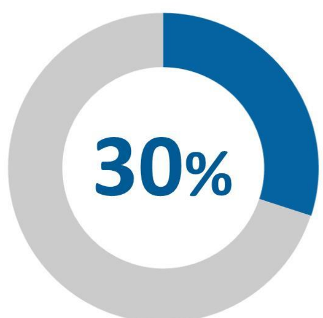
Net Metering Program

There is limited awareness of Hydro's Net Metering Program.

To gauge awareness of Hydro's Net Metering Program, respondents were asked, aided, whether they were aware of the program prior to the survey.

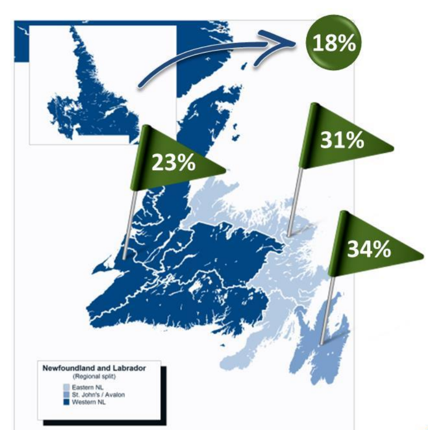
- Fewer than one-third of respondents were aware of the program. As noted in the below map, those residing in Labrador were least likely to be familiar with the program. This finding suggests additional efforts may be required to build customer awareness.
- Men, higher income earners ($100K+), and those under the age of 55 were more likely than their respective counterparts to be familiar with the program.
- As would be expected, those working for a utility were more likely to be aware of the program (67%). (Table 15)

Aware of Metering Program
(% Yes)



Q.15: Hydro has a net metering program which allows customers to generate their own electricity and offset their electricity costs. Were you aware that this program is available for customers? (n=2070)

Awareness of Net Metering Program by Region
(% Yes)



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Interest in Time-of-Use Rates

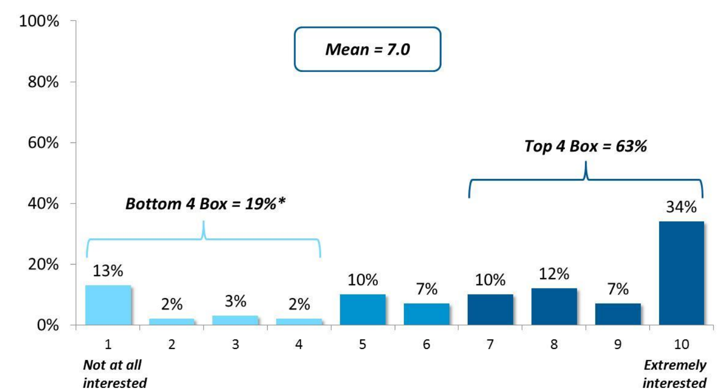
Interest in Time-of-Use Rates is generally strong.

After receiving a brief overview of Time-of-Use rates (as outlined in the video), respondents were asked to rate their level of interest in signing up for Time-of-Use rates and shifting their usage outside of peak morning and evening times in order to reduce their electricity bill. Again, respondents were asked to use a 10-point scale, whereby '1' means *not at all interested* and '10' means *extremely interested*.

- Results show respondents have a clear interest in signing up for Time-of-Use Rates, with nearly two-thirds expressing high levels of interest (scores 7-10). At the same time, just under two in ten express only moderate interest, while a similar portion are uninterested.
- Interest varies across regions, with those living in St. John's / Avalon being most likely to be highly interested (67%), while those living in Labrador are least likely to express this level of interest (55%).
- Of note, Hydro customers are less likely than NF Power customers to express a high level of interest in Time-of-Use rates (51% vs. 65%).
- Finally, it is interesting to note that those with household incomes of less than $50,000 are less likely than more affluent respondents to be highly interested in shifting their usage in order to lower their electricity bill (<$50K: 59% vs. $50-100K: 68% and $100K+: 71%). (Table 16)

Level of Interest in Signing Up for Time of Use Rates

Rating on 10-pt Scale: 1=Not at all Interested, 10=Extremely Interested



Q.16: **[NOT ASKED IF ONLY BUSINESS OWNER/OPERATOR IN Q.2]** With the information you have now, how interested would you be in signing up for Time of Use Rates (that is shifting your usage outside peak morning and evening times), if you knew it could reduce your electricity bill? (n=2050) **Due to rounding.*

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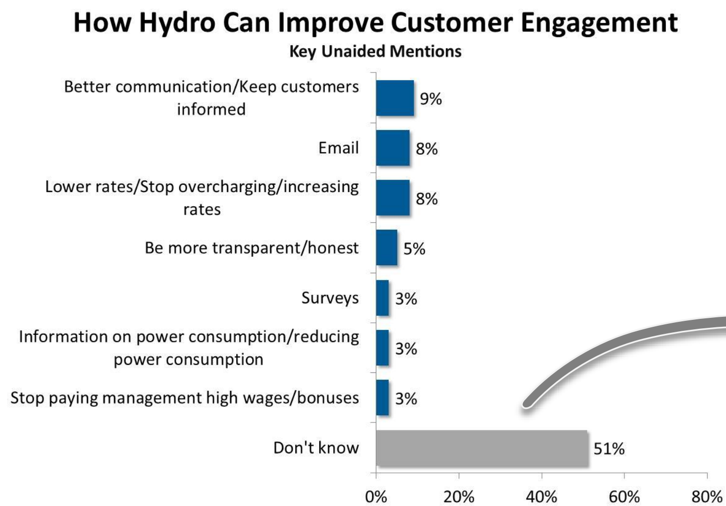
Suggestions on How to Improve Customer Engagement

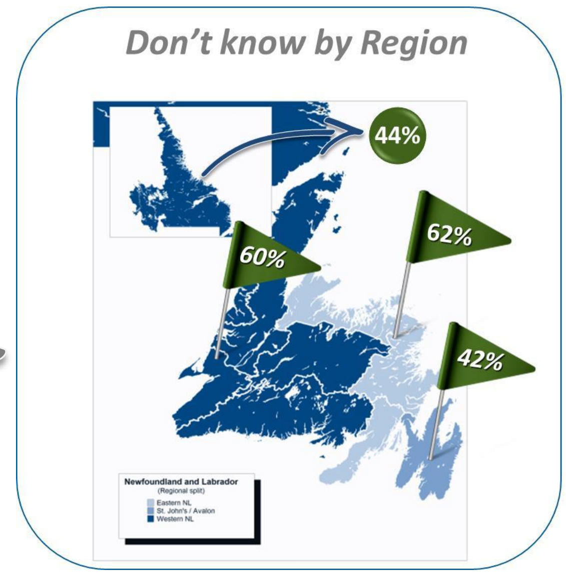
Ways Hydro can improve customer engagement are not readily evident to respondents.

- When asked what Hydro could do to improve customer engagement one-half of respondents were able to provide a response. Of the suggestions that were given, ***better communication/keeping customers informed***, ***lower rates***, and ***email communication*** were each suggested by just under one in ten respondents, while fewer suggested ***being more transparent***, ***providing information on ways to reduce power consumption***, ***surveys***, ***stop paying management high wages/bonuses***, and ***social media***.

- As noted in the below map, those living in the Western and Eastern regions are most likely to be uncertain as to how Hydro can improve customer engagement. (Table 17)



Q.17: How can NL Hydro improve how it engages with you (and its business customers)? (n=500)
Note: Random 500 responses selected for coding.



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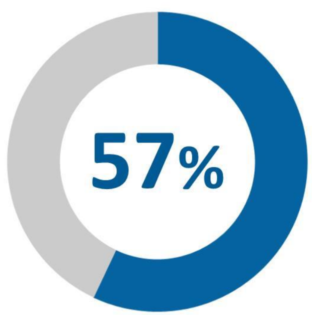
Interest in Joining Hydro's Electricity Feedback Panel

Respondents are generally interested in engaging with the Utility in the future.

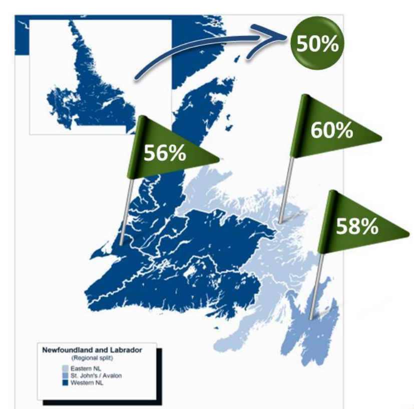
- More than one-half (57% - n=2,070) expressed interest in joining Hydro's electricity feedback panel, and providing feedback via online on various topics or issues.
- Respondents 35 years of age and older are slightly more likely than their younger counterparts to be interest in becoming a panel member (35-54: 63% and 55+: 62% vs. 18-34: 55%).
- Those working within the Utility sector are least likely to want to join the panel (35%).
- Finally, as shown in the regional map, interest in joining the panel is strong across the province. (Table 18)

Interested in Joining Hydro's Electricity Feedback Panel
(% Yes)



Q.18: As NL Hydro continues to plan for the future to continue to meet its mandate of providing safe, reliable and least cost electricity to the province, it's interested in getting continued feedback from consumers. Hydro is building a feedback panel, where you could have the opportunity to provide feedback via online surveys on various topics or issues. Would you be interested in joining Hydro's electricity feedback panel? (n=2070)

Interest in Joining Panel Region
(% Yes)



Attachment 4

Resource Options not under Consideration

Resource Options not Under Consideration

November 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Table of Contents

The following are generation alternatives that were reviewed and not considered for potential use in the generation resource plans. A summary of each of those alternatives and why they were screened out of the analysis follows.

1 Labrador Generation

Gull Island is a 2,250 MW hydroelectric generation project on the Churchill River with an average annual energy capability of 11.9 TWh. Located 225 kilometres downstream from the existing Churchill Falls Power Plant, Gull Island has been extensively studied over the years and the engineering work completed has led to a high level of confidence in the planned design and optimization of the facility. However, the scale of Gull Island output creates a requirement to either negotiate with neighbouring utilities for export contracts, attract investments in energy intensive industries, or to participate directly in regional wholesale markets to attain the full utilization unit cost; otherwise island supply is the only available market. At this time, the energy output of the facility is materially higher than the load growth demand of the province for the foreseeable future. Further, due to the limited capacity of the Labrador-Island Link, getting the energy to the island would be a constraint and thus not economically desirable.

Therefore, the expansion option of the Gull Island Hydroelectric Development is not considered at this time, given the projected load growth in the province.

2 Natural Gas

Natural gas is used as a fuel source for combustion turbines and combined cycle combustion turbines throughout the industry. Technology exists to reconfigure a heavy oil-fired facility such as the Holyrood Thermal Generating Station (“HTGS”) to burn natural gas. A range of natural gas configurations including modification of the HTGS to burn natural gas, and replacement of the HTGS with new high efficiency combined cycle gas turbines had previously been evaluated as part of the Muskrat Falls decision process.

Significant barriers and risks associated with the integration of natural gas as a resource option remain, the most significant of which is the infrastructure required to facilitate the delivery of natural gas to be used in electricity generation. Given the lack of a confirmed development plan for provincial natural gas and the current system requirements, domestic natural gas has not been considered as a supply option.

3 Liquefied Natural Gas

Liquefied natural gas is natural gas that has been cooled to about minus 163°C for shipment and/or storage as a liquid. The volume of the gas in its liquid state is about 600 times less than in its gaseous form. In this compact form, natural gas can be shipped in special tankers to receiving terminals. At these terminals, the liquefied natural gas is returned to a gaseous form and transported by pipeline to distribution companies, industrial consumers, and power plants. A key challenge to any scenario for natural gas-fired power generation in Newfoundland is the small market. Currently, Newfoundland and Labrador has no industrial base for use of natural gas. Neither is there a large readily available residential market for distributed natural gas. As a result, for natural gas to be considered as a resource option, costs associated with regasification, including the construction and operation of a terminal, must be considered. Given the current system requirements, liquefied natural gas has not been considered as a resource option.

4 Nuclear

A nuclear reactor uses controlled nuclear reactions to produce heat energy. The heat energy is then used to produce steam. The steam is used to turn a steam turbine, which turns an electric generator to produce electricity. As nuclear plants typically operate at a base load with little change in output, it would be challenging to integrate a nuclear facility in the Newfoundland and Labrador Interconnected System (“NLIS”), given the fluctuation in system load shape.

While modular reactors do exist, the majority of existing designs are large facilities, with sizes greatly exceeding the NLIS minimum demand.

Beyond operational issues for the Island Interconnected System, there are issues around the safe, long-term storage of nuclear waste associated with nuclear generation.

While nuclear generation has been deployed in many countries around the world, from a public policy perspective, the *Electrical Power Control Act, 1994* prohibits the construction and operation of nuclear power plants in Newfoundland and Labrador.

Given that nuclear generation is currently prevented by provincial legislation and would be challenging to integrate into the NLIS, nuclear generation was not considered as a resource option.

5 Coal

Coal-fired electric generation draws its fuel from vast reserves of non-renewable, naturally occurring deposits of coal. Coal reserves are mined, processed, and transported to the generation site where they are pulverized and fed into a boiler to generate heat energy. The heat energy is used to produce steam. The steam is used to power a turbine which turns an electric generator.

While coal continues to be used for electricity generation in Canada increasing regulation, including the introduction of carbon pricing, pose a significant risk in pursuing coal-fired generation as a resource option. As such, coal-fired generation was not considered as a resource option.

6 Biomass

Biomass energy is derived from many different types of recently living organic matter (feedstock). However, in the context of producing large-scale energy, it is likely that the focus would be on harvesting forestry products as fuel for the biomass generator. Biomass works similar to many other thermally-based generators in that wood or other biomass products are harvested, treated and then transported to the generation plant to be used in place of other solid fuels such as coal to generate heat. The heat is then used to produce steam. The steam is in turn fed into a turbine that turns a generator to produce electricity.

Due to the requirement to harvest a large and steady supply of forestry products, manage and maintain the sustainability of the forest harvest, and transportation costs in getting the harvested material to the generation site, the unit costs for energy from biomass plants is usually much higher than other forms of energy.

While biomass and other cogeneration alternatives, when economically feasible, will be considered as future supply alternatives, they are not considered to be appropriate alternatives for large-scale resource requirements due to the significant costs and risks around securing significant supply of feedstock. On this basis, biomass not considered as a resource option.

7 Wave and Tidal

Harnessing energy from the natural motion of the ocean currents and waves has long been considered and studied as a viable option for renewable energy production. Many different technologies have been proposed to approach the problem of extracting the wave and tidal energy to produce electricity.

Wave energy technologies work by using the movement of ocean surface waves to generate electricity. Kinetic energy exists in the moving waves of the ocean. That energy can be used to power a turbine. One type of wave generator uses the up and down motion of the wave to power a piston, which moves up and down inside a cylinder. The movement of the piston is used to turn an electrical generator.

Tidal power is based on extracting energy from tidal movements and the water currents that accompany the rise and fall of the tide. When the tide rises, the water can be trapped in a reservoir behind a dam. Then when the tide falls, the water behind the dam can be released through a turbine similar to a regular hydroelectric power plant.

Despite some limited successes, neither tidal nor wave power has become a commercial mainstream source of renewable energy. On this basis, neither wave nor tidal energy considered as a resource option.

Attachment 5

Wind Generation Alternative

NEW COLLIERS LTD.

NL Hydro Wind Generation Alternative

Project Development Estimate

November 3, 2018

Revision 1 – For Client Use

To: Alex Guilbeault, Newfoundland & Labrador Hydro

From: Laurie Murphy, New Colliers Ltd.

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1 Scope

1.1 What is being considered

New Colliers Ltd. (New Colliers) has been engaged by Newfoundland and Labrador Hydro (NL Hydro) to provide support in the feasibility assessment and preliminary cost estimation for the development of small and large-scale wind projects on the island of Newfoundland.

This document describes the basis for a preliminary cost estimate for the following variations of wind projects on the island of Newfoundland:

- Project A: A 100.8MW wind project interconnected to the 138kV transmission system
- Project B: A 12.6MW wind project connected to the 25kV distribution system.

NL Hydro indicated that the estimates should be based on Vestas wind turbine generators (WTGs) as Vestas turbines are already installed at the Fermeuse and St. Lawrence wind projects. The 3MW V90 Vestas turbines installed at Fermeuse and St. Lawrence are no longer commonly marketed by Vestas and Vestas has recommended using the 4.2MW V136 as the basis for this estimate exercise. In general, the trend in the wind industry is a push to larger WTGs with larger rotor-swept diameters to lower project capital expenditures (CapEx) and to increase project capacity factors.

1.2 Notable Omissions

The estimates attached as Appendices A&B include detailed breakdowns for the CapEx costs (also generally referred to as “construction costs” by NL Hydro). The estimate generally encompasses development, procurement, construction and commissioning costs.

No legal fees or costs associated with financing have been allowed for. No contingency has been included in these estimates.

2 Basis of Estimate

This is a preliminary, Class 5 cost estimate. The intent of this estimate is to assess the feasibility and high-level cost of wind project development in Newfoundland based on 2018 conditions.

The preliminary cost estimate is primarily based on experience with industry-normal costs from across Canada along with adjustments made for considerations of NL's specific development and construction environment.

Project Variants

Project A consists of twenty-four (24) 4.2MW turbines:

- With a primarily overhead 34.5kV collection system, as well as underground cable connecting turbines to riser poles, as required
- Connected to the grid through a 138/34.5kV project substation as depicted in Appendix C

Project B consists of three (3) 4.2MW turbines:

- With a primarily overhead 24.9kV collection system, with underground cable connecting turbines to riser poles, as required
- Connected to the grid through a 24.9kV recloser as depicted in Appendix D

Development

The following development costs have been allowed for in the project estimate:

- Installation of two 60m tilt-up meteorological towers
- Development of a Wind Resource Assessment (WRA)
- A limited geotechnical investigation to sufficiently characterize the geotechnical conditions at site to allow for most competitive bidding by contractors and suppliers. A more detailed geotechnical investigation is envisioned to be undertaken by the Contractor in the construction phase
- A limited site survey of key features, as required
- An allowance for land acquisition costs to the extent required for site investigative purposes

- Interconnection System Impact Study (SIS), Facility Study and applicable interconnection fee required to mobilize utility crews for required system upgrades
- An environmental impact assessment
- The internal costs associated with undertaking competitive bid processes for turbine supply, construction contracting and competitive Power Purchase Agreement (PPA) pricing
- Internal engineering and management costs
- Owner's construction site representation
- Land rental costs during construction
- Development permits

Turbine Supply and Delivery

Turbines will be supplied and delivered to the respective turbine pads, where turbine foundations and crane pads are assumed to have been constructed in advance. Costs for delivery, SCADA system and cold weather package are included.

Project Construction

Each project estimate includes the following scope:

- Turbines will have a hub height of 105m
- An overhead/underground collection system with the necessary communications, protection and control
- Construction of access roads, crane pads and wind turbine foundations
- No simulations or studies have been completed to size the DVAR system and capacitor banks. An allowance of $500,000 was included in the estimate to account for VAR compensation equipment and the associated control system
- Testing of collection system, substation and transmission line are included
- Erection of the wind turbine tower sections, nacelles and blades during lower wind months
- Installation and wiring of the substation electrical equipment at the project substation, project ring bus station and/or distribution point of interconnection (POI), as required
- Pre-commissioning and commissioning of turbine systems and balance-of-plant (BOP) systems
- Labour is competitively sourced
- Infrastructure for any future expansion is not included
- The estimate is based on July 2018 dollars (CAD$)

- WTG component receiving location assumed to be at each respective turbine pad
- No allowance for excess material to be hauled off-site has been included
- No rock hammering or blasting has been allowed for. It is assumed an excavator will be able to rip any rock during excavation
- The collection system will utilize underground cable trenches from the turbines to riser pole tie-ins at road allowances and overhead lines generally along road allowances. Two collection system crossings were considered for Project A and one for Project B
- Roads and collection system cable lengths are approximate and are based on typical turbine separations
- Taxes and duties are not included
- Costs of copper, steel, aluminum, concrete and labour may fluctuate and affect the accuracy of this estimate
- It is assumed that the developer will enter into a single design-build contract for all the balance-of-plant (BOP) facilities (i.e. the balance of all infrastructure outside of the WTGs)
- High level estimates of Owner development costs are included
- Contingency is not included and should be applied at the discretion of NL Hydro

More detailed notes on the construction estimate basis is included as Appendix E.

Relevant Notes on Estimates

The wind power industry has seen dramatically reduced energy sale bid prices in recent years, with recent winning bids in Alberta coming in at less than $40/MWh. New Colliers believes that the key driver in facilitating these low bid prices is having a larger plan for competitive bidding between prospective Independent Power Producers (IPPs).

In Alberta, a plan was communicated to stakeholders to provide a roadmap for large scale procurement of wind and solar in the coming years. Turbine suppliers, contractors and other suppliers recognized the potential long-term opportunities in Alberta and were quite aggressive in pricing to build experience, credentials, scale and future opportunities in Alberta.

The historical pricing on which New Colliers has based their estimates has been delivered through competitive bid processes of sufficient size to attract a critical mass of interested, qualified and competitive bidders. New Colliers notes that NL Hydro would be best able to achieve the costs estimated herein by establishing the guidelines of a competitive bidding process sufficiently far in advance to allow for investment in timely project development and competitive procurement processes.

3 Technical

3.1 Location

NL Hydro has not nominated any specific sites for consideration. However, given the wind resource on NL (see Figure 2) and the relatively sparse population, there is a multitude of wind project sites that would feasible for development. Thus, New Colliers has based the estimate on representative sites with the following characteristics:

- within 7km of a highway or major road with site access through existing logging roads or similar for Project A
- within 2km of a highway or major road with site access through existing logging roads or similar for Project B
- within 5km of an existing 138kV transmission line for Project A
- with 2km of an existing 3-phase 25kV distribution line for Project B
- wooded project area without wetlands or shallow bedrock within the construction disturbance footprint
- with turbine components delivered to a port where road upgrades (such as increased turning radii or adjusted vertical curvature) are not required to offload and deliver turbine components to site access points
- on available private or public lands subject to required consultation and approvals

The representative projects are assumed to be on the island of Newfoundland, but projects are likely just as feasible in Labrador.

3.2 Size of Units

As discussed, the Vestas 4.2MW V136 has been used as the basis for this estimate. The brochure for the turbine is attached as Appendix E. In practice, the model for the turbine will be the competitively offered turbine model that provides the most attractive and reliable economics over the life of the project in consideration of capital cost, project-specific yield performance, forecasted project lifetime and forecasted project Operations and Maintenance (O&M) costs.

3.3 Characteristics

3.3.1 Efficiency

The capacity factor for both project variants is estimated to be 40%. Despite NL Hydro's best efforts, no turbine power curve was available for the V136 at the time of preparation of this estimate. As such, New Colliers has estimated a gross per-turbine yield of 18GWh/year based on the following figures:

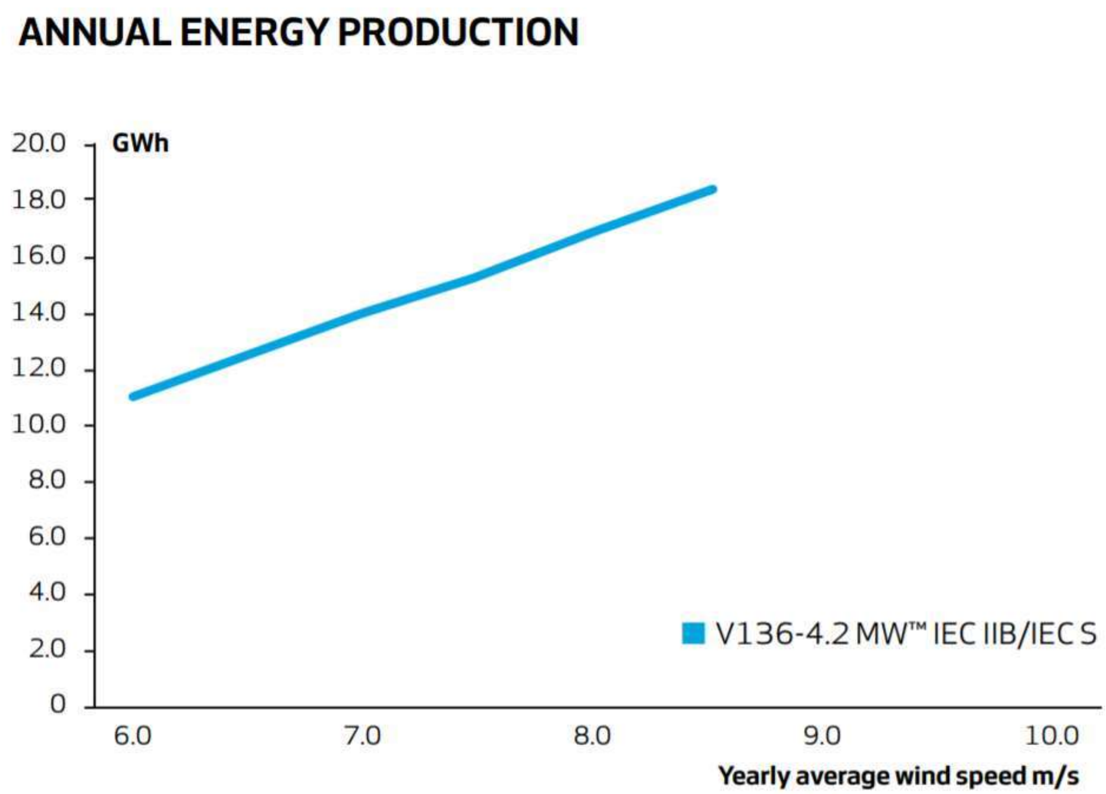


Figure 1: Vestas Estimated Annual Energy Production (courtesy Vestas brochure)

Vestas estimates the gross energy yield for a 4.2MW V136 to be approximately 18GWh on a site with a yearly average wind speed of approximately 8.5m/s. As evidenced by the following figure, Newfoundland has an abundance of sites with at least an 8.5m/s average annual wind speed.

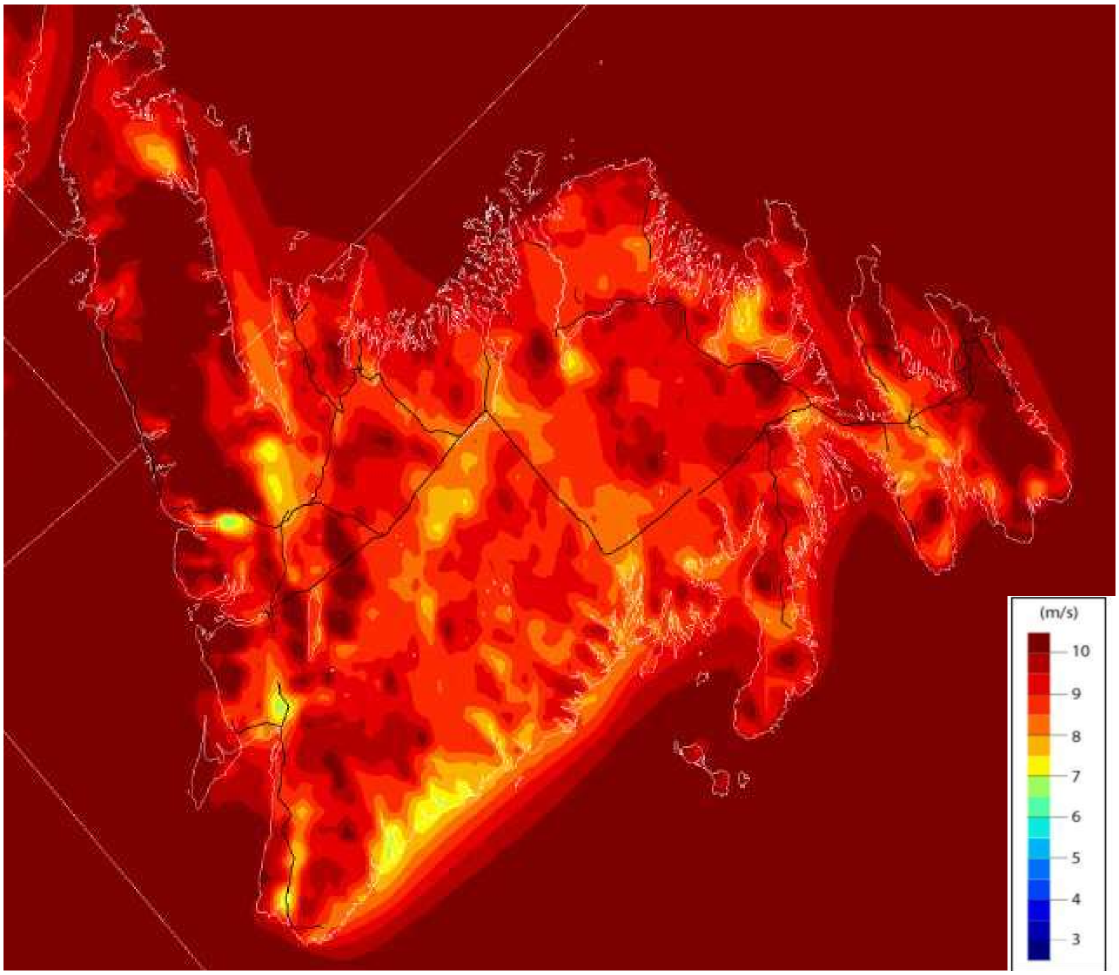


Figure 2: Estimated average annual wind speed at 80m hub height (courtesy www.windatlas.ca)

Based on the data in the preceding figures, 18GWh per turbine may be a conservative energy projection because there are many sites with average wind speeds in excess of the 8.5m/s basis and the Wind Atlas tool estimates wind speeds at 80m hub height. The hub height of our base turbine is 105m, based on Vestas feedback, and the average wind speeds will be higher with this hub height.

It should be mentioned that the turbine selection process must take into consideration many factors. Most notable is that the V136 has a standard suitability for IEC Class IIB sites. The good wind sites in NL may be Class IIA, IA or IB. This may mean that the V136 is ultimately unsuitable for the site. However, comparable cost/yield benefits are likely available from other turbine models should the V136 prove to be unsuitable.

For example, Class IA/IB machines maybe be suitable for some of the sites with average wind speeds in the 9-10m/s average wind speed range and may provide comparable, or possibly even higher, yields.

Another potential benefit that may be explored is putting a smaller rotor diameter machine on a shorter tower in an especially windy site to realize the high yields estimated here while reducing turbine transportation, erection and completion costs.

Selection of the V136, on Vestas' recommendation, as the base model for this estimate is suitable for Class 5 accuracy. The cost/benefit and performance assessment of a selection of potential turbine models and variants should be further investigated in a subsequent phase of study.

New Colliers further refined the net capacity factor estimate by applying approximately 18% losses to the gross energy projection to allow for losses due to:

- project wake effects
- turbine and grid availability
- electrical losses
- potential sub-optimal performance
- environmental losses such as soiling and icing

Based on industry experience, New Colliers believes that a 40% capacity factor is a reasonable estimate for a NL wind project and believes there may be significant opportunity to make use of NL's strong wind resource and advancing turbine technologies to improve the capacity factor beyond 40% and/or reduce construction costs by using lower hub heights.

4 Cost and Schedule

4.1 Capital Cost

Detailed project cost estimates can be found in Appendices A and B. The following cost summaries are reflective of a 4-year development schedule for Project A and a 3-year development schedule for Project B.

Project A:

Cost Centre	Year 1	Year 2	Year 3	Year 4	Cost Centre Subtotals
Owner/Development Activities	$605,000	$1,205,000	$1,280,000	$1,130,000	$4,220,000
Turbine Supply			$22,680,000	$90,720,000	$113,400,000
BOP Construction and Commissioning			$29,396,833	$42,297,067	$71,693,900
Annual Subtotals	*$605,000*	*$1,205,000*	*$53,356,833*	*$134,147,067*	
				Project Cost	**$189,313,900**
				Project Cost per MW	**$1,878,114**

Project B:

Cost Centre	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Cost Centre Subtotals**
Owner/Development Activities	$364,250	$680,750	$585,000	$0	$1,630,000
Turbine Supply		$3,528,000	$14,112,000	$0	$17,640,000
BOP Construction and Commissioning			$9,726,620	$0	$9,726,620
Annual Subtotals	*$364,250*	*$4,208,750*	*$24,423,620*	*$0*	
				Project Cost	**$28,996,620**
				Project Cost per MW	**$2,301,319**

4.2 Construction Schedule

For both Project A and Project B, there is likely a two-year window required to complete key development activities. Developers will erect meteorological towers at the beginning of the two-year window and will need to collect at least one year's worth of data to produce a financeable wind resource assessment.

Developers will engage with stakeholders and conduct an environmental assessment based on a preliminary wind farm layout. Developers and the interconnecting utility will conduct a system impact study in year 1 and facility study in year 2 to assess the impact, cost and system modifications associated with interconnecting the new wind farm generating facility.

Preliminary geotechnical work and preliminary project designs will be completed to sufficiently inform a design-build bid package that will serve as the basis for a competitive and thorough contract procurement process.

Turbine down-payments will be made to initiate the turbine supply process in year 3 for Project A and year 2 for Project B.

In year 3, construction activities will commence,

The larger Project A would likely require two years for actual construction activities while the smaller Project B could likely be completed in a single construction year.

For Project A, engineering activities would begin for civil works and foundations in January of year 3. Road construction and civil works would begin as early as possible in the spring of year 3. Over the course of year 3, project roads and major grading activities would be completed, and foundations would be poured for all turbine, substation and ring bus station foundations.

In year 4, turbine, substation and ring bus station equipment would be delivered, assembled and commissioned with a target commercial operation date (COD) of December, year 4.

For Project B, all engineering and construction works for the civil, structural and electrical work can occur in year 3 with a target COD of December, year 3.

4.3 O&M costs

It is expected that the project will have turbine maintenance work performed by the turbine supplier/original equipment manufacturer (OEM) for the first two to five years. After that, it is expected that the developer will undertake the turbine maintenance with some combination of self-performing the work and engaging with turbine OEM and/or wind turbine maintenance independent service providers (ISPs) for planned, unplanned and major maintenance works.

Further, it is expected the developer will manage turbine maintenance contracts, substation and collection system maintenance contracts and road maintenance contracts with a key project representative.

In addition to pure maintenance costs, developers will also have ongoing land lease costs to operate the project.

Based on industry experience, New Colliers believes that all these O&M activities can be completed for approximately $60,000/MW per year in 2018 dollars. These costs are most likely achievable if the successful turbine supplier can establish, or sees the prospect of establishing, a critical mass of operations to efficiently and cost effectively conduct current and future prospective business. As mentioned previously, implementing a larger wind power development strategy will allow for most competitive pricing for O&M services.

4.4 Environmental

Wind turbines produce emissions-free energy over the operational life of the project and also impact a relatively small footprint during the construction phase. As such, wind projects generally enjoy good levels of public acceptance and have relatively few environmental impacts and risks. Environmental assessment processes most commonly address the following key considerations:

- Noise emissions
- Visual impacts
- Bird and bat mortality
- Disturbance of wetlands or other key habitat

Proper siting of turbines early in the development phase can typically reduce impacts associated with the above concerns and generally reduce the associated development and operational risks.

5 Feasibility

The wind power industry is now quite mature in Canada. Technological advancements, operational experience and industry competition have given way to one of the cheapest new generation alternatives available.

Key development risks often include:

- Adequacy of wind resource
- Access to suitable and publicly-acceptable land for the project
- Access to injection points on the grid that can accommodate generation with modest system upgrades and that are also close to windy project locations
- Site access for turbine component delivery
- Site conditions that result in non-standard construction methods

- Increased costs associated with mitigating any of the impediments identified above

In general, New Colliers believes that there is an abundance of high potential wind project sites in Newfoundland. The wind resource in Newfoundland is especially strong and it is expected that there will be plenty of available public and/or private land near transmission and distribution injection points that will also have acceptable wind resource.

Thus, it is expected that the key risks for wind project development are related to the potential for high costs associated with construction and operation of the wind project. As discussed previously, turbine suppliers, especially, are more likely to invest time and resources in pursuing a market if they believe there is potential for several projects to be built over time.

If turbine suppliers believe they have a reasonable opportunity to be successful in one or more projects, they are more likely to provide more aggressive pricing for turbine supply and turbine maintenance to establish scale in the area. The lowest OEM maintenance costs are going to be available from a supplier that has a critical mass of operations in a region. Developing only a small number of projects may produce higher O&M costs than estimated herein. And so, any procurement of wind energy needs to be carefully planned and executed to obtain best pricing.

The costs estimated for the 12.6MW distribution project are especially sensitive to having a critical mass of turbine OEMs bidding to supply turbines and provide turbine O&M services to multiple wind projects. The estimated costs for the distribution-interconnected option may not be realized with procurement of a single small wind project.

Construction costs also have a relatively high risk for increase for Newfoundland wind projects. It is expected that the following construction components have the highest potential for higher-than-estimated costs:

1) Possibility of sites having shallow rock that would increase costs for turbine foundation, road and collection system construction. The estimates developed by New Colliers assume that standard excavation techniques will suffice, with rock that can be ripped without needing to hammer or blast
2) Potential for the costs associated with importing and renting large cranes for turbine erection to be higher than expected
3) Potential for labour costs to be higher than anticipated – There will likely be a limited amount of qualified prime contractors locally to complete key construction activities such as turbine erection and substation construction. Given this, developers will likely need to import

experienced contractors from other parts of North America to manage the project and take construction risk. Prime contractors will likely use local subcontractors where competitively priced. The resulting labour costs are not well known for this type of construction in Newfoundland.

Despite these project risks, New Colliers expects that new wind project developments in Newfoundland have a high potential for success if properly managed and executed. Additional wind generation capacity would pair well with Newfoundland's already strong hydro resource. The abundant hydro resource can likely balance the variability of a substantial wind portfolio size.

And so, development of what should be some of the most productive wind projects in North America would provide Newfoundland with an opportunity to:

- Diversify the local electricity fuel supply with a relatively non-contentious renewable fuel source
- Provide additional renewable energy export capacity
- For the distribution-connected option, lessen loads on distribution feeders and reduce the need for distribution feeder upgrades should technologies, such as electric cars, drive future load growth. This approach could be especially effective when paired with local energy storage.
- For the distribution-connected option, create resilient regional microgrids, when paired with storage, to provide a more resilient distribution system

Lawrence Murphy
LM:lm

Appendix A: 100.8 MW Estimate
Appendix B: 12.6 MW Estimate
Appendix C: Transmission SLDs
Appendix D: Distribution SLD
Appendix E: Vestas 4.2MW V136 WTG Brochure
Appendix F: Detailed Construction Estimate Assumptions
Appendix G: NL Hydro Summary Tables

Appendix A

100.8 MW Estimate

NEW COLLIERS LTD.

Preliminary Project Development and Construction Estimate
07-Aug-18

Site	**Newfoundland representative site**	
Number of WTG	**24**	
Turbine type	**Vestas V136**	
Size of turbine	**4.2**	MW
Size of project in MW	**100.8**	MW

Total Costs

	Year 1	Year 2	Year 3	Year 4	Cost
Owner/Development Activities	$605,000	$1,205,000	$1,280,000	$1,130,000	$4,220,000
Turbine Supply			$22,680,000	$90,720,000	$113,400,000
BOP Construction and Commissioning			$29,396,833	$42,297,067	$71,693,900
Annual Subtotals	*$605,000*	*$1,205,000*	*$53,356,833*	*$134,147,067*	
				Project Cost	**$189,313,900**
				Project Cost per MW	**$1,878,114**

Owner/Development Activities

	Year 1	Year 2	Year 3	Year 4	Cost
Met tower deployment 2 towers	$200,000	$0			$200,000
WRA analysis for 1 year, WRA reports	$30,000	$120,000			$150,000
Site surveying, limited boreholes w/ desktop geotechnical study	$7,500	$42,500			$50,000
Stakeholder consultation/engagement	$125,000	$125,000			$250,000
Land acquisition	$0	$100,000			$100,000
Interconnection studies, application and agreement	$37,500	$212,500			$250,000
Interconnection fee	$0		$500,000		$500,000
Environmental Impact Assessment	$75,000	$175,000			$250,000
Project contract procurement and PPA pricing	$100,000	$400,000			$500,000
Inhouse engineering, project management and oversight	$30,000	$30,000	$240,000	$240,000	$540,000
Construction management	$0	$0	$240,000	$440,000	$680,000
Land rental during construction	$0	$0	$250,000	$250,000	$500,000
Permits and licenses	$0	$0	$50,000	$200,000	$250,000
Annual Subtotals	*$605,000*	*$1,205,000*	*$1,280,000*	*$1,130,000*	
				Development Cost	$4,220,000
				Development Cost per MW	$41,865.08

Turbine Supply, Delivery and Commissioning

	Year 3	Year 4	Cost
24 Vestas V136 4.2MW turbines	$22,680,000	$90,720,000	$113,400,000
		Turbine Cost	**$113,400,000**
		Turbine Cost per MW	**$1,125,000**

Balance-of-Plant (BOP) Construction Estimate

			V136	
Construct WTG Sites and Crane Pads				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Wood Cutting and Grubbing	24	Turbine	$ 9,000.00	$ 216,000.00
Excavation, backfill and crane pad prep	24	Turbine	$ 44,000.00	$ 1,056,000.00
WTG Sites Reclamation	24	Turbine	$ 3,850.00	$ 92,400.00
			Subtotal	$ 1,364,400.00
Construct Laydown and Trailer Area				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Excavate and Backfill Trailer Area	1	each	$ 130,000.00	$ 130,000.00
Excavate and Backfill Concrete Batch Plant Area	1	each	$ 130,000.00	$ 130,000.00
Reclamation of Temporary Area	1	LS	$ 100,000.00	$ 100,000.00
			Subtotal	$ 360,000.00
Improve Existing Roads				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Improve Existing Roads	7000	m	$ 82.50	$ 577,500.00
Allowance for improved major approaches	6	each	$ 55,000.00	$330,000.00
			Subtotal	$ 907,500.00
Construct New Roads and Drainage				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Wood Cutting and Grubbing	68	Ha	$ 9,000.00	$ 612,000.00
Construct new roads	34000	m	$ 176.00	$ 5,984,000.00
Roads maintenance and reclamation	34000	m	$ 49.50	$ 1,683,000.00
			Subtotal	$ 8,279,000.00
Foundations				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Excavation and Backfill	24	Turbine	$ 27,500.00	$ 660,000.00
Foundation installation	24	Turbine	$ 462,000.00	$ 11,088,000.00
			Subtotal	$ 11,748,000.00
Turbine Installations				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Crane mobilization, movement, install, mechanical completion	24	Turbine	$ 517,500.00	$ 12,420,000.00
			Subtotal	$ 12,420,000.00
Substation				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Civil Works	1	LS	$ 1,000,000.00	$ 1,000,000.00
Foundation and Grounding Works	1	LS	$ 1,000,000.00	$ 1,000,000.00
Electrical Equipment	1	LS	$ 4,000,000.00	$ 4,000,000.00
VAR Compensation	1	Allowance	$ 500,000.00	$ 500,000.00
Installation and testing	1	LS	$ 3,000,000.00	$ 3,000,000.00
			Subtotal	$ 9,500,000.00
Transmission System				
	Quantity	**Unit**	**Unit Rate**	**Cost**
5km 138kV line	5	km	$ 400,000.00	$ 2,000,000.00
			Subtotal	$ 2,000,000.00
3-Breaker Ring Station at POI				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Major Equipment	1	LS	$ 2,000,000.00	$ 2,000,000.00
Civil/Structural Work	1	LS	$ 500,000.00	$ 500,000.00
Engineering Cost	1	LS	$ 500,000.00	$ 500,000.00
Construction/Commissioning Cost	1	LS	$ 2,000,000.00	$ 2,000,000.00
			Subtotal	$ 5,000,000.00
Collection System				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Material supply, trenching, placement of cables, backfilling, pole placement and dressing, conductor stringing for 34.5kV collection system	36400	m	$ 250.00	$ 9,100,000.00
Padmount Transformers Supply and Installation, Including cable termination	0	Turbine	$ 200,000.00	$ -
Crossing allowance (utility, water, etc.)	2	Crossings	$ 20,000.00	$ 40,000.00
			Subtotal	$ 9,140,000.00

SCADA/Communications					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Substation SCADA System	1	LS	$ 400,000.00	$ 400,000.00	
Fiber Optic Cable terminations	53	Sites	$ 5,000.00	$ 265,000.00	
MET Towers	2	Unit	$ 450,000.00	$ 900,000.00	
Site Comms Medium Established	1	Allowance	$ 500,000.00	$ 500,000.00	
			Subtotal	$ 2,065,000.00	
Misc. Site Costs					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Surveying	1	LS	$ 400,000.00	$ 400,000.00	
Testing Collectors, Substation, and T-Line	1	LS	$ 450,000.00	$ 450,000.00	
Testing for Roads and Foundations	1	LS	$ 350,000.00	$ 350,000.00	
Allowance for O&M building costs	1	LS	$ 800,000.00	$ 800,000.00	
			Subtotal	$ 2,000,000.00	
Contractor Engineering					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Civil Engineering including Foundation	1	LS	$ 250,000.00	$ 250,000.00	
Collection System Engineering	1	LS	$ 350,000.00	$ 350,000.00	
Substation Engineering	1	LS	$ 650,000.00	$ 650,000.00	
T-Line Engineering	1	LS	$ 650,000.00	$ 650,000.00	
Geotech Study	1	LS	$ 250,000.00	$ 250,000.00	
			Subtotal	$ 2,150,000.00	
Contractor Construction Management					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Staff and Management	17	Months	$ 220,000.00	$ 3,740,000.00	
Temporary Installation Including Power, Fuel and Comms	17	Months	$ 50,000.00	$ 850,000.00	
Health, Safety and Environmental	17	Months	$ 10,000.00	$ 170,000.00	
			Subtotal	$ 4,760,000.00	
			Total	$ 71,693,900.00	
			BOP Cost Per MW	$ 711,249.01	

Appendix B

12.6 MW Estimate

NEW COLLIERS LTD.

Preliminary Project Development and Construction Estimate
07-Aug-18

Site	**Newfoundland representative site**	
Number of WTG	**3**	
Turbine type	**Vestas V136**	
Size of turbine	**4.2**	MW
Size of project in MW	**12.6**	MW

Total Costs

	Year 1	Year 2	Year 3	Year 4	**Cost**
Owner/Development Activities	$364,250	$680,750	$585,000	$0	$1,630,000
Turbine Supply		$3,528,000	$14,112,000	$0	$17,640,000
BOP Construction and Commissioning			$9,726,620	$0	$9,726,620
Annual Subtotals	*$364,250*	*$4,208,750*	*$24,423,620*	*$0*	
				Project Cost	**$28,996,620**
				Project Cost per MW	**$2,301,319.05**

Development Activities

	Year 1	**Year 2**	**Year 3**	**Year 4**	**Cost**
Met tower deployment 1 tower	$110,000	$0			$110,000
WRA analysis for 1 year, WRA reports	$17,000	$68,000			$85,000
Site surveying, desktop geotechnical study	$2,250	$12,750			$15,000
Stakeholder consultation/engagement	$75,000	$75,000			$150,000
Land acquisition	$0	$25,000			$25,000
Interconnection studies, application and agreement	$15,000	$85,000			$100,000
Interconnection fee	$0		$150,000		$150,000
Environmental Impact Assessment	$45,000	$105,000			$150,000
Project contract procurement and PPA pricing	$70,000	$280,000			$350,000
Inhouse engineering, project management and oversig	$30,000	$30,000	$120,000		$180,000
Construction management	$0	$0	$165,000		$165,000
Land rental during construction	$0	$0	$25,000		$25,000
Permits and licenses	$0	$0	$125,000		$125,000
Annual Subtotals	*$364,250*	*$680,750*	*$585,000*	*$0*	
				Development Cost	**$1,630,000**
				Development Cost per MW	**$129,365**

Turbine Supply, Delivery and Commissioning

	Year 2	**Year 3**	**Cost**
24 Vestas V136 4.2MW turbines	$3,528,000	$14,112,000	$17,640,000
		Turbine Cost	**$17,640,000**
		Turbine Cost per MW	**$1,400,000**

Balance-of-Plant (BOP) Construction Estimate

			V136		
Construct WTG Sites and Crane Pads					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Wood Cutting and Grubbing	3	Turbine	$ 17,160.00	$ 51,480.00	
Excavation, backfill and crane pad prep	3	Turbine	$ 57,200.00	$ 171,600.00	
WTG Sites Reclamation	3	Turbine	$ 5,005.00	$ 15,015.00	
			Subtotal	$ 238,095.00	
Construct Laydown and Trailer Area					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Excavate and Backfill Trailer Area	1	each	$ 65,000.00	$ 65,000.00	
Excavate and Backfill Concrete Batch Plant Area	1	each	$ -	$ -	
Reclamation of Temporary Area	1	LS	$ 50,000.00	$ 50,000.00	
			Subtotal	$ 115,000.00	
Improve Existing Roads					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Improve Existing Roads	2000	m	$ 107.25	$ 214,500.00	
Allowance for improved major approaches	1	each	$ 71,500.00	$71,500.00	
			Subtotal	$ 286,000.00	
Construct New Roads and Drainage					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Wood Cutting and Grubbing	7	Ha	$ 15,600.00	$ 109,200.00	
Construct new roads	3500	m	$ 228.80	$ 800,800.00	
Roads maintenance and reclamation	3500	m	$ 64.35	$ 225,225.00	
			Subtotal	$ 1,135,225.00	
Foundations					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Excavation and Backfill	3	Turbine	$ 35,750.00	$ 107,250.00	
Foundation installation	3	Turbine	$ 600,600.00	$ 1,801,800.00	
			Subtotal	$ 1,909,050.00	
Turbine Installations					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Crane mobe, movement, install, mechanical completion	3	Turbine	$ 672,750.00	$ 2,018,250.00	
			Subtotal	$ 2,018,250.00	
Distribution Interconnection Area					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Civil Works	1	LS	$ 15,000.00	$ 15,000.00	
Foundation and Grounding Works	1	LS	$ 15,000.00	$ 15,000.00	
Electrical Equipment	1	LS	$ 250,000.00	$ 250,000.00	
VAR Compensation	1	Allowance	$ -	$ -	
Installation and testing	1	LS	$ 50,000.00	$ 50,000.00	
			Subtotal	$ 330,000.00	
Transmission System - N/A					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
5km 138kV line	0	km	$ 400,000.00	$ -	
			Subtotal	$ -	
3-Breaker Ring Station at POI - N/A					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Major Equipment	0	LS	$ 1,400,000.00	$ -	
Engineering Cost	0	LS	$ 350,000.00	$ -	
Construction/Commissioning Cost	0	LS	$ 2,100,000.00	$ -	
			Subtotal	$ -	

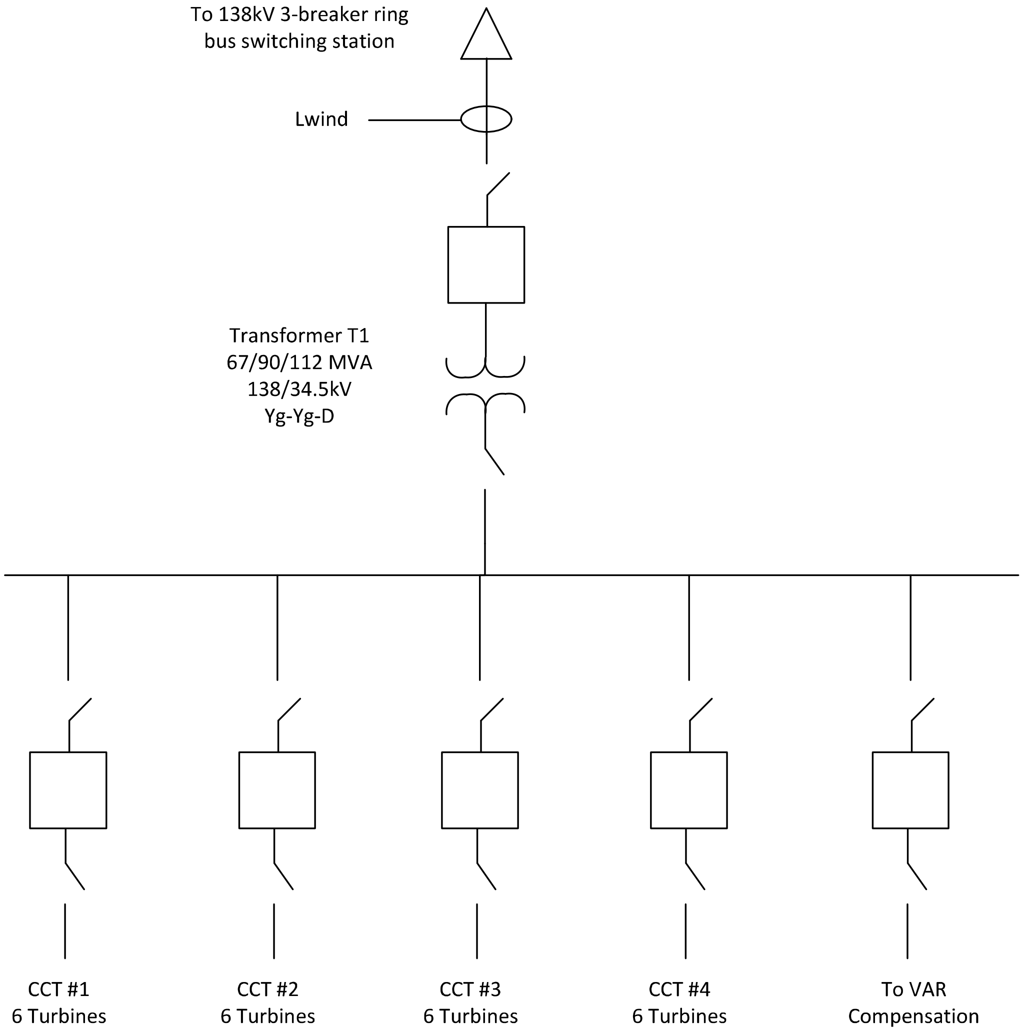
Collection System					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Material supply, trenching, placement of cables, backfilling, pole placement and dressing, conductor stringing for 25kV collection system	5300	m	$ 250.00	$ 1,325,000.00	
Padmount Transformers Supply and Installation, Including cable termination	0	Turbine	$ 200,000.00	$ -	
Crossing allowance	1	Crossings	$ 25,000.00	$ 25,000.00	
			Subtotal	$ 1,350,000.00	
SCADA/Communications					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Project SCADA System	1	LS	$ 250,000.00	$ 250,000.00	
Fiber Optic Cable terminations	8	Sites	$ 7,500.00	$ 60,000.00	
MET Towers	0	Unit	$ 450,000.00	$ -	
Site Comms Medium Established	1	Allowance	$ 125,000.00	$ 125,000.00	
			Subtotal	$ 435,000.00	
Misc. Site Costs					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Surveying	1	LS	$ 150,000.00	$ 150,000.00	
Testing Collectors, Distribution Station	1	LS	$ 112,500.00	$ 112,500.00	
Testing for Roads and Foundations	1	LS	$ 50,000.00	$ 50,000.00	
Allowance for O&M building costs	1	LS	$ 150,000.00	$ 150,000.00	
			Subtotal	$ 462,500.00	
Contractor Engineering					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Civil Engineering including Foundation	1	LS	$ 75,000.00	$ 75,000.00	
Collection System Engineering	1	LS	$ 50,000.00	$ 50,000.00	
Distribution Station Engineering	1	LS	$ 100,000.00	$ 100,000.00	
T-Line Engineering N/A	0	LS	$ 650,000.00	$ -	
Geotech Study	1	LS	$ 30,000.00	$ 30,000.00	
			Subtotal	$ 255,000.00	
Contractor Construction Management					
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Staff and Management	9	Months	$ 100,000.00	$ 900,000.00	
Temporary Installation Including Power and Comms	9	Months	$ 25,000.00	$ 225,000.00	
Health, Safety and Environmental	9	Months	$ 7,500.00	$ 67,500.00	
			Subtotal	$ 1,192,500.00	
			Total	$ 9,726,620.00	
			BOP Cost Per MW	$ 771,953.97	

Appendix C

Transmission SLDs

NEW COLLIERS LTD.

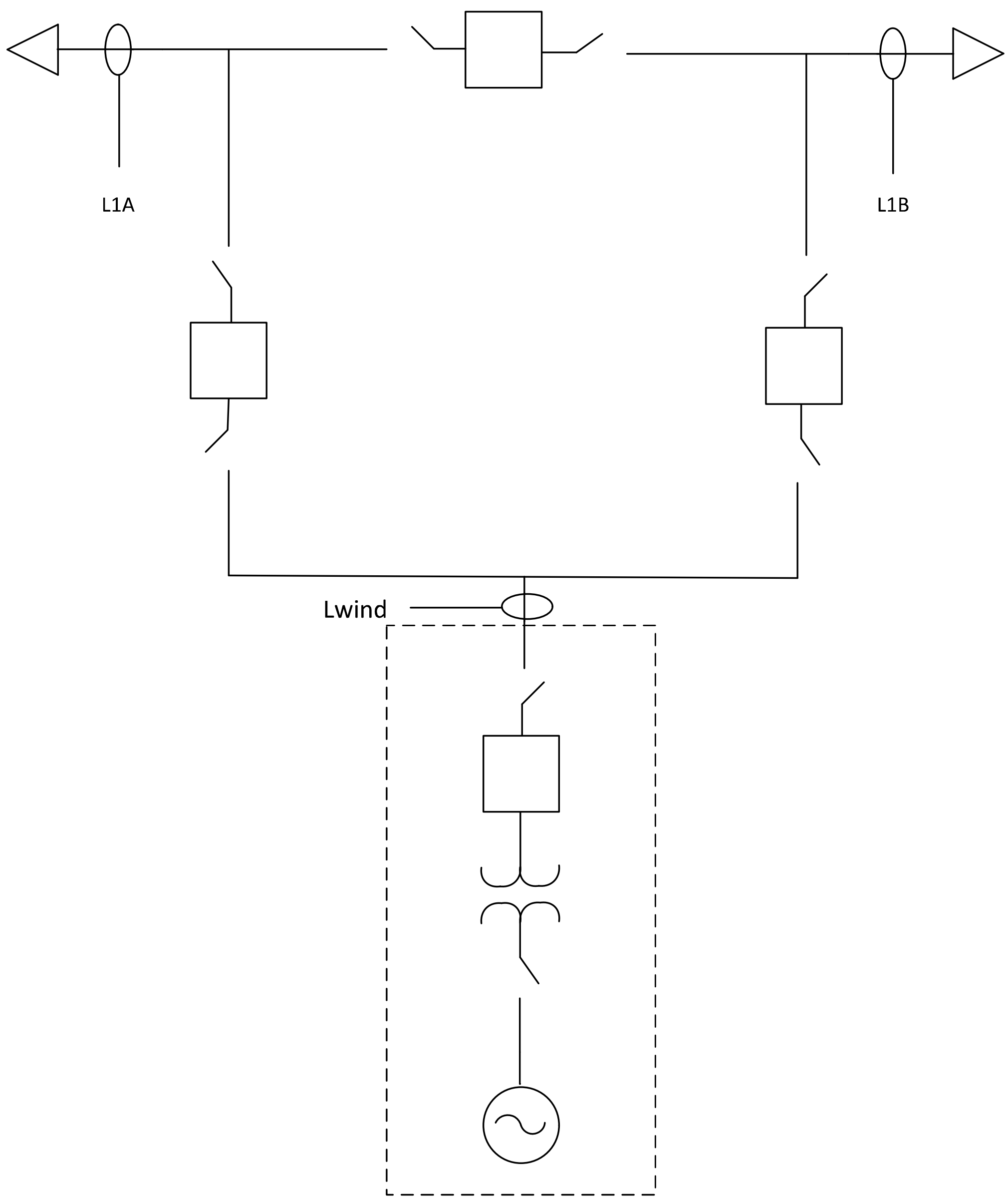
100.8MW Wind Project
138/34.5kV Project Substation
Preliminary Single Line Diagram
Rev. A – August 7, 2018



NEW COLLIERS LTD.

100.8MW Wind Project
138kV Interconnecting Ring Bus Station
Preliminary Single Line Diagram
Rev. A – August 7, 2018

NOTE: Existing line L1 to be tapped by Lwind using 3-breaker ring arrangement



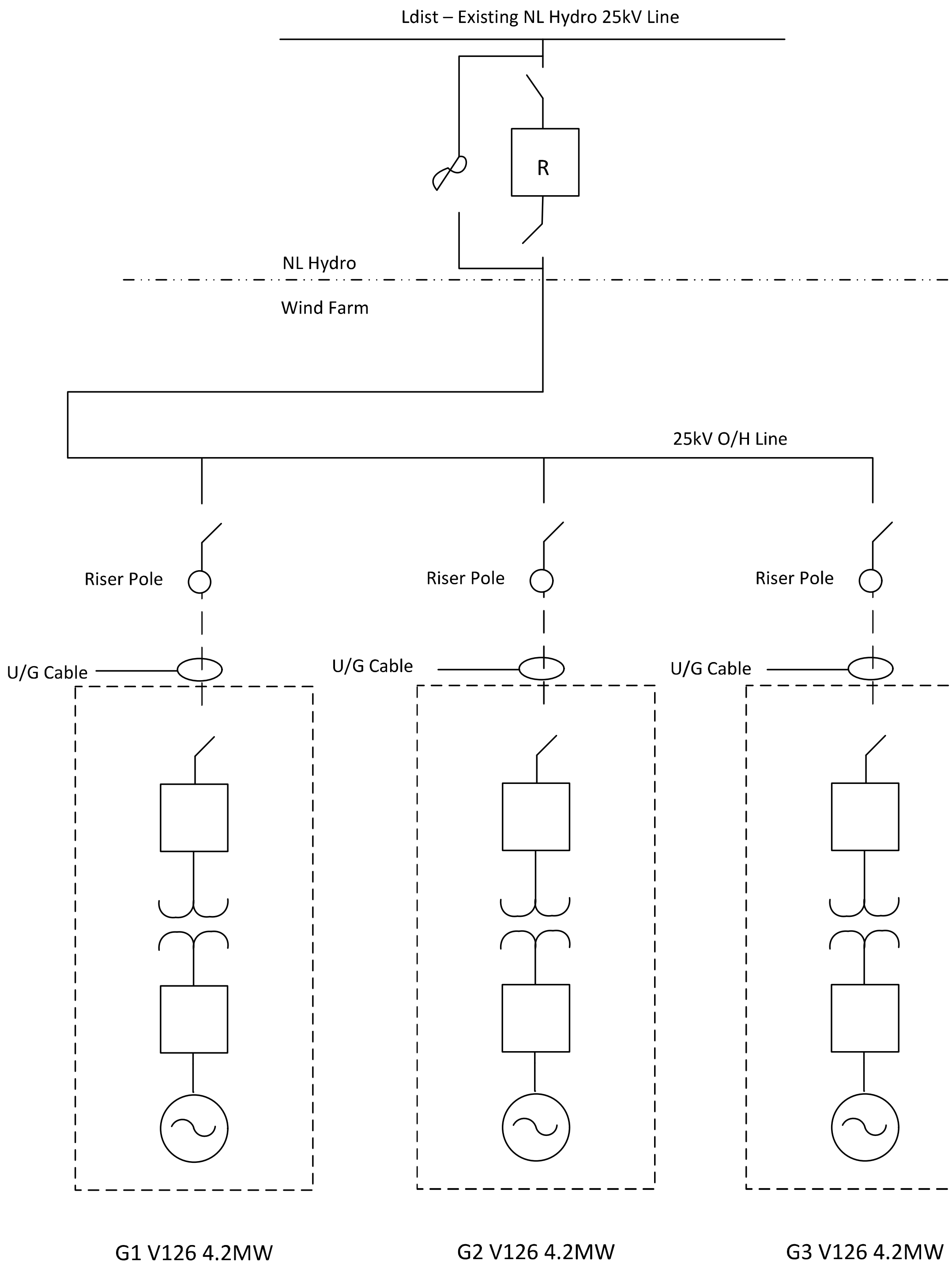
New 100.8 MW
Project

Appendix D

Distribution SLD

NEW COLLIERS LTD.

100.8MW Wind Project
25kV Distribution Interconnection Station
Preliminary Single Line Diagram
Rev. A – August 7, 2018



Appendix E

Vestas 4.2MW V136 WTG Brochure

Vestas®

4MW PLATFORM

Wind. It means the world to us.™

Are you looking for the maximum return on **your investment** in wind energy?

Wind energy means the world to us. And we want it to mean the world to our customers, too, by maximising your profits and strengthening the certainty of your investment in wind power.

That's why, together with our partners, we always strive to deliver cost-effective wind technologies, high quality products and first class services throughout the entire value chain. And it's why we put so much emphasis on the reliability, consistency and predictability of our technology.

We have more than 35 years' experience in wind energy. During that time, we've delivered 92 GW of installed capacity in 79 countries. That is more than anyone else in the industry. We currently monitor over 33,000 wind turbines across the globe. All tangible proof that Vestas is the right partner to help you realise the full potential of your wind site.

What is the 4 MW Platform today?

The Vestas 4 MW platform* was introduced in 2010 with the launch of the V112-3.0 MW®. Over 18 GW of the 4 MW platform has been installed all over the world onshore and offshore making it the obvious choice for customers looking for highly flexible and trustworthy turbines.

Since then the 4 MW platform was upgraded and new variants were introduced utilising untapped potential of the platform. All variants carry the same nacelle design and the hub design has been re-used to the largest extend possible. In addition, our engineers have increased the nominal power across the entire platform improving your energy production significantly.

With this expansion, the 4 MW platform covers all IEC wind classes with a variety of rotor sizes and a higher rated output power of up to 4.2 MW.

You can choose from the following turbines on the 4 MW platform:

- V105-3.45 MW™ – IEC IA
- V112-3.45 MW® – IEC IA
- V117-3.45 MW® – IEC IB/IEC IIA
- V117-4.2 MW™ – IEC IB/IEC IIA/IEC S
- V126-3.45 MW® – IEC IIB/IEC IIA
- V136-3.45 MW® – IEC IIB/IEC IIIA
- V136-4.2 MW™ – IEC IIB/IEC S
- V150-4.2 MW™ – IEC IIIB/IEC S

All variants of the 4 MW platform are based on the proven technology of the V112-3.0 MW® with a full-scale converter, providing you with superior grid performance.

Our 4 MW platform is designed for a broad range of wind and site conditions, enabling you to mix turbines across your site or portfolio of sites, delivering industry-leading reliability, serviceability and exceptional energy capture, optimising your business case.

All turbine variants are equipped with the same ergonomically designed and very spacious nacelle which makes it easier for maintenance crews to gain access, so they can reduce the time spent on service while maximizing the uptime without compromising safety. All turbines can be installed and maintained using standard installation and servicing tools and equipment further reducing the operation and maintenance costs by minimising your stock level of spare parts.

*Formerly named the Vestas 3 MW platform


+64,000
The V112-3.45 MW® and the other 4 MW variants advance the already proven technology powering over 64,000 installed Vestas turbines worldwide - more than any other supplier.

How does our technology generate **more energy?**

More power for every wind site

V112-3.45 MW®, V117-3.45 MW®, V117-4.2 MW™, V126-3.45 MW®, V136-3.45 MW®, V136-4.2 MW™ and V150-4.2 MW™ are available with several Sound Optimised Modes to meet sound level restrictions with an optimised production. The power system enables superior grid support and it is capable of maintaining production across severe drops in grid voltage, while simultaneously minimising tower and foundation loads. It also allows rapid down-rating of production to 10 per cent nominal power.

Proven technologies - from the company that invented them

The 4 MW platform is a low-risk choice. It is based on the proven technologies that underpin more than 64,000 Vestas turbines installed around the world. Using the best features from across the range, as well as some of the industry's most stringently tested components and systems, the platform's reliable design minimises downtime – helping to give you the best possible return on your investment.

With an operating range that covers all wind classes, our 4 MW platform delivers unrivalled energy production. The proven blade technology from the V112-3.0 MW® is used on the V105-3.45 MW™, the V112-3.45 MW®, V117-3.45 MW® and V117-4.2 MW™. The industry known structural shell blades are used on the V126-3.45 MW®, V136-3.45 MW®, V136-4.2 MW™ and V150-4.2 MW™- a technology which is also used on the 2 MW V110-2.0 MW®, V116-2.0 MW™ and V120-2.0 MW™ variants.

Reliable and robust

The Vestas Test Centre is unrivalled in the wind industry. We test most nacelle components using Highly Accelerated Life Testing (HALT) to ensure reliability. For critical components, HALT identifies potential failure modes and mechanisms. Specialised test rigs ensure strength and robustness for the gearbox, generator, yaw and pitch system, lubrication system and accumulators. Our quality-control system ensures that each component is manufactured to design specifications and performs at site. We systematically monitor measurement trends that are critical to quality, locating defects before they occur.

The 4 MW platform covers all wind segments enabling you to find the best turbine for your specific site.

WINDCLASSES - IEC

TURBINE TYPE	IEC III (6.0 - 7.5 m/s)	IEC II (7.5 - 8.5 m/s)	IEC I (8.5 - 10.0 m/s)
4 MW TURBINES			
V105-3.45 MW™ IEC IA			Standard IEC conditions
V112-3.45 MW® IEC IA			Standard IEC conditions
V117-3.45 MW® IEC IB/IEC IIA		Standard IEC conditions	Standard IEC conditions
V117-4.2 MW™ IEC IB/IEC IIA/IEC S		Standard IEC conditions	Standard IEC conditions
V126-3.45 MW® IEC IIA/ IEC IIB	Standard IEC conditions	Standard IEC conditions	Site dependent
V136-3.45 MW® IEC IIB/ IEC IIIA	Standard IEC conditions	Standard IEC conditions	Site dependent
V136-4.2 MW™ IEC IIB/IEC S	Standard IEC conditions	Standard IEC conditions	Site dependent
V150-4.2 MW™ IEC IIIB/IEC S	Standard IEC conditions	Site dependent	

■ Standard IEC conditions ■ Site dependent

Options available for the 4 MW platform
An option is an extra feature that can be added to the turbine to suit a project's specific needs. By adding options to the standard turbine, we can enhance the performance and adaptability of the wind power project and facilitate a shorter permitting cycle at restricted sites. The options can even be a decisive factor in realising your specific project, and the business case certainty of the investment.

Here is a list of the options available for the 4 MW platform:
- Power Optimised Modes
- Load Optimised Modes
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Vestas De-Icing
- Low Temperature Operation to - 30°C
- Fire Suppression
- Shadow detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight™

Life testing

The Vestas Test Centre has the unique ability to test complete nacelles using technologies like Highly Accelerated Life Testing (HALT). This rigorous testing of new components ensures the reliability of the 4 MW platform.

Is the 4 MW platform the optimal choice for **your specific site?**

One common nacelle – six different rotor sizes
The wind conditions on a wind project site are often not identical. The 4 MW platform features a range of turbines that cover all wind classes and combined across your site they can maximise the energy output of your wind power plant.

Tip-height restrictions and strict grid requirements
With a rotor size of 105 m, the V105-3.45 MW™ IEC IA is the turbine that fits the most severe wind conditions. It has an extremely robust design for tough site conditions and is especially suited for markets with tip-height restrictions and high grid requirements.

Like all the other 4 MW turbines, the V105-3.45 MW™ is equipped with a full-scale converter ensuring full compliance with the challenging grid codes in countries like the UK and Ireland.

Cold climates
The V112-3.45 MW®, V117-3.45 MW® , V117-4.2 MW™, V126-3.45MW®, V136-3.45 MW® can be combined with Vestas De-Icing and Vestas Ice Detection ensuring optimum production in cold climates.

The Vestas De-Icing System is fully SCADA integrated and can be triggered automatically or manually depending on your de-icing strategy. Automatic control protects your investment, optimising the trigger point so the turbine only stops to de-ice when there is an expected net power production gain.

High- and medium-wind sites
The V112-3.45 MW® IEC IA is a high-wind turbine and has a very high capacity factor. Similar to the other 4 MW turbines, the V112-3.45 MW® IEC IA turbine makes efficient use of its grid compatibility and is an optimal choice for sites with MW constraints.

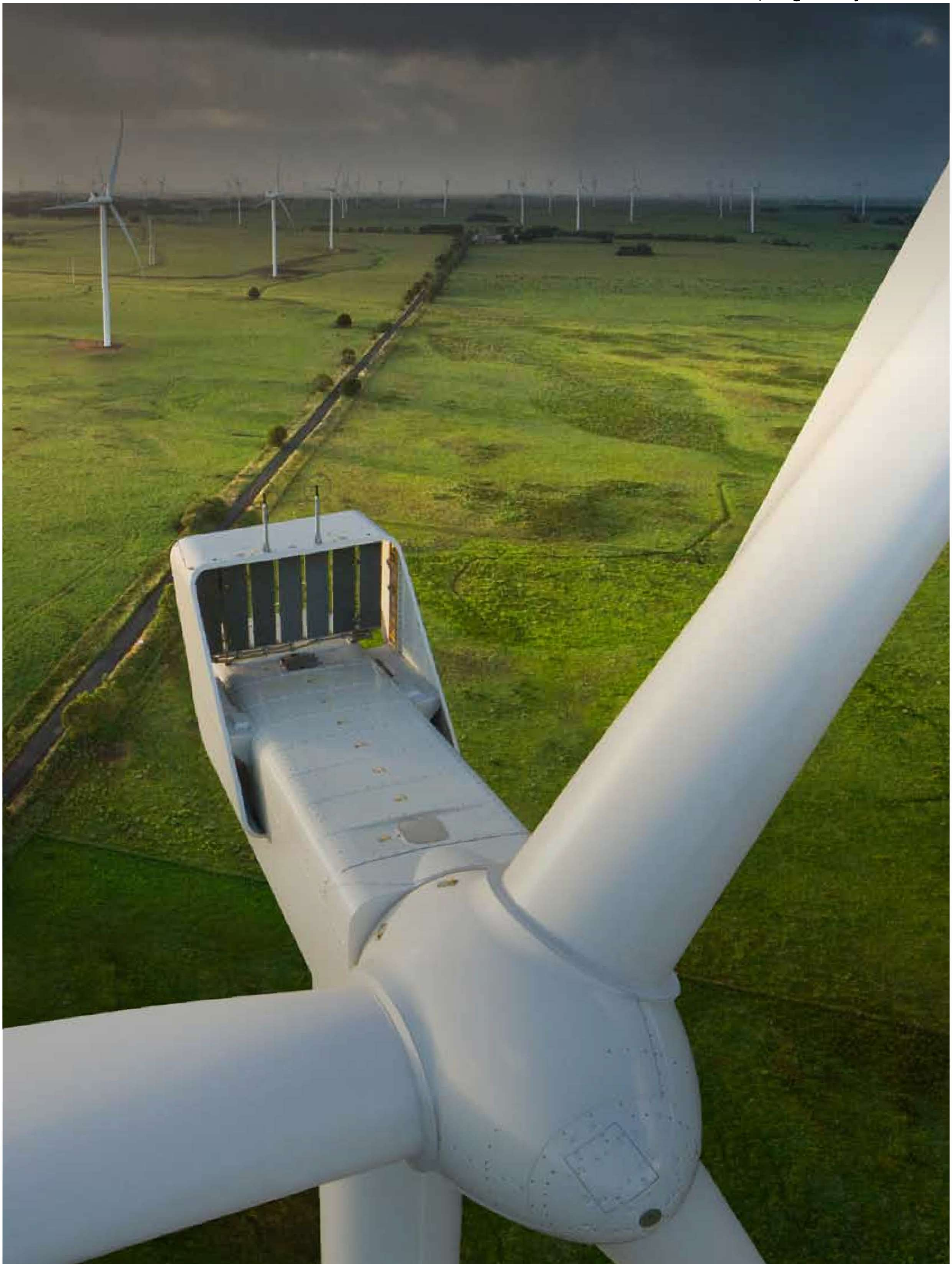
On medium wind-sites, the V117-3.45 MW® IEC IB/IEC IIA, V126-3.45 MW® IEC IIA/IEC IIB, V136-3.45 MW® IEC IIB/IEC IIIA and V136-4.2 MW IEC IIB/IEC S are excellent turbine choices. A combination of the variants can optimise your site layout and improve your production significantly on complex sites.

Low-wind sites
Built on the same proven technology as the V112-3.0 MW®, the V150-4.2 MW™ IEC IIIB/IEC S is our best performer on low-wind sites. The larger rotor enable greater wind capture, which in turn produces more energy to reduce levelised cost of energy (LCOE). The result is exceptional profitability in areas with low wind, and new frontiers for wind energy investment.

Large Diameter Steel Towers (LDST) support the added rotor size and rating of Vestas turbines to increase Annual Energy Production on low-wind sites. LDST is specially designed with a larger diameter in the bottom section that allows for optimal strength at high hub heights.

Maximising old permits
Although the V150-4.2 MW™ is one of the highest producing low wind turbines available, some old permits may simply be too tight to accept it. Although the V117-3.45 MW®, V126-3.45 MW®, V136-3.45 MW® and V136-4.2 MW™ are medium-wind turbines, they still deliver an excellent business case on low-wind sites.

Due to the similar electrical properties and nacelle design, it is easy to mix and match the turbines from the 4 MW platform to maximise production on heavily constrained sites.



Would you **benefit** from uninterrupted control of wind energy production?

Knowledge about wind project planning is key
Getting your wind energy project up and operating as quickly as possible is fundamental to its long-term success. One of the first and most important steps is to identify the most suitable location for your wind power plant. Vestas' SiteHunt® is an advanced analytical tool that examines a broad spectrum of wind and weather data to evaluate potential sites and establish which of them can provide optimum conditions for your project.

In addition, SiteDesign® optimises the layout of your wind power plant. SiteDesign® runs Computational Fluid Dynamics (CFD) software on our powerful in-house supercomputer Firestorm to perform simulations of the conditions on site and analyse their effects over the whole operating life of the plant. Put simply, it finds the optimal balance between the estimated ratio of annual revenue to operating costs over the lifetime of your plant, to determine your project's true potential and provide a firm basis for your investment decision.

The complexity and specific requirements of grid connections vary considerably across the globe, making the optimal design of electrical components for your wind power plant essential. By identifying grid codes early in the project phase and simulating extreme operating conditions, Electrical PreDesign provides you with an ideal way to build a grid compliant, productive and highly profitable wind power plant. It allows customised collector network cabling, substation protection and reactive power compensation, which boost the cost efficiency of your business.

Advanced monitoring and real-time plant control
All our wind turbines can benefit from VestasOnline® Business, the latest Supervisory Control and Data Acquisition (SCADA) system for modern wind power plants.

This flexible system includes an extensive range of monitoring and management functions to control your wind power plant. VestasOnline® Business enables you to optimise production levels,

+33,000

The Vestas Performance and Diagnostics Centre monitors more than 33,000 turbines worldwide. We use this information to continually develop and improve our products and services.

monitor performance and produce detailed, tailored reports from anywhere in the world. The VestasOnline® Power Plant Controller offers scalability and fast, reliable real-time control and features customisable configuration, allowing you to implement any control concept needed to meet local grid requirements.

Surveillance, maintenance and service

Operating a large wind power plant calls for efficient management strategies to ensure uninterrupted power production and to control operational expenses. We offer 24/7 monitoring, performance reporting and predictive maintenance systems to improve turbine performance and availability. Predicting faults in advance is essential, helping to avoid costly emergency repairs and unscheduled interruptions to energy production.

Our Condition Monitoring System (CMS) assesses the status of the turbines by analysing vibration signals. For example, by measuring the vibration of the drive train, it can detect faults at an early stage and monitor any damage. This information allows pre-emptive maintenance to be carried out before the component fails, reducing repair costs and production loss.

Additionally, our Active Output Management® (AOM) concept provides detailed plans and long term agreements for service and maintenance, online monitoring, optimisation and troubleshooting. It is possible to get a full scope contract, combining your turbines' state-of-the-art technology with guaranteed time or energy-based availability performance targets, thereby creating a solid base for your power plant investment. The Active Output Management® agreement provides you with long term and financial operational peace of mind for your business case.

V105-3.45 MW™ IEC IA
Facts & figures

POWER REGULATION Pitch regulated with variable speed

OPERATING DATA

Rated power	3,450 kW
Cut-in wind speed	3 m/s
Cut-out wind speed	25 m/s
Re cut-in wind speed	23 m/s
Wind class	IEC IA

Standard operating temperature range from -20°C* to +45°C with de-rating above 30°C

*Subject to different temperature options

SOUND POWER

Maximum	104.5 dB(A)**

**Sound Optimised Modes dependent on site and country

ROTOR

Rotor diameter	105 m
Swept area	8,659 m²
Air brake	full blade feathering with 3 pitch cylinders

ELECTRICAL

Frequency	50/60 Hz
Converter	full scale

GEARBOX

Type	two planetary stages and one helical stage

TOWER

Hub height	72.5 m (IEC IA)

NACELLE DIMENSIONS

Height for transport	3.4 m
Height installed (incl. CoolerTop®)	6.9 m
Length	12.8 m
Width	4.2 m

HUB DIMENSIONS

Max. transport height	3.8 m
Max. transport width	3.8 m
Max. transport length	5.5 m

BLADE DIMENSIONS

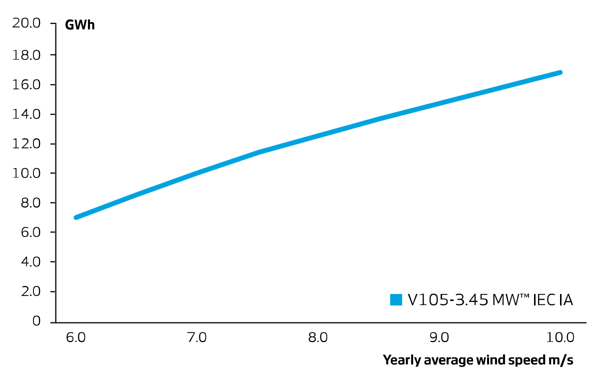
Length	51.2 m
Max. chord	4 m

Max. weight per unit for transportation	70 metric tonnes

TURBINE OPTIONS

- High Wind Operation
- Power Optimised Mode up to 3.6 MW (site specific)
- Load Optimised Modes down to 3.0 MW
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Low Temperature Operation to -30°C
- Fire Suppression
- Shadow Detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight™

ANNUAL ENERGY PRODUCTION



Assumptions
One wind turbine, 100% availability, 0% losses, k factor = 2,
Standard air density = 1.225, wind speed at hub height

V112-3.45 MW® IEC IA
Facts & figures

POWER REGULATION	Pitch regulated with variable speed

OPERATING DATA

Rated power	3,450 kW
Cut-in wind speed	3 m/s
Cut-out wind speed	25 m/s
Re cut-in wind speed	23 m/s
Wind class	IEC IA

Standard operating temperature range from -20°C* to +45°C with de-rating above 30°C

*subject to different temperature options

SOUND POWER

Maximum	105.4 dB(A)**

**Sound Optimised Modes dependent on site and country

ROTOR

Rotor diameter	112 m
Swept area	9,852 m²
Air brake	full blade feathering with 3 pitch cylinders

ELECTRICAL

Frequency	50/60 Hz
Converter	full scale

GEARBOX

Type	two planetary stages and one helical stage

TOWER

Hub height	69 m (IEC IA) and 94 m (IEC IA)

NACELLE DIMENSIONS

Height for transport	3.4 m
Height installed (incl. CoolerTop®)	6.9 m
Length	12.8 m
Width	4.2 m

HUB DIMENSIONS

Max. transport height	3.8 m
Max. transport width	3.8 m
Max. transport length	5.5 m

BLADE DIMENSIONS

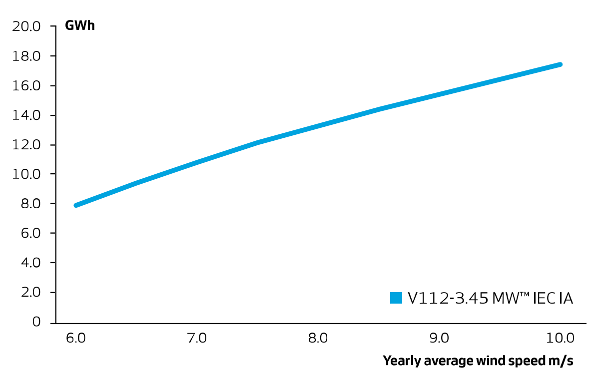
Length	54.7 m
Max. chord	4 m

Max. weight per unit for transportation	70 metric tonnes

TURBINE OPTIONS

- High Wind Operation
- Power Optimised Mode up to 3.6 MW (site specific)
- Load Optimised Modes down to 3.0 MW
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Vestas De-Icing
- Low Temperature Operation to - 30°C
- Fire Suppression
- Shadow detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight™

ANNUAL ENERGY PRODUCTION



Assumptions
One wind turbine, 100% availability, 0% losses, k factor = 2,
Standard air density = 1.225, wind speed at hub height

V117-3.45 MW® IEC IB/IEC IIA
Facts & figures

POWER REGULATION — Pitch regulated with variable speed

OPERATING DATA

Rated power	3,450 kW
Cut-in wind speed	3 m/s
Cut-out wind speed	25 m/s
Re cut-in wind speed	23 m/s
Wind class	IEC IB/IEC IIA

Standard operating temperature range from -20°C* to +45°C with de-rating above 30°C

*subject to different temperature options

SOUND POWER

Maximum	106.8 dB(A)**

**Sound Optimised Modes dependent on site and country

ROTOR

Rotor diameter	117 m
Swept area	10,751 m²
Air brake	full blade feathering with 3 pitch cylinders

ELECTRICAL

Frequency	50/60 Hz
Converter	full scale

GEARBOX

Type	two planetary stages and one helical stage

TOWER

Hub heights	80 m (IEC IB), 91.5 m (IEC IB) and 116.5 m (IEC IB/IEC IIA/DIBtS)

NACELLE DIMENSIONS

Height for transport	3.4 m
Height installed (incl. CoolerTop®)	6.9 m
Length	12.8 m
Width	4.2 m

HUB DIMENSIONS

Max. transport height	3.8 m
Max. transport width	3.8 m
Max. transport length	5.5 m

BLADE DIMENSIONS

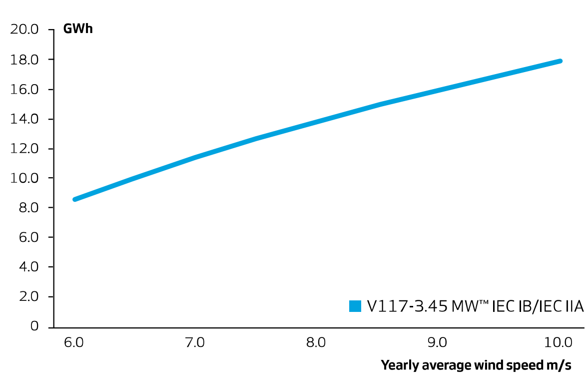
Length	57.2 m
Max. chord	4 m

Max. weight per unit for transportation	70 metric tonnes

TURBINE OPTIONS

- High Wind Operation
- Power Optimised Mode up to 3.6 MW (site specific)
- Load Optimised Modes down to 3.0 MW
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Vestas De-Icing
- Low Temperature Operation to - 30°C
- Fire Suppression
- Shadow detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight™

ANNUAL ENERGY PRODUCTION



Assumptions
One wind turbine, 100% availability, 0% losses, k factor = 2,
Standard air density = 1.225, wind speed at hub height

V117-4.2 MW™ IEC IB/IEC IIA/IEC S
Facts & figures

POWER REGULATION Pitch regulated with variable speed

OPERATING DATA

Rated power	4,000 kW/4,200 kW
Cut-in wind speed	3 m/s
Cut-out wind speed	25 m/s
Re cut-in wind speed	23 m/s
Wind class	IEC IB/IEC IIA/IEC S

Standard operating temperature range from -20°C* to +45°C with de-rating above 30°C (4,000 kW)

*subject to different temperature options

SOUND POWER

Maximum	106 dB(A)**

**Sound Optimised Modes dependent on site and country

ROTOR

Rotor diameter	117 m
Swept area	10,751 m²
Air brake	full blade feathering with 3 pitch cylinders

ELECTRICAL

Frequency	50/60 Hz
Converter	full scale

GEARBOX

Type	two planetary stages and one helical stage

TOWER

Hub heights	91.5 m (IEC IB) 84 m (IEC IIA)

NACELLE DIMENSIONS

Height for transport	3.4 m
Height installed (incl. CoolerTop®)	6.9 m
Length	12.8 m
Width	4.2 m

HUB DIMENSIONS

Max. transport height	3.8 m
Max. transport width	3.8 m
Max. transport length	5.5 m

BLADE DIMENSIONS

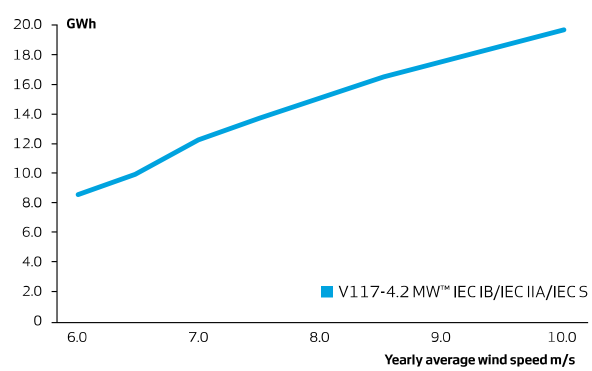
Length	57.2 m
Max. chord	4 m

Max. weight per unit for transportation	70 metric tonnes

TURBINE OPTIONS

- High Wind Operation
- 4.2 MW Power Optimised Mode (site specific)
- Load Optimised Modes down to 3.6 MW
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Vestas De-icing
- Low Temperature Operation to - 30°C
- Fire Suppression
- Shadow detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight®

ANNUAL ENERGY PRODUCTION



Assumptions
One wind turbine, 100% availability, 0% losses, k factor = 2,
Standard air density = 1.225, wind speed at hub height

V126-3.45 MW®
IEC IIB/IEC IIA
Facts & figures

POWER REGULATION	Pitch regulated with variable speed

OPERATING DATA

Rated power	3,450 kW
Cut-in wind speed	3 m/s
Cut-out wind speed	22.5 m/s
Re cut-in wind speed	20 m/s
Wind class	IEC IIB/IEC IIA

Standard operating temperature range from -20°C* to +45°C with de-rating above 30°C

*subject to different temperature options

SOUND POWER

Maximum	104.4 dB(A)** / 107.3 dB(A)**

**Sound Optimised Modes dependent on site and country

ROTOR

Rotor diameter	126 m
Swept area	12,469 m²
Air brake	full blade feathering with 3 pitch cylinders

ELECTRICAL

Frequency	50/60 Hz
Converter	full scale

GEARBOX

Type	two planetary stages and one helical stage

TOWER

Hub heights 87 m (IEC IIB/IEC IIA), 117 m (IEC IIB/IECIIA/DIBtS), 137 m (IEC IIIA/DIBtS), 147 m (IEC IIIA), 149 m (DIBtS) and 166 m (DIBtS)

NACELLE DIMENSIONS

Height for transport	3.4 m
Height installed (incl. CoolerTop®)	6.9 m
Length	12.8 m
Width	4.2 m

HUB DIMENSIONS

Max. transport height	3.8 m
Max. transport width	3.8 m
Max. transport length	5.5 m

BLADE DIMENSIONS

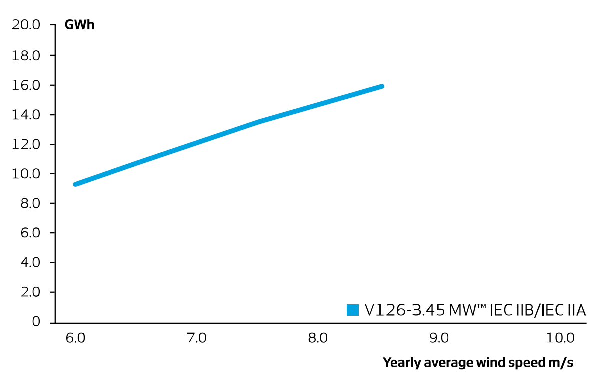
Length	61.7 m
Max. chord	4 m

Max. weight per unit for transportation	70 metric tonnes

TURBINE OPTIONS

- High Wind Operation
- Power Optimised Mode up to 3.6 MW (site specific)
- Load Optimised Modes down to 3.0 MW
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Vestas De-Icing
- Low Temperature Operation to - 30°C
- Fire Suppression
- Shadow detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight™

ANNUAL ENERGY PRODUCTION



Assumptions
One wind turbine, 100% availability, 0% losses, k factor = 2,
Standard air density = 1.225, wind speed at hub height

V136-3.45 MW® IEC IIB/IEC IIIA Facts & figures

POWER REGULATION Pitch regulated with variable speed

OPERATING DATA

Rated power	3,450 kW
Cut-in wind speed	3 m/s
Cut-out wind speed	22.5 m/s
Re cut-in wind speed	20 m/s
Wind class	IEC IIB/IEC IIIA

Standard operating temperature range from -20°C* to +45°C with de-rating above 30°C

*subject to different temperature options

SOUND POWER

Maximum	105.5 dB(A)**

**Sound Optimised Modes dependent on site and country

ROTOR

Rotor diameter	136 m
Swept area	14,527 m²
Air brake	full blade feathering with 3 pitch cylinders

ELECTRICAL

Frequency	50/60 Hz
Converter	full scale

GEARBOX

Type	two planetary stages and one helical stage

TOWER

Hub heights 82 m (IEC IIB/IEC IIIA), 105 m (IEC IIIA), 112 m (IEC IIB/IEC IIIA), 132 m (IEC IIB/IEC IIIA/ DIBt2), 142 m (IEC IIIA), 149 m (DIBtS), and 166 m (DIBtS)

NACELLE DIMENSIONS

Height for transport	3.4 m
Height installed (incl. CoolerTop®)	6.9 m
Length	12.8 m
Width	4.2 m

HUB DIMENSIONS

Max. transport height	3.8 m
Max. transport width	3.8 m
Max. transport length	5.5 m

BLADE DIMENSIONS

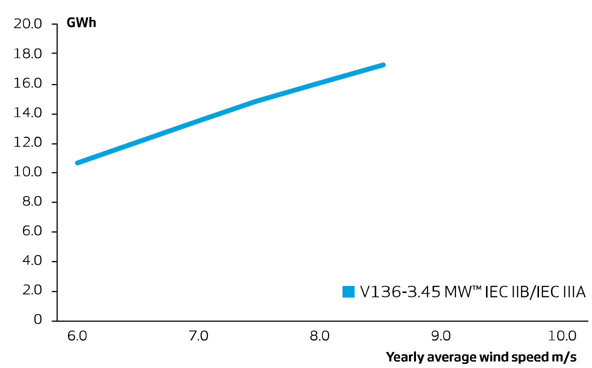
Length	66.7 m
Max. chord	4.1 m

Max. weight per unit for transportation	70 metric tonnes

TURBINE OPTIONS

- High Wind Operation
- Power Optimised Mode up to 3.6 MW (site specific)
- Load Optimised Modes down to 3.0 MW
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Vestas De-Icing
- Low Temperature Operation to - 30°C
- Fire Suppression
- Shadow detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight™

ANNUAL ENERGY PRODUCTION



Assumptions
One wind turbine, 100% availability, 0% losses, k factor = 2,
Standard air density = 1.225, wind speed at hub height

V136-4.2 MW™ IEC IIB/IEC S
Facts & figures

POWER REGULATION — Pitch regulated with variable speed

OPERATING DATA

Rated power	4,000 kW/4,200 kW
Cut-in wind speed	3 m/s
Cut-out wind speed	25 m/s
Re cut-in wind speed	23 m/s
Wind class	IEC IIB/IEC S

Standard operating temperature range from -20°C* to +45°C with de-rating above 30°C (4,000 kW)

*subject to different temperature options

SOUND POWER

Maximum	103.9 dB(A)**

**Sound Optimised modes dependent on site and country

ROTOR

Rotor diameter	136 m
Swept area	14,527 m²
Air brake	full blade feathering with 3 pitch cylinders

ELECTRICAL

Frequency	50/60 Hz
Converter	full scale

GEARBOX

Type	two planetary stages and one helical stage

TOWER

Hub heights	Site and country specific

NACELLE DIMENSIONS

Height for transport	3.4 m
Height installed (incl. CoolerTop®)	6.9 m
Length	12.8 m
Width	4.2 m

HUB DIMENSIONS

Max. transport height	3.8 m
Max. transport width	3.8 m
Max. transport length	5.5 m

BLADE DIMENSIONS

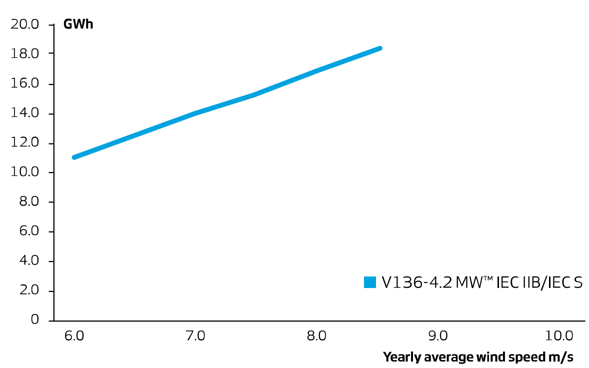
Length	66.7 m
Max. chord	4.1 m

Max. weight per unit for transportation	70 metric tonnes

TURBINE OPTIONS

- High Wind Operation
- 4.2 MW Power Optimised Mode (site specific)
- Load Optimised Modes down to 3.6 MW
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Low Temperature Operation to - 30°C
- Fire Suppression
- Shadow detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight®

ANNUAL ENERGY PRODUCTION



Assumptions
One wind turbine, 100% availability, 0% losses, k factor =2,
Standard air density = 1.225, wind speed at hub height

V150-4.2 MW™ IEC IIIB/IEC S
Facts & figures

POWER REGULATION Pitch regulated with variable speed

OPERATING DATA

Rated power	4,000 kW/4,200 kW
Cut-in wind speed	3 m/s
Cut-out wind speed	22.5 m/s
Re cut-in wind speed	20 m/s
Wind class	IEC IIIB/IEC S

Standard operating temperature range from -20°C* to +45°C with de-rating above 30°C (4,000 kW)

*subject to different temperature options

SOUND POWER

Maximum	104.9 dB(A)**

**Sound Optimised modes dependent on site and country

ROTOR

Rotor diameter	150 m
Swept area	17,671 m²
Air brake	full blade feathering with 3 pitch cylinders

ELECTRICAL

Frequency	50/60 Hz
Converter	full scale

GEARBOX

Type	two planetary stages and one helical stage

TOWER

Hub heights	Site and country specific

NACELLE DIMENSIONS

Height for transport	3.4 m
Height installed (incl. CoolerTop®)	6.9 m
Length	12.8 m
Width	4.2 m

HUB DIMENSIONS

Max. transport height	3.8 m
Max. transport width	3.8 m
Max. transport length	5.5 m

BLADE DIMENSIONS

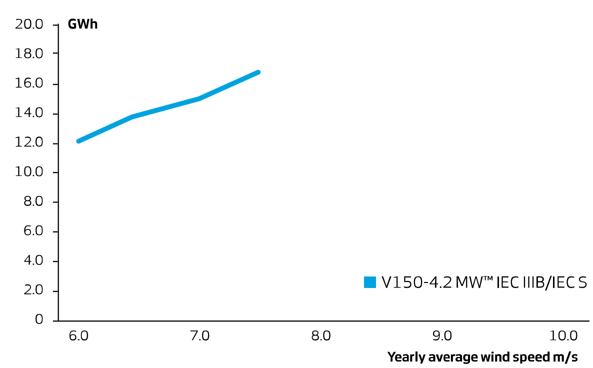
Length	73.7 m
Max. chord	4.2 m

Max. weight per unit for transportation	70 metric tonnes

TURBINE OPTIONS

- 4.2 MW Power Optimised Mode (site specific)
- Load Optimised Modes down to 3.6 MW
- Condition Monitoring System
- Service Personnel Lift
- Vestas Ice Detection
- Low Temperature Operation to - 30°C
- Fire Suppression
- Shadow detection
- Increased Cut-In
- Aviation Lights
- Aviation Markings on the Blades
- Vestas InteliLight®

ANNUAL ENERGY PRODUCTION



Assumptions
One wind turbine, 100% availability, 0% losses, k factor =2,
Standard air density = 1.225, wind speed at hub height

Vestas Wind Systems A/S
Hedeager 42 . 8200 Aarhus N . Denmark
Tel: +45 9730 0000 . Fax: +45 9730 0001
vestas@vestas.com . **vestas.com**

09/2017-EN

Appendix F

Detailed Construction Estimate Assumptions

Wind Farm Estimate – Detail

1.1 Construct WTG Sites and Crane Pads

The price estimate for the construction of the WTG sites and crane pads includes the following:

a) Clearing and grubbing of all vegetation as required for the completion of the work;
b) Civil mobilization and restoration of disturbed areas including culverts, erosion and sediment control measures;
c) Supply and construction of compacted aggregate crane pads. The crane pads will meet the minimum requirements of the turbine supplier technical specification;
d) Preparation and implementation of project site drainage in accordance with the environmental requirements and storm drainage plan and applicable laws;
e) Construction and clearing activities may include top soil stripping, site excavation, soil compaction, erosion and sedimentation control, as well as site reclamation and grading;
f) Seeding and re-vegetation are excluded.

1.2 Construct Laydown and Trailer Area

The price estimate for the laydown construction and trailer area includes:

a) Supply and construction of a site lay down area beside each WTG location for the temporary storage of WTG components and equipment. The storage of WTG components will meet the turbine supplier requirements;
b) Supply and construction of a single, gravelled site lay down area for temporary storage of balance of plant equipment and to provide a location for the temporary main site office trailers.

1.3 Improve Existing Roads and Construct New Roads

Existing roads are assumed to need varying degrees of upgrades in order to accommodate transport of construction materials and equipment to the substation and turbine sites.

The bases of the estimate are as follows:
a) Adequate sub-soil conditions with limited gravel import;
b) All excavated material being left or used on site;
c) Reclamation and cleanup will involve topsoil placement and fine grading and contouring;
d) Brushing will be required;
e) Appropriate culvert drainage will be required;

f) Only one type of turbine access road has been assumed to provide access to turbine sites – 7.5m permanent right of way with 15m disturbance limit and temporary workspace;
g) Gravel surfaced road, crowned for runoff;
h) Roads will be constructed on the basis of a 10% maximum slope constraint and a 50 meter turning radius;
i) Additional work such as a towing assist by heavy machinery may be needed where potential road location grades are not suitable. Such additional costs are not included in this estimate;
j) An allowance to upgrade primary approach has been included.
k) Top soil stripping;
l) All erosion control measures including maintenance and silt fencing;
m) Maintenance of roads as required during construction up to the Substantial Completion of Contractor's Work;
n) Dust Control, as necessary, for the duration of work;
o) Localized dewatering from surface runoff;
p) Roads will be built with native materials found inside the project limit when possible;
q) Seeding and re-vegetation.

1.4 Foundations

The basis of estimate is listed below:
a) Based on raft-type turbine foundations as well as foundations of substation, MET tower and O&M building;
b) Based on adequate soil conditions;
c) Excavation and backfill;
d) Formwork and rebar;
e) Foundation waterproofing;
f) Supply as well as installation of listed quantities;
g) Grounding is included.
h) Excluded materials and services include P&H foundations, piles, rock anchors, rammed aggregates piers (geo piers), structural backfill, for unsuitable soil conditions, soil replacement, hazardous wastes, and well point for dewatering.

1.5 Turbine and Installation

High level, indicative turbine costs are included in this estimate. Turbines and auxiliary equipment will be supplied through an agreement between NL Hydro and the turbine supplier. New Colliers has assumed that all required rigging tools will be provided by the turbine supplier to meet their installation requirements. Any provisions for third party testing or inspections, outside of tool calibration certifications submitted at the beginning of the project, are excluded. Turbine commissioning will be performed by the turbine supplier.

Based on recent project experience, the turbine erection and installation costs are estimated using the following:

a) A hub height of 105m;
b) Service lift installation is included;
c) Provision of supporting cranes and crews capable of offloading WTGs at turbine sites;
d) Supply and construction of fencing and gates;
e) Installation cost allows for 5 wind days;
f) Tower erection schedule is based on receiving one complete tower per day;
g) No allowance for late deliveries.

Revision may be required depending on conditions of TSA and determination of manufacturing.

1.6 Substation

The substation for Project A is a one transformer 138/34.5kV substation with four wind turbine circuits and one breaker set aside to connect VAR compensation systems.

1.7 Transmission System

A 3-breaker ring bus arrangement has been allowed for at the transmission POI. This may not be required based on final system impact studies.

1.8 Collection System

The collection system estimate is based on information and experience from previous projects and recent budget estimates, expressed in 2018 dollars. Prices of copper, steel, concrete, and labour are quite volatile and will affect the accuracy of these numbers. The lengths of all power lines were based on typical values from industry experience:

a) 34 kilometers of overhead collector system and 2 kilometres of underground collector system for Project A, 5.1 kilometers of overhead collector system and 200 metres of underground collector system for Project B,
b) Trenching and ground wire;
c) Riser poles to allow transition from underground circuits to overhead feeders;

1.9 SCADA/Communications

The SCADA and communications estimate was based on recent experience and includes.

a) Two permanent MET towers for Project A and zero permanent MET Towers for Project B were included in the estimate for use of power curve verification and warranty purposes.
b) The supply and installation of sixteen (16) aviation lights was included for Project A and three (3) aviation lights for Project B.

1.10 Miscellaneous Site Costs

Miscellaneous site costs include those costs associated with miscellaneous freight, storage and other site cost allowances that will be needed during construction such as surveying and snow removal. These site costs also take into account the cost of testing collectors, roads, foundations, as well as the substation and transmission line.

1.11 Engineering

Engineering rates were estimated based on an Engineer-Procure-Construct (EPC) project contracting methodology. The following disciplines are typically involved in the EPC engineering process:

Civil and Structural Engineering
- Access including roads
- Grading and drainage
- Foundation Design

Electrical Engineering
- Substation
- Transmission
- Collection System
- SCADA, Telecom

Project Management
Contracts Management
Procurement
Project Services

3.13 Construction Management

The estimate for construction management is based on recent experience and cost reviews and includes engineering support, site supervision, travel costs, site office with basic supplies and a safety officer.

Appendix G

NL Hydro Table

Preliminary Project Development and Construction Estimate - NL Hydro Table Format
07-Aug-18

System Adequacy Study Data Request - Wind Expansion

Instructions: In support of our system adequacy study, please fill out the following table as an input to the Plexos model
All costs should be in 2018 dollars, the model will escalate the costs automatically

Input		Unit	Notes
Plant Maximum Capacity	100.8	MW	
Unit Capacity	4.2	MW	
Number of Units	24	Units	
Average Annual Energy	353	GWh	
Construction Length	4	year	
Construction Cost	$189,313,900	$	Class 5 estimate
% Cost (Year 1)	0.3	%	Class 5 estimate
% Cost (Year 2)	0.6	%	Class 5 estimate
% Cost (Year 3)	28.2	%	Class 5 estimate
% Cost (Year 4)	70.9	%	Class 5 estimate
Variable O&M	1	$/MWh	Class 5 estimate
Fixed O&M	$6,048,000	$/year	Class 5 estimate
Maintenance Rate	6	days/year	Average per turbine, inclusive of planned and unplanned maintenance
Forced Outage Rate	1.5	%	Excludes planned and unplanned maintenance, even as related to forced outages

NEW COLLIERS LTD.

Preliminary Project Development and Construction Estimate - NL Hydro Table Format
07-Aug-18

System Adequacy Study Data Request - Wind Expansion

Instructions: In support of our system adequacy study, please fill out the following table as an input to the Plexos model
All costs should be in 2018 dollars, the model will escalate the costs automatically

Input		Unit	Notes
Plant Maximum Capacity	12.6	MW	
Unit Capacity	4.2	MW	
Number of Units	3	Units	
Average Annual Energy	44	GWh	
Construction Length	3	year	
Construction Cost	$28,996,620	$	Class 5 estimate
% Cost (Year 1)	1.3	%	Class 5 estimate
% Cost (Year 2)	14.5	%	Class 5 estimate
% Cost (Year 3)	84.2	%	Class 5 estimate
% Cost (Year 4)	0.0	%	Class 5 estimate
Variable O&M	1	$/MWh	Class 5 estimate
Fixed O&M	$882,000	$/year	Class 5 estimate
Maintenance Rate	6	days/year	Average per turbine, inclusive of planned and unplanned maintenance
Forced Outage Rate	1.5	%	Excludes planned and unplanned maintenance, even as related to forced outages

Attachment 6

Solar Generation Alternative

New Colliers Ltd.

NL Hydro Solar Generation Alternative

Project Development Estimate

November 2, 2018

Revision 1 – For Client Use

To: Alex Guilbeault, Newfoundland & Labrador Hydro

From: Laurie Murphy, New Colliers Ltd.

1 Scope

1.1 What is being considered

New Colliers Ltd. (New Colliers) has been engaged by Newfoundland and Labrador Hydro (NL Hydro) to provide support in the feasibility assessment and preliminary cost estimation for the development of solar projects on the island of Newfoundland.

This document describes the basis for a preliminary cost estimate for a 9.81MWDC/7.5MWAC solar project based in Newfoundland and Labrador. Two variations of the project were tested for comparative energy yield – Gander and Labrador City. Gander and Labrador City are expected to have larger commercial loads that the solar plants could be located close to, good availability of land and above-average solar regimes for the island of Newfoundland and in mainland Labrador, respectively.

NL Hydro did not provide specifications for the size of the solar array to be used for the study. Thus, New Colliers chose distribution-connected solar farms close to large industrial loads to minimize interconnection costs. There is an international airport adjacent to the proposed site in Gander and a hospital, college and mall adjacent to the proposed site in Labrador City.

1.2 Notable Omissions

The estimates attached as Appendix A include detailed breakdowns for the CapEx costs (also generally referred to as "construction costs" by NL Hydro). The estimate generally encompasses development, procurement, construction and commissioning costs.

No legal fees or costs associated with financing have been allowed for. No contingency has been included in these estimates.

2 Basis of Estimate

This is a preliminary, Class 5 cost estimate. The intent of this estimate is to assess the feasibility and high-level cost of solar project development in Newfoundland based on 2018 conditions.

The preliminary cost estimate is primarily based on experience with industry-normal costs from across Canada along with adjustments made for considerations of NL's specific development and construction environment.

Project Variants

Only one project size variant and cost estimate were considered and the pricing can be considered indicative for any NL community, with required amenities for construction, for a project size between two (2) and twenty (20) megawatts DC. Two preliminary project solar resource assessments were developed – one for Gander and one for Labrador City. Those results are contained in Appendices B and C, respectively.

Development

The following development costs have been allowed for in the project estimate:

- Development of a Solar Resource Assessment (SRA)
- A limited geotechnical investigation to sufficiently characterize the geotechnical conditions at site so as to allow for most competitive bidding by contractors and suppliers. The costs for a more detailed geotechnical investigation, to be undertaken by the Contractor, have been allowed for in the construction phase
- A limited site survey of key features, as required
- An allowance for land acquisition costs to the extent required for site investigative purposes
- Interconnection System Impact Study (SIS), Facility Study and applicable interconnection fee required to mobilize utility crews for required system upgrades
- An environmental impact assessment
- The internal costs associated with undertaking competitive bid processes for panel supply, construction contracting and competitive Power Purchase Agreement (PPA) pricing
- Internal engineering and management costs
- Owner's construction site representation
- Land rental costs during construction
- Development permits

Panel Supply and Delivery

Panels will be supplied and delivered to the project laydown area. Supporting structures and piling are assumed to have been constructed in advance, so as to minimize laydown area requirements. Costs for delivery are included.

Project Construction

Each project estimate includes the following scope:

- Panels will be 2m x 1m dimensions. The typical structure arrangement will be four landscape-oriented panels high and 28 panels wide
- Supply and installation of driven piles
- Supply and installation of steel mounting structures
- A low voltage collection system is run through cable trays mounted to supporting structures
- Construction of solar array pad;
- Testing of collection system and distribution interconnection
- Primarily summer and fall construction are envisioned
- Pre-commissioning and commissioning of balance-of-plant (BOP) systems
- Labour is competitively sourced
- Infrastructure for any future expansion is not included
- The estimate is based on July 2018 dollars (CAD$)
- Panel component receiving location assumed to be project laydown area adjacent to pad
- No allowance for excess material to be hauled off-site has been included
- No rock hammering or blasting has been allowed for. It is assumed an excavator will be able to rip any rock during excavation, if required
- No utility or water crossings have been allowed for
- Taxes and duties are not included
- Costs of copper, steel, aluminum, concrete and labour may fluctuate and affect the accuracy of this estimate
- It is assumed that the developer will enter into a single design-build contract for all the balance-of-plant (BOP) facilities (i.e. the balance of all infrastructure outside of the panels)
- High level estimates of Owner development costs are included
- Contingency is not included and should be applied at the discretion of NL Hydro

Relevant Notes on Estimates

The solar power industry has seen dramatically reduced solar panel prices in recent years (and even months), which is yielding increasingly low Levelized Cost of Energy (LCOE) estimates for new solar energy projects.

The reference pricing on which New Colliers has based their estimates has been delivered through competitive bid processes of sufficient size to attract a critical mass of interested, qualified and competitive bidders. The impact of any future tariffs or trade premiums has not been considered.

New Colliers notes that NL Hydro would be best able to achieve the costs estimated herein by conducting their own competitive solar energy generation procurement process with scale suitable to attract a critical mass of interest and investment from suppliers.

3 Technical

3.1 Location

NL Hydro has not nominated any specific sites for consideration. NL does not have one of the stronger solar resources in Canada (see Figure 1). However, given the sharply decreasing panel costs the market has been seeing, there may be economical sites in NL that have the benefit of diversifying NL's fuel mix and that may provide an opportunity to pair with energy storage solutions to provide dispatchable capacity. The cost of energy storage hasn't been included in this estimate.

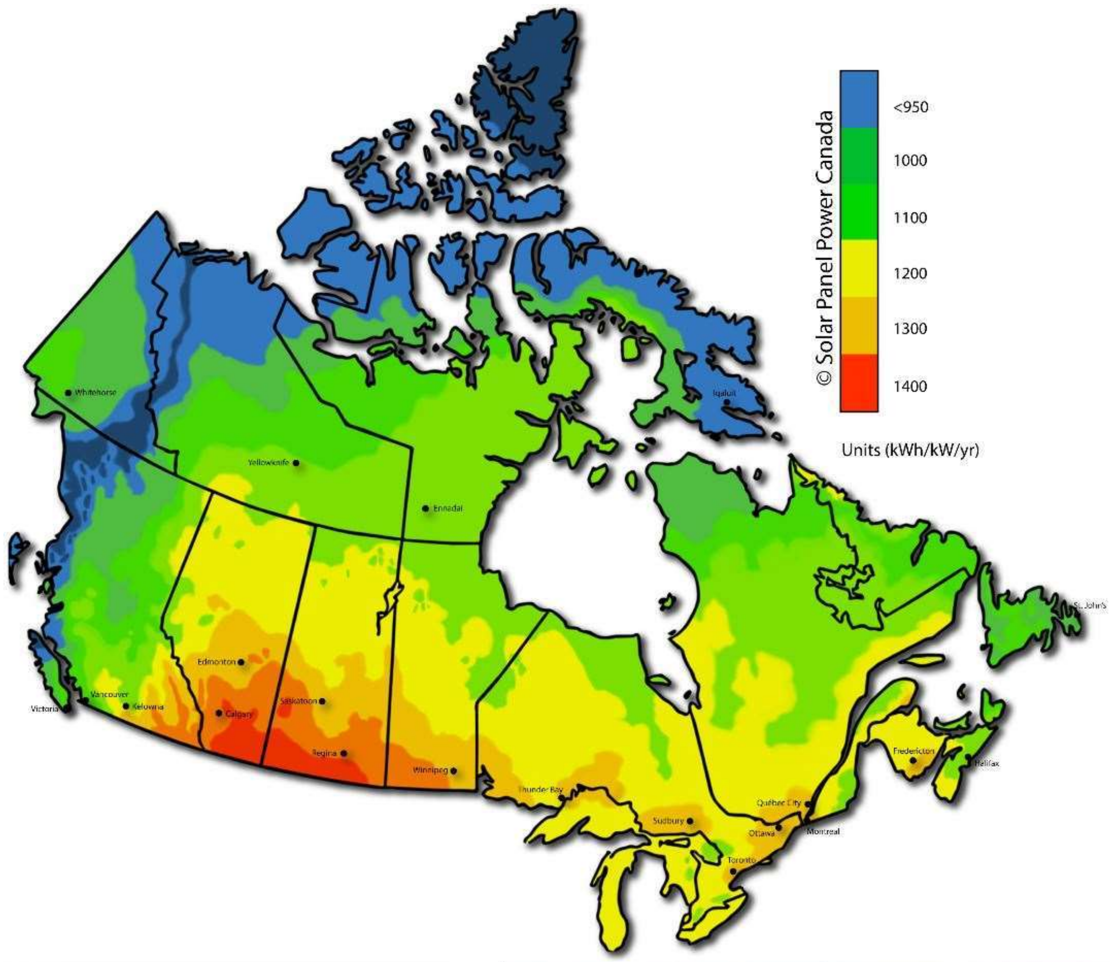


Figure 1: Estimated solar energy density, courtesy of Solar Panel Power Canada

New Colliers chose a representative Newfoundland site and a representative Labrador site to compare potential energy yields for the island vs. the mainland. High level data review and assessments showed Gander and Labrador City have an abundance of available land, larger commercial loads that the solar projects can be sited next to and average or above average solar resource for their region (see Figure 2). Projects were sited based on available satellite imagery in Google Earth. Site visits to any prospective site would need to take place to refine project layouts, construction estimates and site-specific project feasibility.

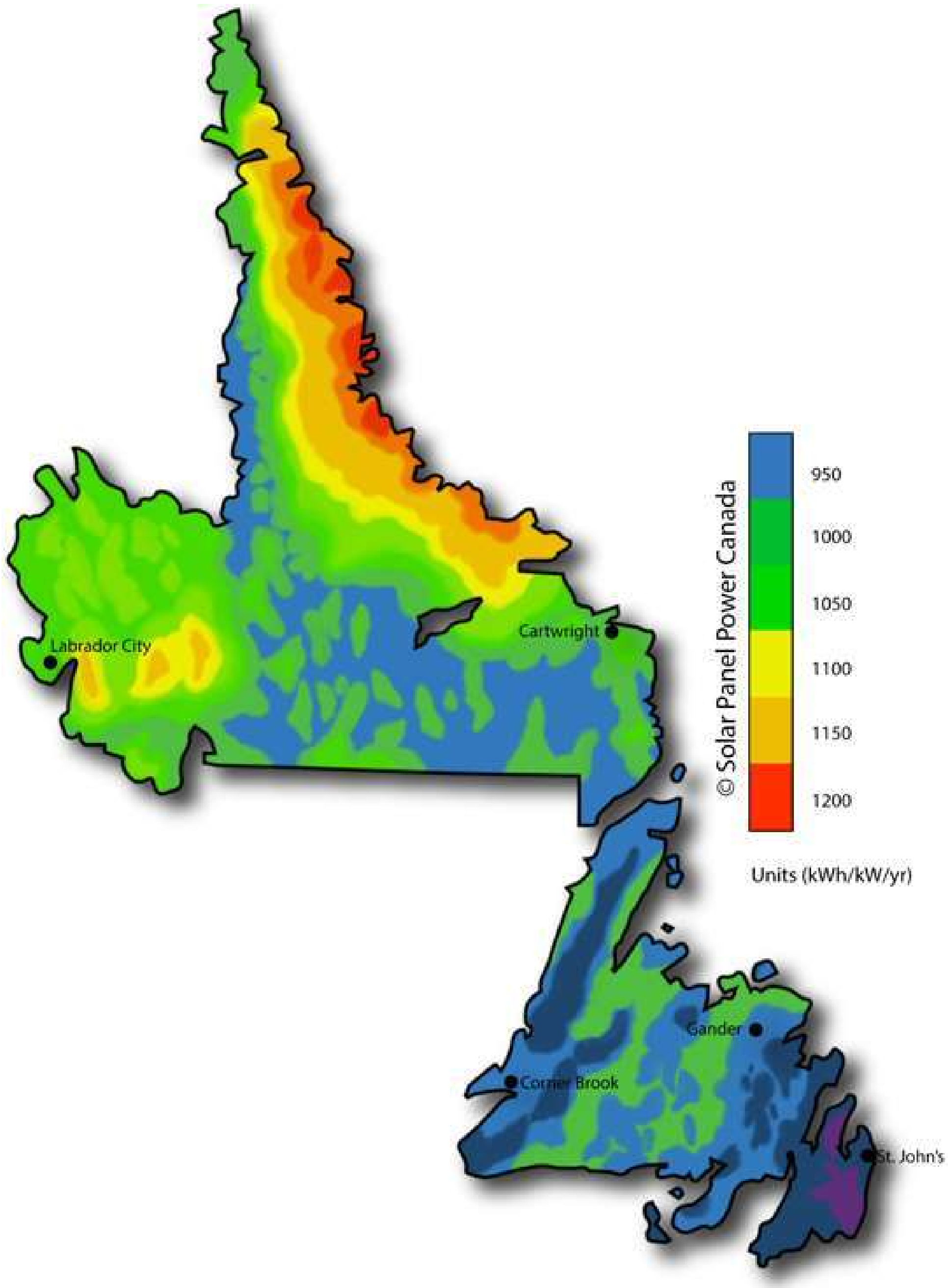


Figure 2: High level solar resource for NL (courtesy of Solar Panel Power Canada). Note, darker blue and purple colours (e.g. Avalon Peninsula) have capacity ratios lower than 950 kWh/KW/yr.

There are clearly opportunities to optimize site selection to target higher resource areas. However, construction costs, interconnection costs, operational costs and operational electrical losses may increase with more remote project locations. Locating an even larger scale solar project in an area of higher resource and close to a transmission system interconnection point may be worth exploring further.

Construction unit rates have not been differentiated between Labrador and Newfoundland and it can be said that the representative solar project site has the following characteristics:

- alongside a major road or highway
- within 500m of a three-phase distribution line with a capacity of 8MW
- wooded project area without shallow bedrock or wetlands within the project polygon
- with panels mounted on a south-facing pitch of available private or public lands subject to required consultation and approvals
- with panel components delivered to site in a staged fashion to allow minimization of laydown area sizing and orderly construction process

3.2 Size of Units

The Trina TSM-DE14A(II) 365W panel has been used for this estimate. The brochure for the panel is attached as Appendix E. The panels are arranged in landscape orientation on a structure allowing mounting of four panels high. Each structure group is envisioned as being 28 panels wide and 4 panels high. An example of the configuration envisioned is seen in Figure 3. The actual array size and height, the panel tilt angle and the panel azimuth angle are characteristics that can be optimized during detailed design to allow for most optimized production.

Figure 3: Four-panel high landscape arrangment (courtesy businessfeed.sunpower.com)

In practice, the final panel model will be the competitively offered panel model that provides the most attractive and reliable economics over the life of the project in consideration of capital cost, project-specific yield performance, forecasted project lifetime and forecasted project Operations and Maintenance (O&M) costs.

3.3 Characteristics

3.3.1 Efficiency

The capacity factor is estimated to be 12% for the Gander project and 15% for the Labrador City project during the first operational year (both capacity factors referenced to DC capacity). These capacity factors were estimated based on a preliminary simulation with Helioscope solar project modelling software. The simulation does consider actual site topography, latitude and solar regime to the extent allowed by the accuracy of the input data.

There may be opportunities to improve the efficiency and capacity factor by optimizing panel selection, site selection, configuration of strings and structures, panel tilt angle and panel azimuth angle. Also, the impacts of losses associated with snow and ice cover have not been specifically considered.

The performance of the solar panels is expected to degrade over time. This performance degradation has not been modelled or represented in the summary table numbers used for the NL Hydro model. A typical panel supplier warranty guarantees that annual capacity factor degradation will not exceed 1%. However, the 2012 National Renewable Energy Laboratory (NREL) study titled "Photovoltaic Degradation Rates — An Analytical Review" describes 0.5% annual degradation as being the median of their study. The baseline production of the Trina TSM-DE14A is summarized by the following I-V curves:

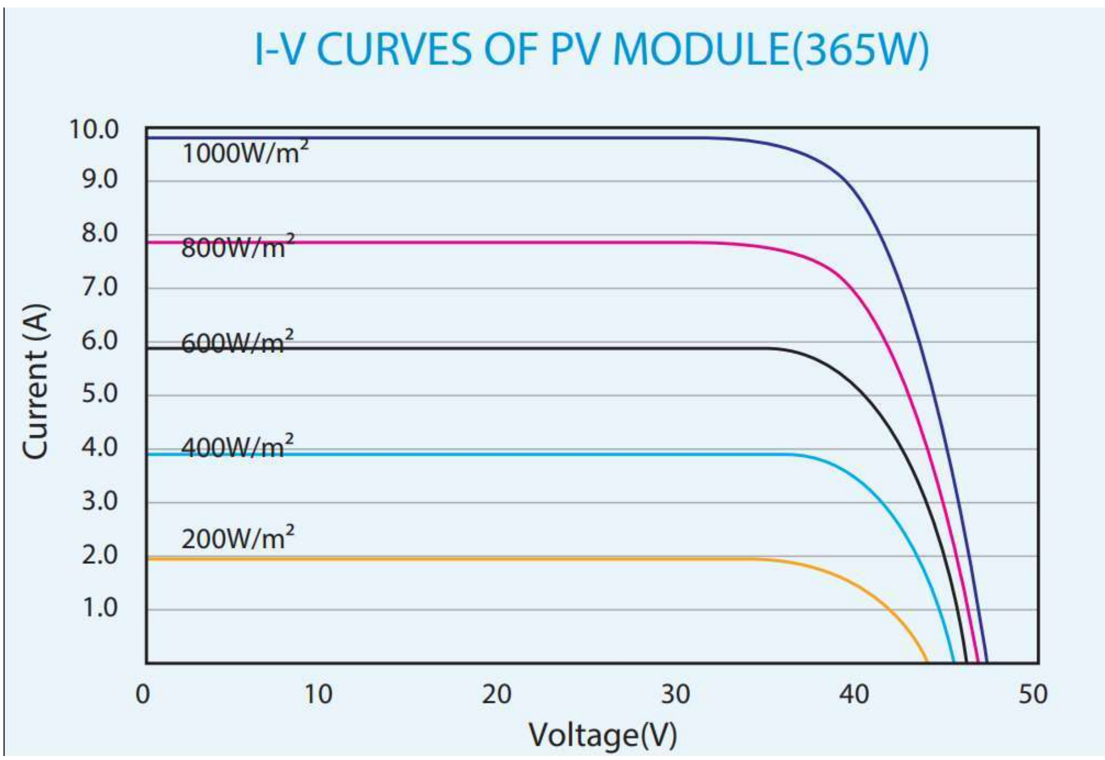


Figure 4: Trina I-V production curves for TSM-DE14A (courtesy Trina brochure)

4 Cost and Schedule

4.1 Capital Cost

Detailed project cost estimates can be found in Appendix A. The following cost summaries are reflective of a 3-year development and construction schedule.

4.2 Construction Schedule

For both the Gander and Labrador City variants, there is likely a two-year window required to complete key development activities. Developers will engage with stakeholders and conduct an environmental assessment based on a preliminary solar farm layout. Developers and the interconnecting utility will conduct a system impact study in year 1 and facility study in year 2 to assess the impact, cost and system modifications associated with interconnecting the new solar generating facility.

Preliminary geotechnical work and preliminary project designs will be completed to sufficiently inform a design-build bid package that will serve as the basis for a competitive and thorough contract procurement process. Also, in year two, panel down-payments will be made to initiate the panel supply process.

In year 3, construction activities will commence. All project construction activities can likely be completed in one year with the Commercial Operation Date (COD) in December of year 3.

4.3 O&M costs

It is expected that the project Owner will self-perform panel maintenance work. This will most typically include vegetation management, panel cleaning, panel snow-clearing, site access maintenance and snow clearing, collection system maintenance, project operational optimization and troubleshooting. It is expected that the developer will manage any third-party maintenance service contracts.

In addition to pure maintenance costs, developers will also have ongoing land lease costs to operate the project.

New Colliers believes that all these O&M activities can be completed for approximately $22,000/MWAC (per MW of rated AC capacity) per year in 2018 dollars. This estimate is based on the NREL 2018 Annual Technology Baseline estimates. New Colliers has estimated that operations can be carried out at approximately the same cost as some of the more expensive commercial and residential projects estimated for the US, but considerably more expensive than the estimates for utility scale solar operations.

We believe this to be a reasonable approach based on the current lack of a solar market and the demanding snow and ice conditions likely to be experienced by service crews. These costs are most likely achievable if the operator of the solar facility is shared with other operating facilities. As mentioned previously, implementing a larger solar power development strategy will allow for most competitive pricing for O&M services.

4.4 Environmental

Solar panels produce emissions-free energy over the operational life of the project and have a relatively low impact on their surroundings during the operational phase. As such, solar projects generally enjoy good levels of public acceptance and have relatively few environmental impacts and risks. Environmental assessment processes most commonly address the following key considerations:

- Visual impacts including glare
- Bird mortality
- Disturbance of wetlands or other key habitat

Proper siting of panels early in the development phase can typically reduce impacts associated with the above concerns and generally reduce the associated development and operational risks.

5 Feasibility

The solar power industry is still maturing in Canada. Technological advancements and the rapidly decreasing cost of solar panels have dramatically reduced the installation costs of solar projects to the point where they are comparable to wind projects.

Key development risks in Newfoundland and Labrador are likely to include:

- Adequacy of solar resource
- Access to suitable and publicly-acceptable land for the project
- Access to injection points on the grid that can accommodate generation with modest system upgrades and that are also close to strong solar resource project locations
- Design and resource constraints imposed by heavy snow load regimes
- Rock presence or other unknown site conditions that result in non-standard construction methods
- Increased costs associated with mitigating any of the impediments identified above

The solar resource in Newfoundland is not especially strong and new, larger scale solar generation projects may only now be commercially viable for independent power producers given the low panel supply cost. Solar technology generally pairs well with storage technologies. The advancement in battery storage technologies may further improve the viability of solar projects in Newfoundland.

There are regions in Labrador that do have good solar resource. Areas with good solar resource and larger loads, like Labrador West, as well as isolated communities looking to offset diesel costs, may make especially compelling cases for new solar project development in mainland Labrador - especially with the advancement of storage technologies.

Thus, it is expected that the key risks for solar project development are related to adequacy of resource in preferred development areas and potential cost overruns associated with building and operating a facility in a jurisdiction without an experienced workforce and with harsh weather and potentially challenging geology.

Construction costs have a relatively high risk for increase for Newfoundland and Labrador solar projects. It is expected that the following construction components have the highest potential for higher-than-estimated costs:

1) Possibility of sites having shallow rock that would increase costs for the array area, panel foundations and panel structures. The estimates developed by New Colliers assume that standard excavation techniques will suffice, with rock that can be ripped without needing to hammer or blast
2) Potential for labour costs to be higher than anticipated – The solar industry is not yet established in NL and it may be a challenge to find a large enough set of qualified and competitively-priced contractors willing to participate in a competitive bid process

Despite these project risks, New Colliers expects that new solar project developments in Newfoundland and Labrador do have potential for success if properly managed and executed. The case is stronger for Labrador than it is for Newfoundland at this time. Additional solar generation capacity would pair well with Newfoundland's already strong hydro resource. The abundant hydro resource can likely balance the variability of a substantial solar portfolio size.

And so, development of solar projects in NL would provide NL with an opportunity to:

- Diversify the local electricity fuel supply with a relatively non-contentious renewable fuel source
- Provide additional renewable energy export capability
- For the distribution-connected option, lessen loads on distribution feeders and reduce the need for distribution feeder upgrades should technologies, such as electric cars, drive future load growth
- Create resilient regional microgrids, when paired with storage, to provide a more resilient distribution system

Lawrence Murphy
LM:lm

Appendix A: 9.81 MW DC Estimate
Appendix B: Solar Resource and Design Report - Gander
AppendixC: Solar Resource and Design Report – Labrador City
Appendix D: Distribution SLD
Appendix E: Trina Solar TSM-DE14A(II) PERC MONO 365W Brochure
Appendix F: NL Hydro Summary Table

Appendix A

9.81 MWDC Estimate

Total Costs

	Year 1	Year 2	Year 3	Year 4	Cost
Development Activities	$204,750	$555,250	$585,000	$0	$1,345,000
Panel Supply		$1,079,232	$4,316,928		$5,396,160
BOP Construction and Commissioning			$12,167,836	$0	$12,167,836
Annual Subtotals	*$204,750*	*$1,634,482*	*$17,069,764*	*$0*	
				Project Cost	**$18,908,996**
				Project Cost per MW	**$1,927,287**

Development Activities

	Year 1	Year 2	Year 3	Year 4	Cost
No solar sensor deployment	$0	$0	$0		$0
Solar resource analysis	$20,000.0	$5,000			$25,000
Site surveying, preliminary geotechnical investigation	$2,250.00	$12,750			$15,000
Stakeholder consultation/engagement	$30,000.0	$30,000			$60,000
Land acquisition	$0.0	$25,000			$25,000
Interconnection studies, application and agreement	$15,000.00	$85,000			$100,000
Interconnection fee	$0.00		$150,000		$150,000
Environmental Impact Assessment	$37,500.0	$87,500			$125,000
Project contract procurement and PPA pricing	$70,000.0	$280,000			$350,000
Inhouse engineering, project management and oversi	$30,000	$30,000	$120,000		$180,000
Construction management	$0	$0	$165,000		$165,000
Land rental during construction	$0	$0	$25,000		$25,000
Permits and licenses	$0	$0	$125,000		$125,000
Annual Subtotals	*$204,750*	*$555,250*	*$585,000*	*$0*	
				Development Cost	**$1,345,000**
				Development Cost per MW	**$137,088**

Panel Supply and Delivery

	Year 2	Year 3	Cost
26880 Trina Solar TSM-DE14A(II) PERC MONO 365W	$1,079,232	$4,316,928	$5,396,160
		Panel Cost	**$5,396,160**
		Panel Cost per MW	**$550,000**

Balance-of-Plant (BOP) Construction Estimate

Construct Laydown and Trailer Area				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Excavate and Backfill Trailer Area	1	each	$ 50,000.00	$ 50,000.00
Reclamation of Temporary Area	1	LS	$ 50,000.00	$ 50,000.00
			Subtotal	$ 100,000.00
Improve Existing Roads				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Improve Existing Roads	0	m	$ 100.00	$ -
Allowance for improved major approaches	2	each	$ 20,000.00	$ 40,000.00
			Subtotal	$ 40,000.00
Construct New Roads and Drainage				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Wood Cutting and Grubbing	0.1	Ha	$ 9,000.00	$ 900.00
Construct new roads	100	m	$ 120.00	$ 12,000.00
Roads maintenance and reclamation	100	m	$ 40.00	$ 4,000.00
			Subtotal	$ 16,900.00
Solar Array Site Preparation				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Wood Cutting and Grubbing	28.75	Ha	$ 9,000.00	$ 258,729.30
Surface excavation, backfill and pad prep	25.14	Ha	$ 10,000.00	$ 251,427.00
Reclamation allowance	1	Unit	$ 10,000.00	$ 10,000.00
			Subtotal	$ 520,156.30
Piling and Structures Supply and Install				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Piling and Structures	6720	Piles w/structures	$ 949.00	$ 6,377,280.00
			Subtotal	$ 6,377,280.00
Panel Installation				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Panel mounting	26880	Panel	$ 25.00	$ 672,000.00
No tracking motors	0	Motors	$ 5,000.00	$ -
			Subtotal	$ 672,000.00
Inverter, SCADA and Transformer				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Inverter supply and installation	60	Inverters	$ 35,000.00	$ 2,100,000.00
SCADA and monitoring	1	LS	$ 100,000.00	$ 100,000.00
Transformers and protection	20	Xfrms	$ 50,000.00	$ 1,000,000.00
			Subtotal	$ 3,200,000.00
Distribution Interconnection				
	Quantity	**Unit**	**Unit Rate**	**Cost**
25kV Interconnection line	0.5	km	$ 225,000.00	$ 112,500.00
Civil Works	1	LS	$ 15,000.00	$ 15,000.00
Foundation and Grounding Works	1	LS	$ 15,000.00	$ 15,000.00
Electrical Equipment	1	LS	$ 250,000.00	$ 250,000.00
VAR Compensation	1	Allowance	$ -	$ -
Installation and testing	1	LS	$ 50,000.00	$ 50,000.00
			Subtotal	$ 442,500.00
Misc. Site Costs				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Surveying	1	LS	$ 15,000.00	$ 15,000.00
Commissioning Collectors, Panels	1	LS	$ 30,000.00	$ 30,000.00
Testing for Roads and Foundations	1	LS	$ 25,000.00	$ 25,000.00
Allowance for O&M building costs	1	LS	$ 25,000.00	$ 25,000.00
Fencing	2080	lm	$ 50.00	$ 104,000.00
			Subtotal	$ 199,000.00

Balance-of-Plant (BOP) Construction Estimate (Continued)					
		Contractor Engineering			
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Civil Engineering including Foundation	1	LS	$ 50,000.00	$ 50,000.00	
Collection System and LV Engineering	1	LS	$ 20,000.00	$ 20,000.00	
Inverter and Interconnection Engineering	1	LS	$ 50,000.00	$ 50,000.00	
Geotech Study	1	LS	$ 20,000.00	$ 20,000.00	
			Subtotal	$ 140,000.00	
		Contractor Construction Management			
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Staff and Management	8	Months	$ 25,000.00	$ 200,000.00	
Temporary Installation Including Power and Comms	8	Months	$ 25,000.00	$ 200,000.00	
Health and Safety	8	Months	$ 7,500.00	$ 60,000.00	
			Subtotal	$ 460,000.00	
			Total	$ 12,167,836.30	
			BOP Cost Per MWDC	$ 1,240,198.58	
			BOP Cost Per MWAC	$ 1,624,660.14	

Appendix B

Solar Resource and Design Report - Gander

HelioScope

Annual Production Report produced by Lawrence Murphy

Gander Airport 2 Sample Newfoundland, James Blvd gander

Report

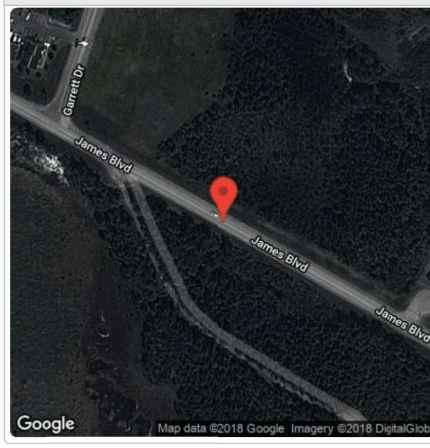
Project Name	Sample Newfoundland
Project Description	Gander-based solar installation
Project Address	James Blvd gander
Prepared By	Lawrence Murphy lmurphy@newcolliers.com

New Colliers Ltd.

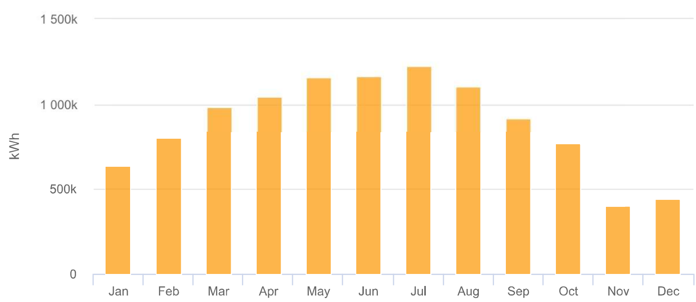
System Metrics

Design	Gander Airport 2
Module DC Nameplate	9.81 MW
Inverter AC Nameplate	0 Load Ratio:
Annual Production	10.65 GWh
Performance Ratio	85.7%
kWh/kWp	1,085.3
Weather Dataset	TMY, Gander Int'l, WYEC2-B-14509 (epw)
Simulator Version	e4f6e998e5-5bf11868b3-51cd59abab-cd01acd920

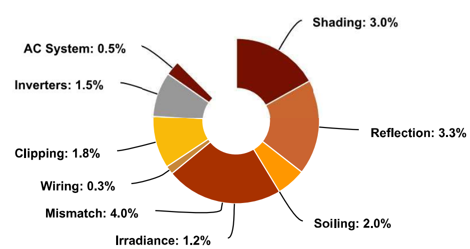
Project Location



Monthly Production



Sources of System Loss



Annual Production

	Description	Output	% Delta
Irradiance (kWh/m²)	Annual Global Horizontal Irradiance	1,082.4	
	POA Irradiance	1,266.1	17.0%
	Shaded Irradiance	1,228.5	-3.0%
	Irradiance after Reflection	1,188.1	-3.3%
	Irradiance after Soiling	1,164.3	-2.0%
	Total Collector Irradiance	**1,164.3**	**0.0%**
Energy (kWh)	Nameplate	11,451,442.5	
	Output at Irradiance Levels	11,316,273.6	-1.2%
	Output at Cell Temperature Derate	11,563,372.5	2.2%
	Output After Mismatch	11,101,313.2	-4.0%
	Optimal DC Output	11,068,998.5	-0.3%
	Constrained DC Output	10,868,055.8	-1.8%
	Inverter Output	10,702,000.0	-1.5%
	Energy to Grid	**10,648,500.0**	**-0.5%**
Temperature Metrics			
	Avg. Operating Ambient Temp		6.6 °C
	Avg. Operating Cell Temp		12.1 °C
Simulation Metrics			
		Operating Hours	4413
		Solved Hours	4413

Condition Set

Description	Condition Set 1
Weather Dataset	TMY, Gander Int'l, WYEC2-B-14509 (epw)
Solar Angle Location	Meteo Lat/Lng
Transposition Model	Perez Model
Temperature Model	Sandia Model
Irradiation Variance	5%
Cell Temperature Spread	4° C
Module Binning Range	-2.5% to 2.5%
AC System Derate	0.50%

Temperature Model Parameters

Rack Type	a	b	Temperature Delta
Fixed Tilt	-3.56	-0.075	3°C
Flush Mount	-2.81	-0.0455	0°C

Soiling (%)

J	F	M	A	M	J	J	A	S	O	N	D
2	2	2	2	2	2	2	2	2	2	2	2

Module Characterizations

Module	Characterization
TSM-DE14A(II) PERC MONO 365 (Trina Solar)	Spec Sheet Characterization, PAN

Component Characterizations

Device	Characterization
SG 125HV (Sungrow)	Spec Sheet

HelioScope

Annual Production Report produced by Lawrence Murphy

Components

Component	Name	Count
Inverters	SG 125HV (Sungrow)	60 (7.50 MW)
Strings	10 AWG (Copper)	960 (116,529.8 m)
Module	Trina Solar, TSM-DE14A(II) PERC MONO 365 (365W)	26,880 (9.81 MW)

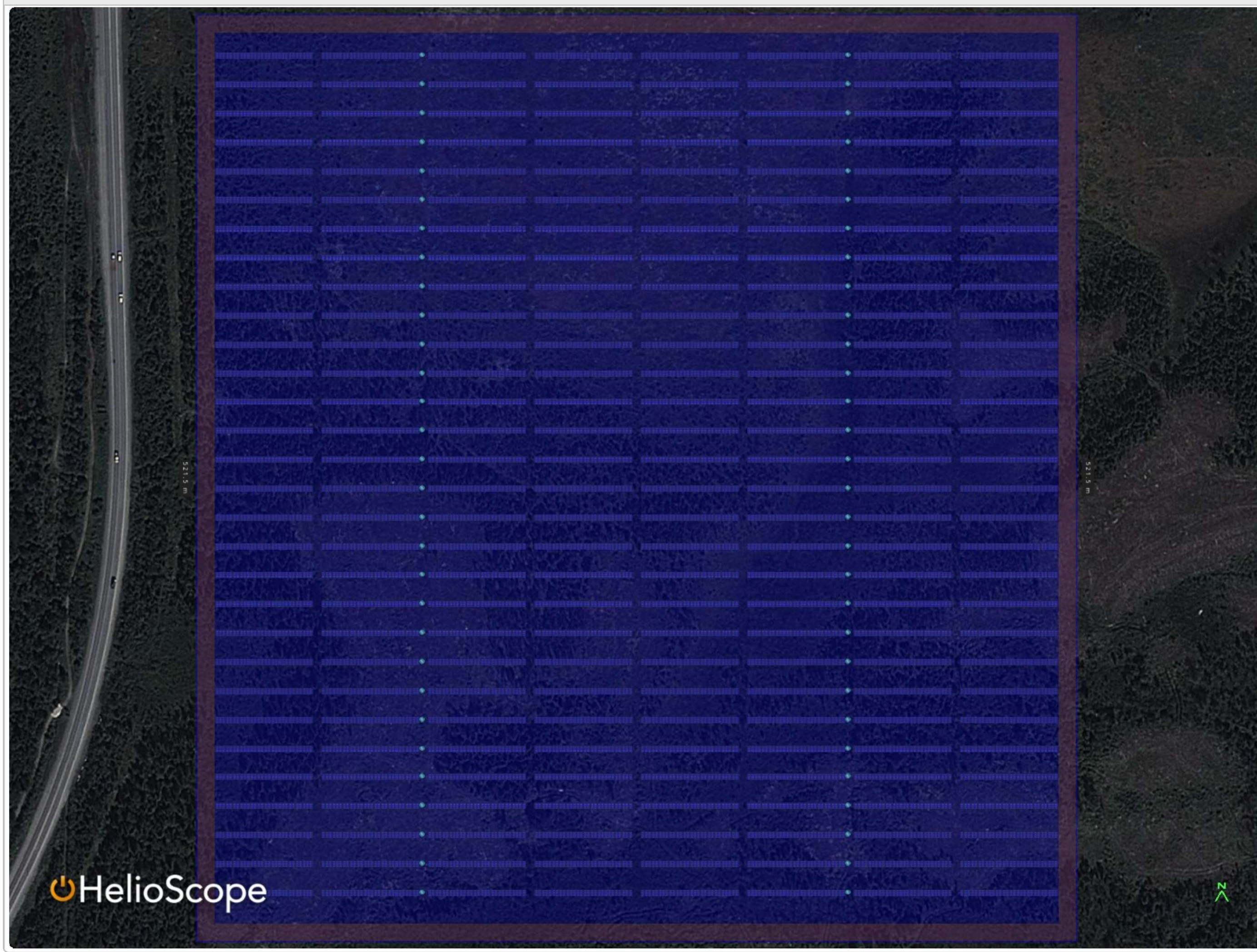
Wiring Zones

Description	Combiner Poles	String Size	Stringing Strategy
Wiring Zone	12	28-28	Along Racking

Field Segments

Description	Racking	Orientation	Tilt	Azimuth	Intrarow Spacing	Frame Size	Frames	Modules	Power
Field Segment 1	Fixed Tilt	Landscape (Horizontal)	35°	180°	13.0 m	4x28	240	26,880	9.81 MW

Detailed Layout



Appendix C

Solar Resource and Design Report – Labrador City

HelioScope

Annual Production Report produced by Lawrence Murphy

Labrador City Health Centre 2 Labrador City, 1700 Nichols-Adam Highway Labrador City, NL A2V 0B2

Report

Project Name	Labrador City
Project Description	Labrador City based solar project adjacent to hospital
Project Address	1700 Nichols-Adam Highway Labrador City, NL A2V 0B2
Prepared By	Lawrence Murphy lmurphy@newcolliers.com

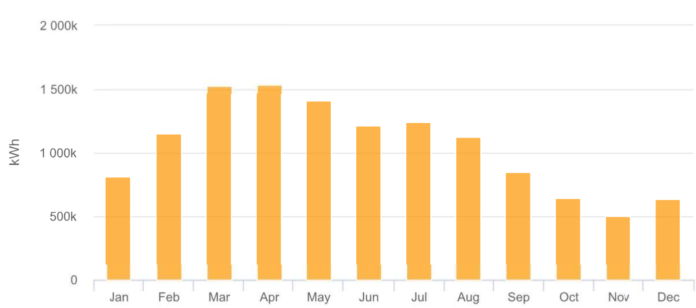
New Colliers Ltd.

System Metrics

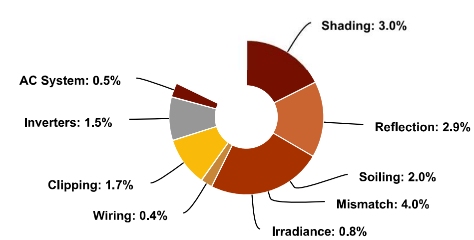
Design	Labrador City Health Centre 2
Module DC Nameplate	9.81 MW
Inverter AC Nameplate	0 Load Ratio:
Annual Production	12.61 GWh
Performance Ratio	86.9%
kWh/kWp	1,284.9
Weather Dataset	TMY, 10km Grid, meteonorm (meteonorm)
Simulator Version	e4f6e998e5-5bf11868b3-51cd59abab-cd01acd920

Project Location

Monthly Production



Sources of System Loss



Annual Production

	Description	Output	% Delta
Irradiance (kWh/m²)	Annual Global Horizontal Irradiance	1,122.7	
	POA Irradiance	1,477.8	31.6%
	Shaded Irradiance	1,434.0	-3.0%
	Irradiance after Reflection	1,393.1	-2.9%
	Irradiance after Soiling	1,365.2	-2.0%
	Total Collector Irradiance	**1,365.2**	**0.0%**
Energy (kWh)	Nameplate	13,412,455.5	
	Output at Irradiance Levels	13,301,002.9	-0.8%
	Output at Cell Temperature Derate	13,700,895.4	3.0%
	Output After Mismatch	13,147,545.6	-4.0%
	Optimal DC Output	13,093,869.8	-0.4%
	Constrained DC Output	12,866,488.2	-1.7%
	Inverter Output	12,670,100.0	-1.5%
	Energy to Grid	**12,606,700.0**	**-0.5%**
Temperature Metrics			
	Avg. Operating Ambient Temp		2.5 °C
	Avg. Operating Cell Temp		9.8 °C
Simulation Metrics			
	Operating Hours		4611
	Solved Hours		4611

Condition Set

Description	Condition Set 1
Weather Dataset	TMY, 10km Grid, meteonorm (meteonorm)
Solar Angle Location	Meteo Lat/Lng
Transposition Model	Perez Model
Temperature Model	Sandia Model

Temperature Model Parameters	Rack Type	a	b	Temperature Delta
	Fixed Tilt	-3.56	-0.075	3°C
	Flush Mount	-2.81	-0.0455	0°C

Soiling (%)	J	F	M	A	M	J	J	A	S	O	N	D
	2	2	2	2	2	2	2	2	2	2	2	2

Irradiation Variance	5%
Cell Temperature Spread	4° C
Module Binning Range	-2.5% to 2.5%
AC System Derate	0.50%

Module Characterizations	Module	Characterization
	TSM-DE14A(II) PERC MONO 365 (Trina Solar)	Spec Sheet Characterization, PAN

Component Characterizations	Device	Characterization
	SG 125HV (Sungrow)	Spec Sheet

HelioScope

Annual Production Report produced by Lawrence Murphy

Components

Component	Name	Count
Inverters	SG 125HV (Sungrow)	60 (7.50 MW)
Strings	10 AWG (Copper)	960 (189,273.0 m)
Module	Trina Solar, TSM-DE14A(II) PERC MONO 365 (365W)	26,880 (9.81 MW)

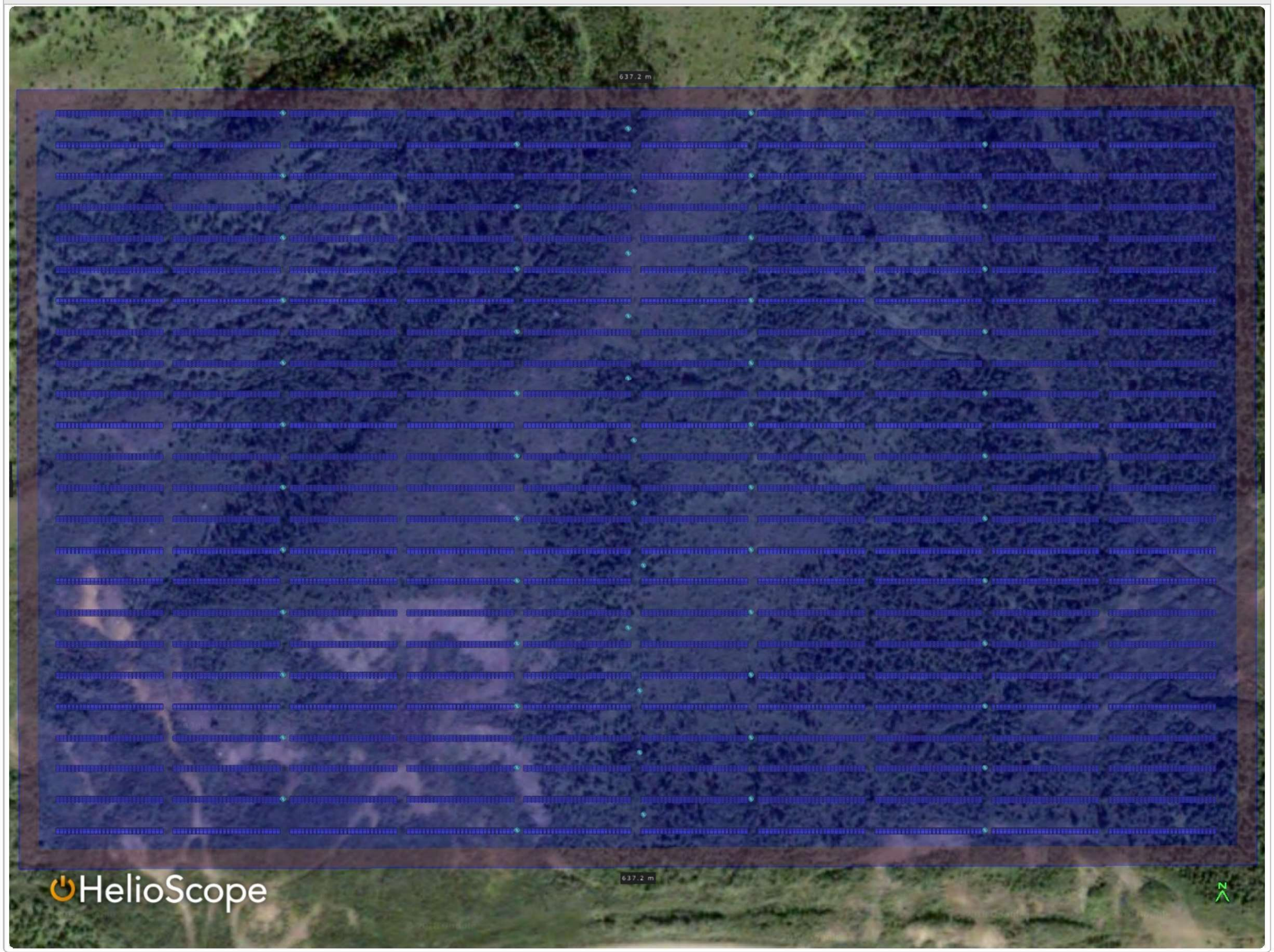
Wiring Zones

Description	Combiner Poles	String Size	Stringing Strategy
Wiring Zone	12	28-28	Along Racking

Field Segments

Description	Racking	Orientation	Tilt	Azimuth	Intrarow Spacing	Frame Size	Frames	Modules	Power
Field Segment 1	Fixed Tilt	Landscape (Horizontal)	40°	180°	13.0 m	4x28	240	26,880	9.81 MW

Detailed Layout

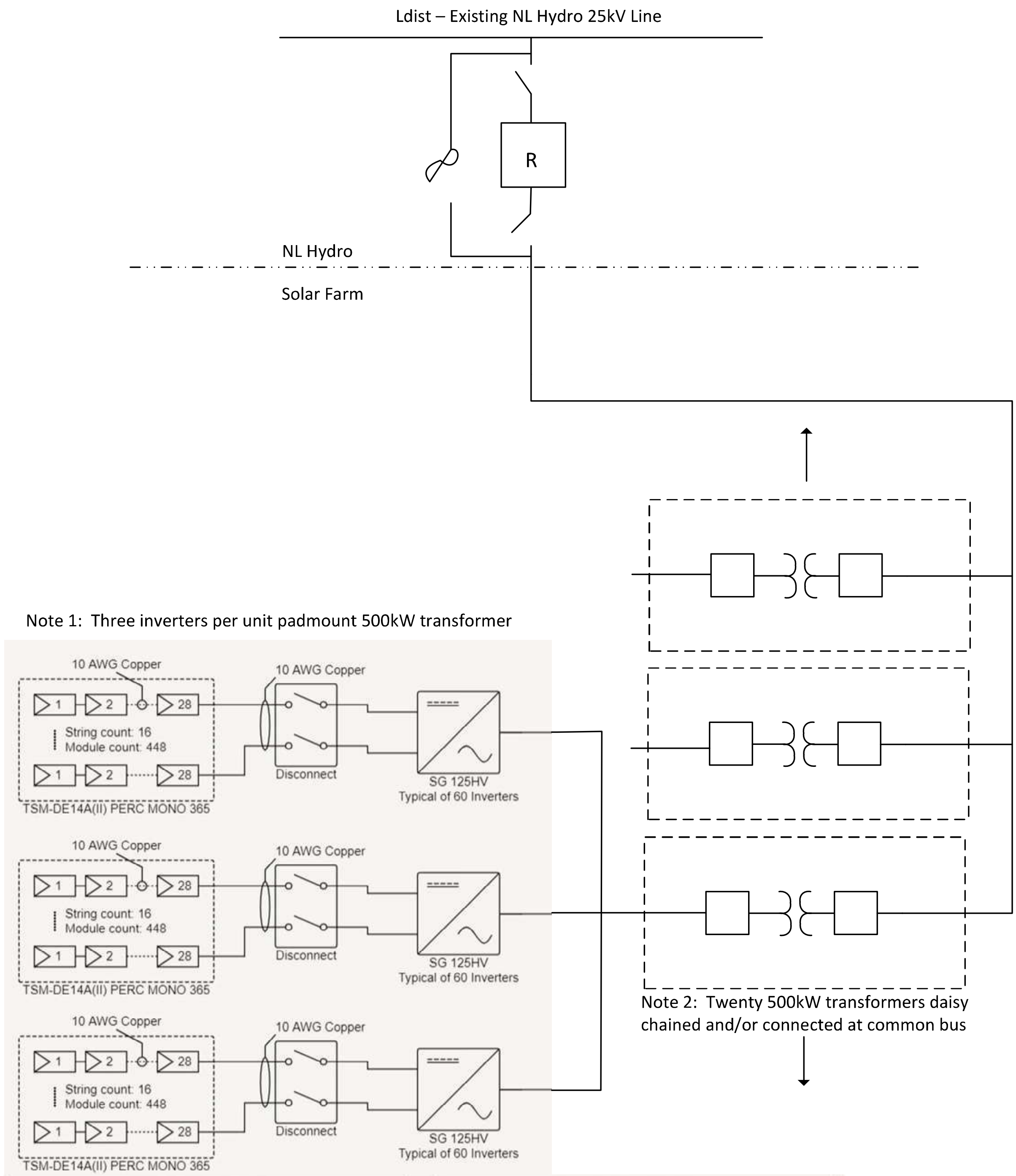


Appendix D

Distribution SLD

NEW COLLIERS LTD.

9.81MWDC/7.49MWAC Solar Project
25kV Distribution Interconnection Station
Preliminary Single Line Diagram
Rev. B – November 2, 2018



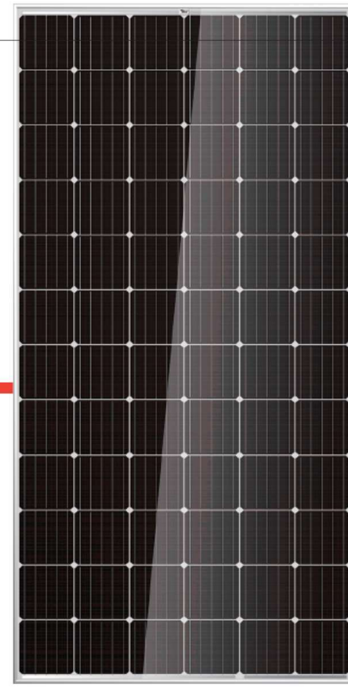
Module Specifications	
26880x Trina Solar TSM-DE14A(II) PERC MONO 365	
STC Rating	365 W
Vmp	39.3 V
Imp	9.3 A
Voc	48 V
Isc	9.77 A

Inverter Specifications	
60x Sungrow SG 125HV	
Max AC Power Rating	125 kW
Max Input Voltage	1,500 V
Min AC Power Rating	0 W
Min Input Voltage	860 V

Appendix E

Trina Solar TSM-DE14A(II) PERC MONO 365W Brochure

Mono Multi Solutions



THE TALLMAX M PLUS+

FRAMED 72-CELL MODULE (1500V)

72 CELL
MONOCRYSTALLINE MODULE

335-365W
POWER OUTPUT RANGE

18.8%
MAXIMUM EFFICIENCY

0~+5W
POSITIVE POWER TOLERANCE

Founded in 1997, Trina Solar is the world's leading comprehensive solutions provider for solar energy. we believe close cooperation with our partners is critical to success. Trina Solar now distributes its PV products to over 60 countries all over the world. Trina is able to provide exceptional service to each customer in each market and supplement our innovative, reliable products with the backing of Trina as a strong, bankable partner. We are committed to building strategic, mutually beneficial collaboration with installers, developers, distributors and other partners.

Comprehensive Products And System Certificates

IEC61215/IEC61730/UL1703/IEC61701/IEC62716
ISO 9001: Quality Management System
ISO 14001: Environmental Management System
ISO14064: Greenhouse gases Emissions Verification
OHSAS 18001: Occupation Health and Safety Management System

Trinasolar

Ideal for large scale installations

- Reduce BOS cost by connecting more modules in a string
- 1500V UL/1500V IEC certified

Maximize limited space with top-end efficiency

- Up to 188 W/m² power density
- Low thermal coefficients for greater energy production at high operating temperatures

Highly reliable due to stringent quality control

- Over 30 in-house tests (UV, TC, HF, and many more)
- In-house testing goes well beyond certification requirements
- 100% EL double inspection

Certified to withstand the most challenging environmental conditions

- 2400 Pa wind load
- 5400 Pa snow load

LINEAR PERFORMANCE WARRANTY

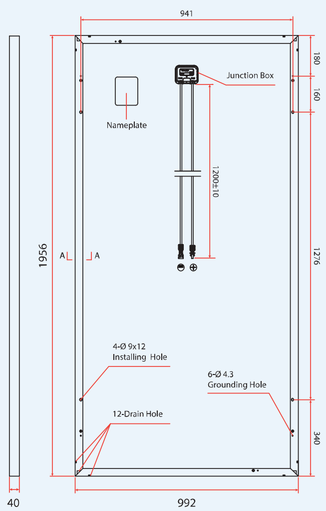
10 Year Product Warranty · 25 Year Linear Power Warranty

TALLMAX M plus

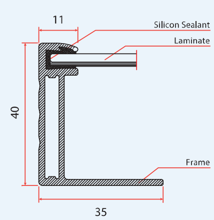
FRAMED 72-CELL MODULE (1500V)

PRODUCTS	POWER RANGE
TSM-DE14A(II)	335-365W

DIMENSIONS OF PV MODULE(mm)

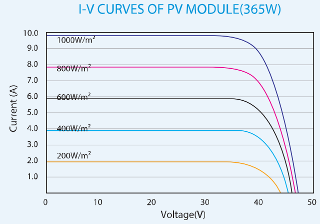


Back View

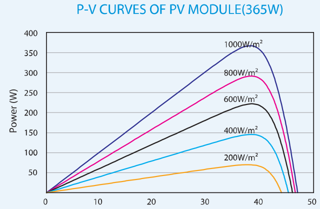


(A-A)

I-V CURVES OF PV MODULE(365W)



P-V CURVES OF PV MODULE(365W)



ELECTRICAL DATA (STC)

Peak Power Watts-P_{MAX} (Wp)*	335	340	345	350	355	360	365
Power Output Tolerance-P_{MAX} (W)	0 ~ +5						
Maximum Power Voltage-V_{MPP} (V)	37.9	38.2	38.4	38.5	38.7	38.9	39.1
Maximum Power Current-I_{MPP} (A)	8.84	8.90	9.00	9.09	9.17	9.26	9.35
Open Circuit Voltage-V_{OC} (V)	46.3	46.5	46.7	46.9	47.0	47.2	47.3
Short Circuit Current-I_{SC} (A)	9.36	9.45	9.50	9.60	9.69	9.79	9.88
Module Efficiency η_m (%)	17.3	17.5	17.8	18.0	18.3	18.5	18.8

STC: Irradiance 1000W/m², Cell Temperature 25°C, Air Mass AM1.5.
*Measuring tolerance: ±3%.

ELECTRICAL DATA (NOCT)

Maximum Power-P_{MAX} (Wp)	250	253	257	261	264	268	272
Maximum Power Voltage-V_{MPP} (V)	35.1	35.2	35.5	35.6	35.8	35.9	36.1
Maximum Power Current-I_{MPP} (A)	7.12	7.19	7.25	7.33	7.40	7.47	7.54
Open Circuit Voltage-V_{OC} (V)	43.1	43.2	43.4	43.5	43.7	43.8	43.9
Short Circuit Current-I_{SC} (A)	7.56	7.63	7.67	7.75	7.82	7.88	7.95

NOCT: Irradiance at 800W/m², Ambient Temperature 20°C, Wind Speed 1m/s.

MECHANICAL DATA

Solar Cells	Monocrystalline 156.75 × 156.75 mm (6 inches)
Cell Orientation	72 cells (6 × 12)
Module Dimensions	1956 × 992 × 40 mm (77.0 × 39.1 × 1.57 inches)
Weight	26.0 kg (57.3 lb) with 4.0 mm glass; 22.5 kg (49.6 lb) with 3.2 mm glass
Glass	4.0 mm (0.16 inches) for PERC Mono; 3.2 mm (0.13 inches) for Std Mono, High Transmission, AR Coated Tempered Glass
Backsheet	White
Frame	Silver Anodized Aluminium Alloy
J-Box	IP 67 or IP 68 rated
Cables	Photovoltaic Technology Cable 4.0mm² (0.006 inches²), 1200 mm (47.2 inches)
Connector	QC4 / TS4 (1500V)

TEMPERATURE RATINGS

NOCT(Nominal Operating Cell Temperature)	44°C (±2°C)
Temperature Coefficient of P_{MAX}	- 0.39%/°C
Temperature Coefficient of V_{OC}	- 0.29%/°C
Temperature Coefficient of I_{SC}	0.05%/°C

MAXIMUM RATINGS

Operational Temperature	-40~+85°C
Maximum System Voltage	1500V DC (IEC)
	1500V DC (UL)
Max Series Fuse Rating	15A

(DO NOT connect Fuse in Combiner Box with two or more strings in parallel connection)

WARRANTY

10 year Product Workmanship Warranty

25 year Linear Power Warranty

(Please refer to product warranty for details)

PACKAGING CONFIGURATION

Modules per box: 27 pieces

Modules per 40' container: 648 pieces

Trinasolar

CAUTION: READ SAFETY AND INSTALLATION INSTRUCTIONS BEFORE USING THE PRODUCT.

Version number: TSM_EN_2017_APAC_A www.trinasolar.com

Appendix F

NL Hydro Summary Table

NEW COLLIERS LTD.

Preliminary Project Development and Construction Estimate - NL Hydro Table Format
Nov 2, 2018

System Adequacy Study Data Request - Solar Development

Instructions:	In support of our system adequacy study, please fill out the following table as an input to the Plexos model All costs should be in 2018 dollars, the model will escalate the costs automatically

Input		Unit	Notes
Plant Maximum Capacity	7.49	MW	7.49MW AC, 9.81MW DC
Unit Capacity	0.000365	MW	365W individual modules
Number of Units	26880	Units	
Average Annual Energy	12.52	GWh	
Construction Length	3	year	
Construction Cost	$18,908,996	$	Class 5 estimate
% Cost (Year 1)	1.1%	%	Class 5 estimate
% Cost (Year 2)	8.6%	%	Class 5 estimate
% Cost (Year 3)	25.9%	%	Class 5 estimate
% Cost (Year 4)	0.0	%	Class 5 estimate
Variable O&M	1	$/MWh	Class 5 estimate
Fixed O&M	$164,780	$/year	Class 5 estimate
Maintenance Rate	1	days/year	Equipvalent of 2 half-day plant-wide planned outages
Forced Outage Rate	0.5	%	1.5 days related to grid or complete plant outages

Attachment 7

Battery Storage Alternative

NEW COLLIERS LTD.

NL Hydro Battery Storage Alternative

Project Development Estimate

November 2, 2018

Revision 0 – For Client Use

To: Alex Guilbeault, Newfoundland & Labrador Hydro
From: Laurie Murphy, New Colliers Ltd.

1 Scope

1.1 What is being considered

New Colliers Ltd. (New Colliers) has been engaged by Newfoundland and Labrador Hydro (NL Hydro) to provide support in the feasibility assessment and preliminary cost estimation for the development of battery storage projects on the island of Newfoundland.

This document describes the basis for a preliminary cost estimate for a 100MW/200MWh lithium ion battery storage solution located on the Avalon Peninsula.

With the decommissioning of the Holyrood generating facility planned for 2021, the Avalon Peninsula will be without its largest generating station. New Colliers understand that the Avalon Peninsula will be connected to the rest of the island via two 230kV AC transmission lines and one HVDC line. The 613MW Bay D'Espoir hydro generating station will be the closest large-scale generating station to the Avalon Peninsula with an estimated 250km of 230kV line between the Bay D'Espoir generating station and the Solider's Pond station.

The DC link from Labrador to the island will frequently be delivering a high proportion of the total power to the island and a disturbance and/or temporary outage on this, or another major line may have the potential to disrupt portions of the island system, especially loads on the Avalon Peninsula. New Colliers has considered these factors in the development of this report and estimate. New Colliers understands from NL Hydro that the system is likely to have an abundance of energy over the long term and this feasibility level assessment is intended to explore how a battery storage system might support any short-term power shortfall in contingency situations.

Evaluation of a battery storage system is sensible in that pricing for battery systems is rapidly declining and legacy performance issues are being addressed and remedied. A battery system can be deployed at most accessible sites and can be situated at optimal grid interconnection points, without the same considerations of required topography for uses like hydro and wind facilities. Also, quite importantly, battery storage solutions provide a faster response to grid contingency events than their combustion turbine counterparts. There may be other suitable solutions for energy storage technologies, but an estimate of development costs for those options is not undertaken here. Other alternatives are presented in Section 3.3.2 for reference.

Based on New Colliers' preliminary examination of average and seasonal peak loads (available from an August 2014 Nalcor information share related to Muskrat Falls), New Colliers believes that a review and estimate of large-scale battery capacity is appropriate for preliminary evaluation of a battery storage solution. Based on the size of the largest existing battery storage installations, New Colliers has chosen a 100MW/200MWh battery storage project for estimate and evaluation. If higher capacities are required, NL Hydro can study multiple deployments of the 100MW/200MWh solution at select areas of the island. Also, shorter duration reserves may be studied (e.g. one-hour reserve instead of two-hour) to improve economics.

1.2 Notable Omissions

The estimates attached as Appendix A include detailed breakdowns for the CapEx costs (also generally referred to as “construction costs” by NL Hydro). The estimate generally encompasses development, procurement, construction and commissioning costs.

No legal fees or costs associated with financing have been allowed for. No contingency has been included in these estimates.

2 Basis of Estimate

This is a preliminary, Class 5 cost estimate. The intent of this estimate is to assess the feasibility and high-level cost of battery storage projects in Newfoundland based on 2018 conditions.

The preliminary cost estimate is primarily based on budgetary pricing from HICO and considers inputs from the document "US Battery Storage Market Trends – U.S. Energy Information Administration (EIA)" from May 2018 as well as insights gained from broader industry research.

Project Sizing

Based on 2014 information made available by Nalcor as part of the public consultation process for the Muskrat Falls project, the average winter load on the Avalon Peninsula is 557MW. Thus, it is expected that significant capacity may be required on the Avalon Peninsula during major contingency situations, such as the loss of the Labrador Island Link. New Colliers is not aware of any system studies that have defined the MW or MWh contingency needs of NL Hydro at this time, so we have used best judgment to define a suitable study case.

New Colliers chose a 100MW/200MWh project size as this is as large as the current largest installed global project. Tesla has installed a 100MW/129MWh battery storage project at the Hornsdale wind project near Adelaide, Australia. However, some larger projects are in the planning and permitting stages, particularly in California. Pacific Gas & Electric Co., for example, is seeking approval for 300MW and 182.5MW projects, among others, in California.

This 100MW/200MWh project can also be deployed at multiple locations or in conjunction with other storage technologies to give higher levels of reserve capacity and energy should more detailed studies prove those scenarios to be required or most feasible. New Colliers expects that dividing this 100MW/200MWh project into blocks to be concurrently deployed on the Avalon Peninsula would have similar costs per MW and per MWh. However, the cost of deploying smaller, one-off installations should be revisited if that deployment philosophy is pursued.

A more detailed discussion of deployment options is discussed in Section 3.

Development

The following development costs have been allowed for in the project estimate:

- Development of a needs identification study
- A limited geotechnical investigation to sufficiently characterize the geotechnical conditions at site to allow for most competitive bidding by contractors and suppliers. The costs for a more detailed geotechnical investigation, to be undertaken by the Contractor, have been allowed for in the construction phase
- A limited site survey of key features, as required
- An allowance for land acquisition costs to the extent required for site investigative purposes
- Interconnection System Impact Study (SIS), Facility Study and applicable interconnection fee required to mobilize utility crews for required system upgrades
- An environmental impact assessment
- The internal costs associated with undertaking competitive bid processes for battery system supply, construction contracting and competitive Power Purchase Agreement (PPA) pricing
- Internal engineering and management costs
- Owner's construction site representation
- Land rental costs during construction
- Development permits

Battery System Supply and Delivery

Battery system containers will be supplied and delivered to the project laydown area. Foundations are assumed to have been constructed in advance, to minimize laydown area requirements. Costs for delivery are included.

Project Construction

Each project estimate includes the following scope:

- Each 2MW battery container is estimated to be approximately 14m x 2.5m. Each 4MW battery power conditioning container is estimated to be approximately 14m x 2.5m.
- Installation of fenced battery array pad;
- Installation of reinforced concrete pads for container mounting
- A low voltage collection system is expected to be run underground with penetrations through pads to allow terminations at containers and AC equipment

- Battery storage system is assumed to be interconnected to the 66kV or 69kV bus of an existing NL Hydro substation. Costs to expand the existing substation have been allowed for.
- Testing of collection system and substation interconnection
- Primarily summer and fall construction are envisioned
- Pre-commissioning and commissioning of battery storage systems
- Competitively sourced labour
- Infrastructure for any future expansion is not included
- The estimate is based on August 2018 dollars (CAD$)
- No allowance for excess material to be hauled off-site has been included
- No rock hammering or blasting has been allowed for. It is assumed an excavator will be able to rip any rock during excavation, if required
- No utility or water crossings have been allowed for
- Taxes and duties are not included
- Costs of copper, steel, aluminum, concrete and labour may fluctuate and affect the accuracy of this estimate
- It is assumed that the developer will enter into a single design-build contract for all the balance-of-plant (BOP) facilities (i.e. the balance of all infrastructure outside of the battery system components)
- High level estimates of Owner development costs are included
- Contingency is not included and should be applied at the discretion of NL Hydro

Relevant Notes on Estimates

The battery storage industry is relatively young and is still seeing dramatically reduced battery prices year over year, with major cost reductions still projected in the coming years. There are several battery chemistries and technologies to choose from, but lithium ion technologies are the most widely deployed. According to the EIA study cited previously, "over 80% of U.S. large-scale battery storage power capacity is currently provided by batteries based on lithium-ion chemistries. "

As such, New Colliers has chosen to base the estimate on a lithium ion technology as supplied by HICO. Other chemistries may provide competitive benefits and those benefits can be explored during a subsequent investigation phase. For the purposes of this feasibility estimate, it is believed that a lithium ion solution provides a sound basis to evaluate preliminary project economics and performance.

3 Technical

3.1 Location

NL Hydro has not nominated any specific sites for consideration. However, interconnection at an existing major substation is a sensible basis on which to proceed. The Holyrood Generating Station, Western Avalon or Oxen Pond substations all appear to have 66kV/69kV buses to which a new battery storage project may be feasibly interconnected. This assumption should be verified in a subsequent phase of study. Alternatively, interconnection to the 25kV or 35kV bus of an existing or new wind project may provide for the most economical interconnection.

It may be that the solution that meets the capacity requirements of NL Hydro involves either a larger battery system than the 100MW/200MWh estimated here or multiple 100MW/200MWh installations at different substations across the Avalon Peninsula. The estimate presented here can be scaled according to the capacity required for preliminary feasibility purposes. However, both the single larger installation and, to a lesser degree, multiple 100MW/200MWh installations, would benefit from economies of scale.

3.2 Size of Units

HICO has provided a sample layout derived from a 10MW/20MWh project that provides some of the basis of the estimate herein. It is estimated that a 100MW/200MWh project can be supplied through 45-foot containerized modules with individual capacities of 2MW/4MWh. The Battery Management System (BMS), Power Management System (PMS) and Power Conditioning System (PCS) are expected to be supplied in separate 45-foot containers that have the capacity to support two 2MW/4MWh battery container modules. A sample layout for the conceptual 10MW/20MWh portion is provided as Appendix B to this report.

3.3 Characteristics

3.3.1 Efficiency

The HICO product literature states that the round-trip efficiency of their ESS offering is more than 85%. 85% is in-line with industry expectations for lithium ion roundtrip efficiencies although efficiencies up to 90% are reported with some technologies. Degradation of efficiency has not been specifically modeled by New Colliers. However, an annual “augmentation” cost has been allowed for to replace those units whose performance degrades below acceptable thresholds.

3.3.2 Performance Benefits and Comparisons

As discussed, battery storage can provide capacity in contingency situations. Battery storage can also provide many other services and benefits to the grid. Subject to a more in-depth system implementation study, those potential benefits could include:

- Resource adequacy during non-contingency peak times
- Frequency regulation
- Voltage support
- Black start support
- Congestion relief
- Deferral of transmission and/or distribution upgrades
- Firming of variable generations such as wind and solar

While battery storage can provide emergency capacity reserve and other ancillary services, providing frequency regulation and voltage support in non-contingency situations, for example, may reduce the reserve capacity of the battery system should a contingency situation arise. For this reason, the fine balance of providing ancillary services and reserve capacity must be carefully planned and controlled. With that said, the lifetime of lithium ion batteries may also be reduced if the batteries are kept at 100% charge for extended periods of time. A detailed study should be undertaken to characterize this control balance in a subsequent phase of feasibility analysis.

While lithium ion technologies are the most broadly deployed battery type in North America, there are other potentially viable options on the market, both battery-based and using other technologies. While lead-acid batteries are commonly deployed for smaller scale applications, New Colliers believes flow batteries are the most likely alternative to lithium ion at the grid scale.

Lithium ion battery systems are desirable because of their high efficiency ratings and fast response times. They also have a relatively high energy density (i.e. take up less space) than some other battery chemistries.

Flow batteries are also a focus as an emerging technology. They are constructed with battery chemicals in a storage tank. While they have a lower energy density than lithium ion batteries (i.e. they take up more space), in projects where space is not a restriction, the tank size can be adjusted to provide additional energy capability, as required. In this respect, they may have some economies-of-scale advantages that can be leveraged to provide a lower cost per MWh in larger installations. The battery fluids for flow batteries can be corrosive or toxic. But on a positive note, fluids in the tank can be replaced to reinvigorate the battery over the project life.

Flow batteries have potential for lower capital costs in some use cases but they also have lower efficiencies as compared to lithium ion. Lithium ion batteries are also expected to provide faster response for power applications but have, historically, been capable of fewer charge-discharge cycles resulting in a shorter useful life. This requires the allowance for additional capital cost or additional sustaining capital expenditures to maintain the performance over a 20-year project life for the lithium ion option.

The technologies around these battery chemistries continue to rapidly evolve and actual competitive offerings of competing battery chemistries should be analyzed to assess the relative performance capability closer to the time of any planned deployment.

4 Cost and Schedule

4.1 Capital Cost

Detailed project cost estimates can be found in Appendix A. The following cost summaries are reflective of a 3-year development and construction schedule.

Cost Centre	Year 1	Year 2	Year 3	Year 4	Cost Centre Subtotals
Owner/Development Activities	$239,750	$645,250	$585,000	$0	$1,470,000
Battery Supply		$33,720,000	$134,880,000		$168,600,000
BOP Construction and Commissioning			$5,880,280	$0	$5,880,280
Annual Subtotals	*$239,750*	*$34,365,250*	*$141,345,280*	*$0*	

Project Cost	**$175,950,280**
Project Cost per MW	**$1,759,503**

Table 1 - Cost Summary for 100MW/200MWh Battery Storage Project

4.2 Construction Schedule

Independent of battery technology chosen, there is likely a two-year window required to complete key development activities. Developers will engage with stakeholders and conduct an environmental assessment based on a preliminary battery system layout. Developers and the interconnecting utility will conduct a system impact study in year 1 and facility study in year 2 to assess the impact, cost and system modifications associated with interconnecting the new battery storage generating facility.

Preliminary geotechnical work and preliminary project designs will be completed to sufficiently inform a design-build bid package that will serve as the basis for a competitive and thorough contract procurement process. Also, in year two, battery system down-payments will be made to initiate the battery system supply process.

In year 3, construction activities will commence. All project construction activities can likely be completed in one year with the Commercial Operation Date (COD) in December of year 3.

4.3 O&M costs

It is expected that the project Owner will self-perform battery system maintenance work. Basic maintenance will most typically include site access maintenance and snow clearing, collection system maintenance, project operational optimization and troubleshooting. It is expected that the developer will manage any third-party maintenance service contracts.

Operators will need to replace any battery units whose efficiency degrades beyond acceptable levels. This cost item is captured as augmentation cost in Table 2. Only a nominal augmentation cost of 0.5% of capital cost is allowed for in this estimate. New Colliers believes this is reasonable as we do not expect this plant to be used like a peaking power plant where it is frequently cycled with a significant depth of discharge. Further, it is expected that much of the system frequency regulation will be handled by NL Hydro's existing converter stations and hydro generation facilities in regular operating conditions. Based on the expected low cycling duty on the batteries, these costs could be even lower. These costs are difficult to estimate at this preliminary stage of study, especially without a system study defining the need and use cases. A detailed system study must be completed to give confidence to these numbers.

In addition to pure operations and/or maintenance costs, owners will also have ongoing land lease and insurance costs to operate the project.

New Colliers estimates the following annual operational costs in 2018 dollars:

Operations Cost Item		Cost
Staff		$150,000
Maintenance & equipment use		$250,000
Land lease		$20,000
Insurance		$75,000
Battery system augmentation		$843,000
Total		**$1,338,000**

Table 2 - Battery Storage System Estimated Annual Operations Costs

With limited industry history from which to draw, operational costs for battery storage likely present the highest degree of uncertainty in the cost estimate.

4.4 Environmental

Battery storage technologies provide the means to increase the proportion of renewable energy on the grid. In addition, they are expected to have a relatively low impact on their surroundings during the construction and operational phases of the project.

A battery field the size of the one proposed here (approximately 1 hectare) is a significant industrial installation. However, required civil work is expected to be minimal, the installation has very low relative height and the project can be located adjacent to an existing substation. Thus, a battery project such as the one proposed is expected to enjoy good levels of public acceptance and have relatively few environmental impacts and risks. Environmental assessment processes are likely to address the following key considerations:

- Containment and recycling of heavy metals and electrolyte materials
- Disturbance of wetlands or other key habitats during construction and operation

Potential environmental impacts of a lithium ion battery storage solution are expected to be very manageable.

5 Feasibility

Large-scale battery storage projects are relatively new in North America. The EIS market trends report estimates that, as of 2017, the total installed capacity of large-scale battery storage is 708MW/867MWh. In Canada, New Colliers is only aware of the Basin 1 and Basin 2 projects which were due to come online in the spring of 2018. They are designed for a total capacity of 4MW/12MWh. Clearly, the industry is quite young in North America, but the potential performance and economics are quite appealing.

Key development risks in Newfoundland are likely to include:

- Due to limited industry history, a relatively higher level of uncertainty in battery life and associated uncertainty in lifetime maintenance and augmentation costs
- Currently a lack of accurate projections for system need and battery system response with Holyrood being decommissioned and new Muskrat Falls coming online. This refined characterization would eventually form the basis of any storage system design
- Potential lack of access to cost-effective injection points on the grid that can accommodate new storage capacity with modest system upgrades

It is understood that NL Hydro is exploring the addition of new capacity to mitigate any potential negative system stability effects associated with the decommissioning of the Holyrood Generating Station. New combustion turbines, new renewable generation, new storage capacity or some combination of these technologies are most likely the strongest candidates to make up any future shortfall in capacity in contingency situations. While the implementation a newer technology such as battery storage will come with its challenges, implementation of a battery storage system makes sense for NL Hydro for several reasons:

1) It is expected that NL Hydro will have access to surplus energy in the near future given the strong hydro generation portfolio to soon be supplemented by the commissioning of Muskrat Falls. The access to market priced energy to charge the batteries is likely to compare favourably with the uncertainty in fuel pricing for a new combustion turbine generating station that might be an alternative for new capacity
2) In general, battery systems can respond faster and more accurately than thermal generation plants. This would be especially important in grid contingency situations like a disruption to one of the DC connections to the island or any of the DC or AC connections to the Avalon Peninsula

3) Battery systems (as well as other storage systems) can provide full negative and positive capacity for regulation (i.e. through charging and discharging) in contrast to traditional combustion turbines
4) Newfoundland has a very strong wind resource and new wind projects paired with storage would help to firm capacity from wind generation and allow NL Hydro to draw upon the grid supporting capability of both the battery system as well as modern full-converter type wind turbines. Combining new wind and storage may also provide for better economics for the interconnection portion of the new projects. The storage can be interconnected at 35kV instead of 66/69kV. Supplementary interconnection facilities at the point of interconnection (such as a three-breaker ring bus) may be avoided or the costs shared across a larger project.

For next steps, New Colliers recommends that NL Hydro:

1) Quantifies the need for capacity so that a storage solution may be refined in terms of size and intended use. Criteria such as the total storage time required (e.g. 10 minutes to 4 hours) and the degree to which NL Hydro would like the storage system to provide grid support functions such as frequency and voltage regulation (in addition to reserve capacity) will help refine the characteristics and cost of the storage system
2) Develop a more refined model that more accurately defines expected frequency of battery cycling, depth of discharge, etc. Operational costs can be refined on this basis
3) Engage suppliers in a more focused pricing exercise based on the outcome of the activities above
4) Attempt to identify lower costs points of interconnection on the grid than the 66/69kV points assumed herein

Laurie Murphy
LM:lm

Appendix A: 100MW/200MWh Estimate
Appendix B: Sample HICO Arrangement for 10MW/20MWh Project
Appendix C: Interconnection SLD
Appendix D: HICO ESS Product Literature
Appendix E: NL Hydro Summary Table

Appendix A

100MW/200MWh Estimate

Total Costs

	Year 1	Year 2	Year 3	Year 4	Cost
Development Activities	$239,750	$645,250	$585,000	$0	$1,470,000
Battery System Supply		$33,720,000	$134,880,000		$168,600,000
BOP Construction and Commissioning			$0	$0	$5,880,280
Annual Subtotals	*$239,750*	*$34,365,250*	*$135,465,000*	*$0*	
				Project Cost	**$175,950,280**
				Project Cost per MW	**$1,759,503**

Development Activities

	Year 1	Year 2	Year 3	Year 4	Cost
System needs forecasting	$40,000.0	$10,000			$50,000
Site surveying, preliminary geotechnical investigation	$2,250.00	$12,750			$15,000
Stakeholder consultation/engagement	$30,000.0	$30,000			$60,000
Land acquisition	$0.0	$25,000			$25,000
Interconnection studies, application and agreement	$30,000.00	$170,000			$200,000
Interconnection fee			$150,000		$150,000
Environmental Impact Assessment	$37,500.0	$87,500			$125,000
Project contract procurement and capacity pricing	$70,000.0	$280,000			$350,000
Inhouse engineering, project management and oversight	$30,000	$30,000	$120,000		$180,000
Construction management	$0	$0	$165,000		$165,000
Land rental during construction	$0	$0	$25,000		$25,000
Permits and licenses	$0	$0	$125,000		$125,000
Annual Subtotals	*$239,750*	*$645,250*	*$585,000*		
				Development Cost	**$1,470,000**
				Development Cost per MW	**$14,700**

Battery System Supply and Delivery

	Year 2	Year 3	Cost
HICO ESS Battery System	$33,720,000	$134,880,000	$168,600,000
		Battery System Cost	**$168,600,000**
		Battery System Cost per MW	**$1,686,000**

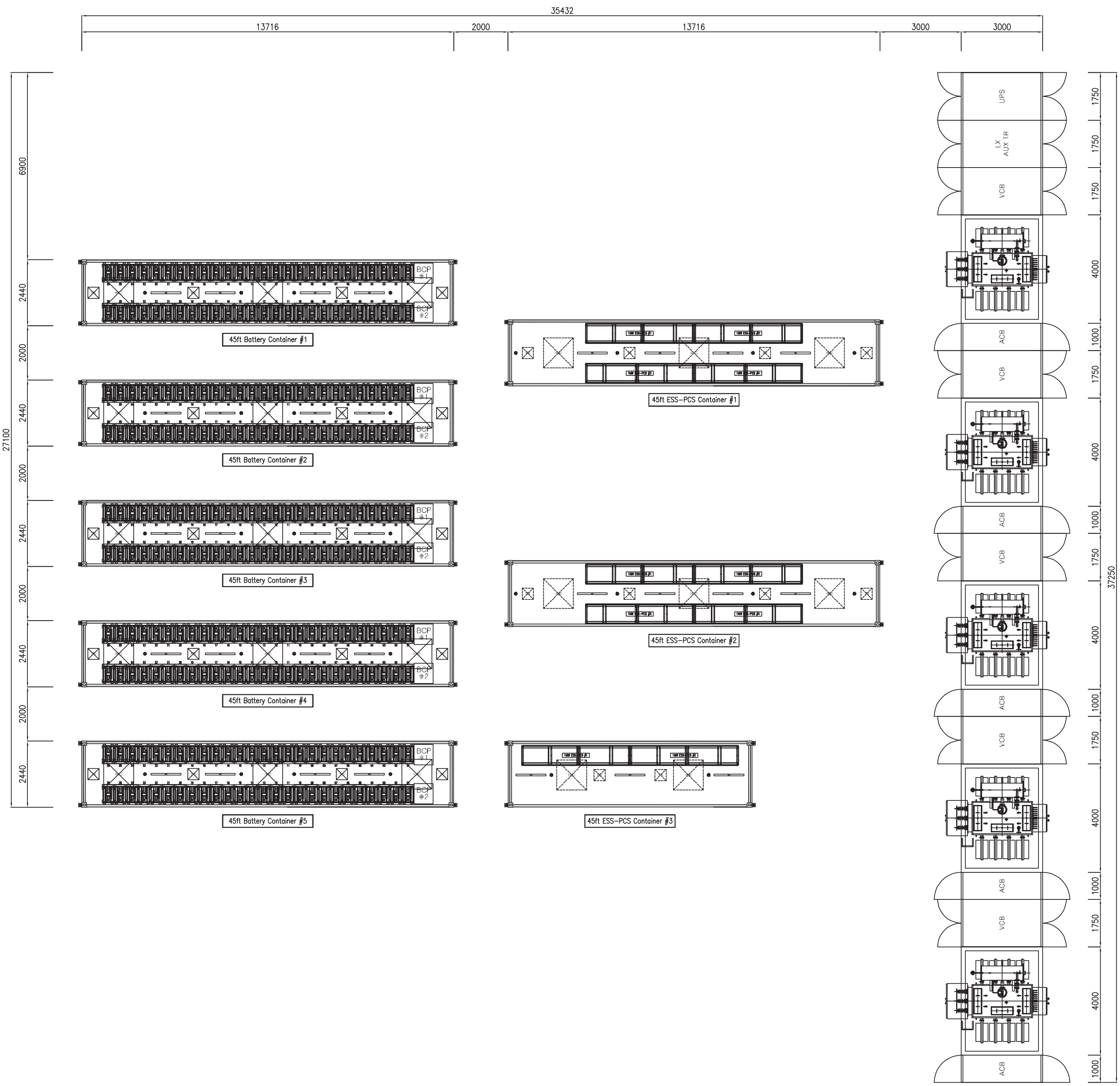
Balance-of-Plant (BOP) Construction Estimate

Construct Laydown and Trailer Area				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Excavate and Backfill Trailer Area	1	each	$ 50,000.00	$ 50,000.00
Reclamation of Temporary Area	1	LS	$ 50,000.00	$ 50,000.00
			Subtotal	$ 100,000.00
Improve Existing Roads				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Improve Existing Roads	0	m	$ 100.00	$ -
Allowance for improved major approaches	1	each	$ 20,000.00	$ 20,000.00
			Subtotal	$ 20,000.00
Construct New Roads and Drainage				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Wood Cutting and Grubbing	0.1	Ha	$ 9,000.00	$ 900.00
Construct new roads	100	m	$ 120.00	$ 12,000.00
Roads maintenance and reclamation	100	m	$ 40.00	$ 4,000.00
			Subtotal	$ 16,900.00
Battery Container Array Site Preparation				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Wood Cutting and Grubbing	0.99	Ha	$ 9,000.00	$ 8,930.25
Surface excavation, backfill and pad prep	0.95	Ha	$ 10,000.00	$ 9,450.00
Reclamation allowance	1	Unit	$ 10,000.00	$ 10,000.00
			Subtotal	$ 28,380.25
Container Foundations				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Container Foundations	85	each	$ 7,500.00	$ 637,500.00
			Subtotal	$ 637,500.00
DC Equipment Installation				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Container mounting and grounding	85	each	$ 7,500.00	$ 637,500.00
DC external wiring	85	each	$ 4,000.00	$ 340,000.00
			Subtotal	$ 977,500.00
AC Equipment Supply and Installation				
	Quantity	**Unit**	**Unit Rate**	**Cost**
20 MW transformer supply and installation	5	each	$ 250,000.00	$ 1,250,000.00
Low voltage breakers	5	each	$ 50,000.00	$ 250,000.00
69kV feeder breakers	5	each	$ 150,000.00	$ 750,000.00
Main 69kV breaker	1	each	$ 175,000.00	$ 175,000.00
Auxiliary power, UPS and other controls	5	each	$ 50,000.00	$ 250,000.00
			Subtotal	$ 2,675,000.00
69kV Substation Bus Interconnection				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Substation yard and fence additions	1	each	$ 100,000.00	$ 100,000.00
Bus extension	1	each	$ 100,000.00	$ 100,000.00
Protection settings adjustment	1	each	$ 50,000.00	$ 50,000.00
Foundation and grounding Works	1	each	$ 30,000.00	$ 30,000.00
			Subtotal	$ 280,000.00
Miscellaneous Site Costs				
	Quantity	**Unit**	**Unit Rate**	**Cost**
Surveying	1	LS	$ 10,000.00	$ 10,000.00
Commissioning	1	LS	$ 250,000.00	$ 250,000.00
Testing for Pads and Foundations	1	LS	$ 25,000.00	$ 25,000.00
Fencing	300	lm	$ 100.00	$ 30,000.00
			Subtotal	$ 315,000.00

Balance-of-Plant (BOP) Construction Estimate (Continued)					
		Contractor Engineering			
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Civil Engineering including Foundation	1	LS	$ 50,000.00	$ 50,000.00	
DC Collection System and LV Engineering	1	LS	$ 50,000.00	$ 50,000.00	
AC Collection and Interconnection Engineering	1	LS	$ 250,000.00	$ 250,000.00	
Geotech Study	1	LS	$ 20,000.00	$ 20,000.00	
			Subtotal	$ 370,000.00	
		Contractor Construction Management			
	Quantity	**Unit**	**Unit Rate**	**Cost**	
Staff and Management	8	Months	$ 25,000.00	$ 200,000.00	
Temporary Installation Including Power and Comms	8	Months	$ 25,000.00	$ 200,000.00	
Health and Safety	8	Months	$ 7,500.00	$ 60,000.00	
			Subtotal	$ 460,000.00	
			Total	$ 5,880,280.25	
			BOP Cost Per MW	$ 58,802.80	
			BOP Cost Per MWh	$ 29,401.40	

Appendix B

Sample HICO Arrangement for 10MW/20MWh Project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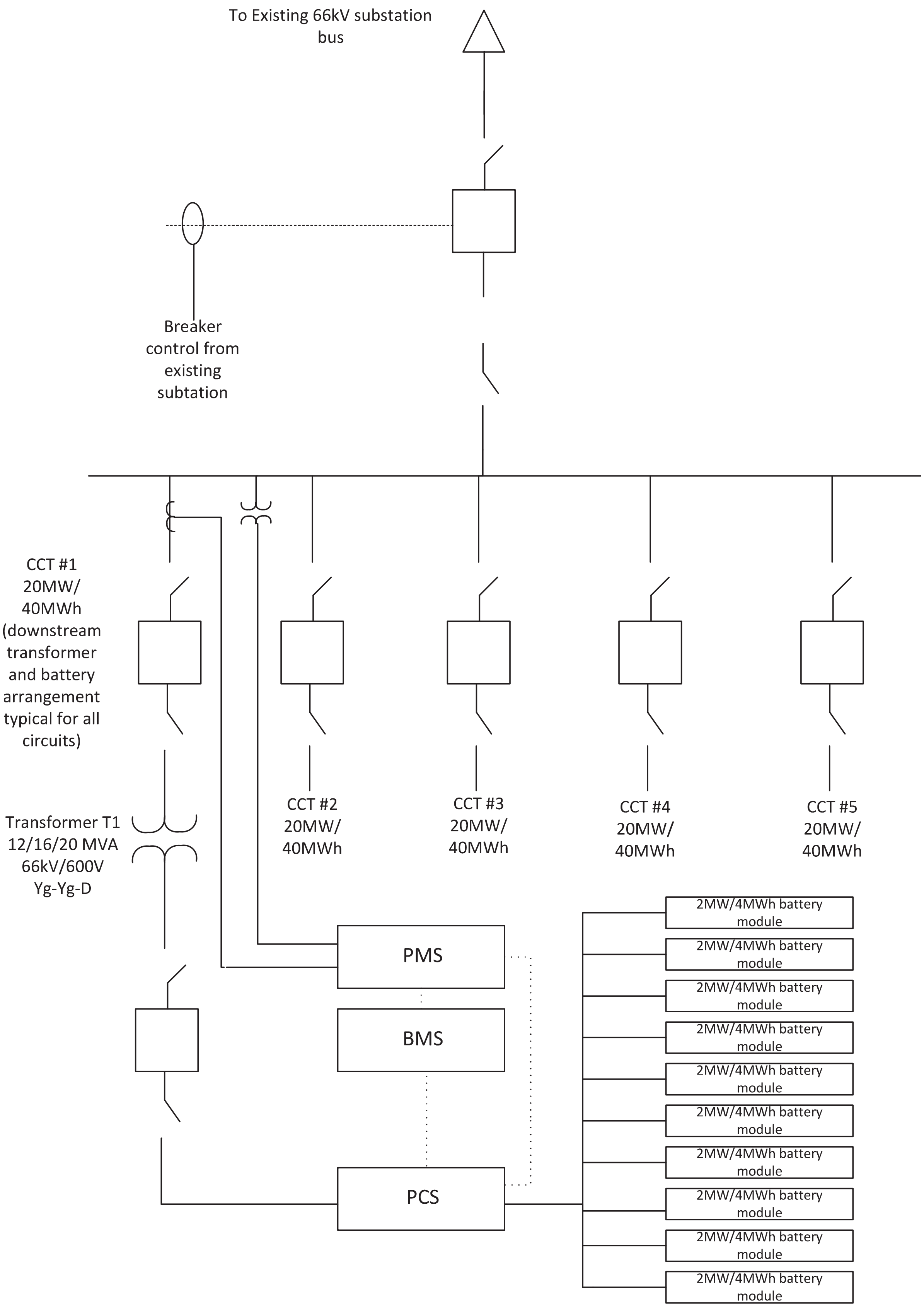
ACB
BCP #1
BCP #2
45ft Battery Container #1
45ft Battery Container #2
45ft Battery Container #3
45ft Battery Container #4
45ft Battery Container #5
45ft ESS-PCS Container #1
45ft ESS-PCS Container #2
45ft ESS-PCS Container #3

Appendix C

Interconnection SLD

NEW COLLIERS LTD.

100MW/200MWh Battery Storage Project
66kV Interconnection to Existing Substation
Preliminary Single Line Diagram
Rev. A – August 31, 2018



Appendix D

HICO ESS Product Literature

Hyosung Corporation

ESS

for Future Energy Solution

Power Systems PU
2018

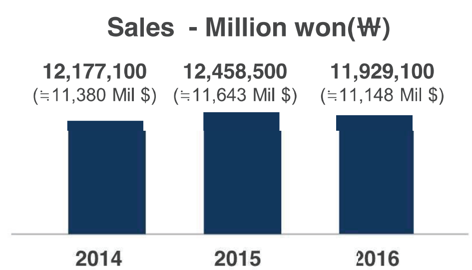
HYOSUNG

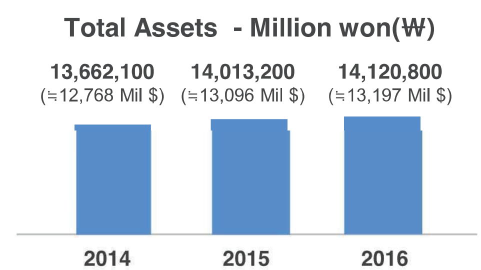
Contents

I. About Hyosung

HYOSUNG
Global Top Energy Solution Provider

$11B Revenue Company with 7 Performance Groups(PG*). Power and industrial systems performance group's major business area is T&D, motor and pump solutions.





HYOSUNG

Power & Industrial Systems PG
- GIS
- Transformer
- Smart Grid
- **Renewable Energy**
- STATCOM
- PV PCS
- Wind Turbine

Industrial Materials PG
- Tire Cord
- Steel Cord
- Bead Wire

Textile PG
- Spandex
- Nylon
- Polyester
- Dyeing

Chemical PG
- TPA
- Film

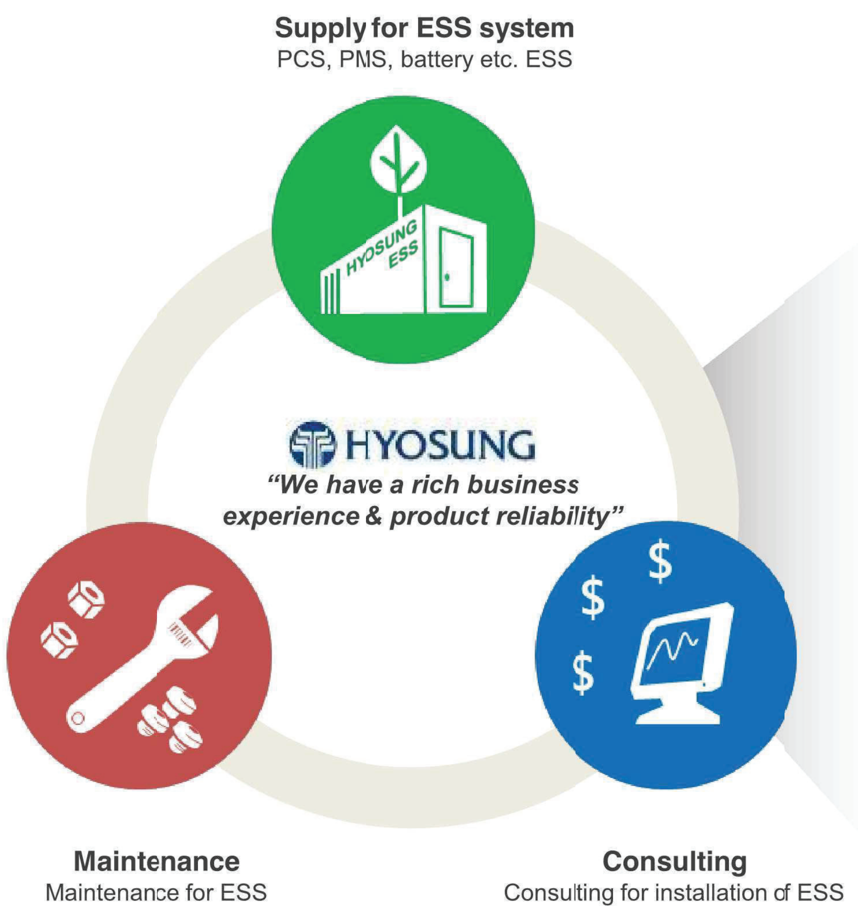
Information & Communication PG
- Banking Solution
- Storage Solution

Trading PG
- Steel
- Chemical
- Digital
- Machinery

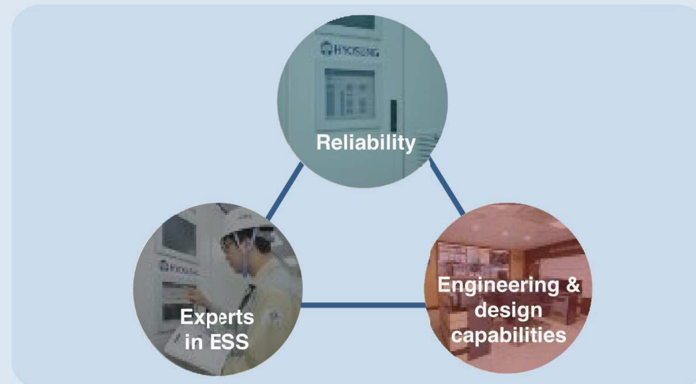
Construction & Engineering PG
- Apartment
- Civil Engineering
- Factory

* PG : Performance Group

Hyosung can provide energy storage solution with grid base engineering know-hows to maximize customers economic benefits with reliable product lines.



Strengths of HYOSUNG for ESS



Reliable products

- Hyosung experienced lots of ESS national project.
- Hyosung has a lot of experiences to provide ESS to customers (KHNP, KEPCO etc.) that require high reliability.

ESS experts and Maintenance

- Hyosung has been a lot of projects and has strong project pipeline, so problems encountered during the project implementation could to minimize.
- When a problem occurs, Hyosung's ESS experts will respond quickly to problems.

ESS engineering & design capabilities

- Through Korea's no.1 power equipment manufacturer experience, Hyosung holds a high understanding for the grid.
- Hyosung can suggest ESS specifications and operational plans for the customers.

II. The concept of ESS

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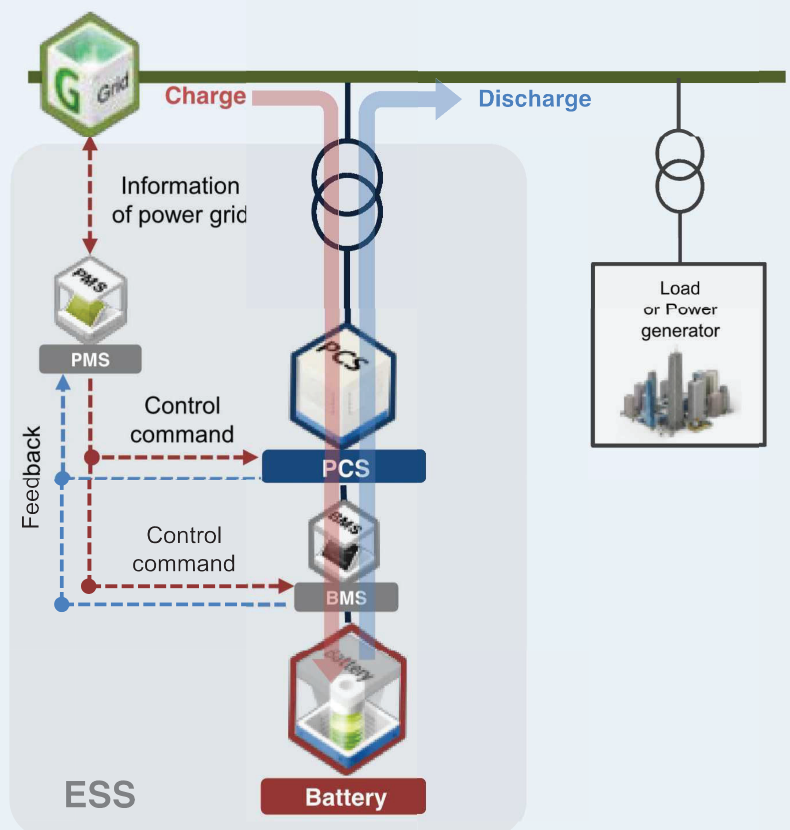
BESS(Battery Energy Storage System), so-called ESS, is a system used for storing electrical energy to secondary battery for timely use.

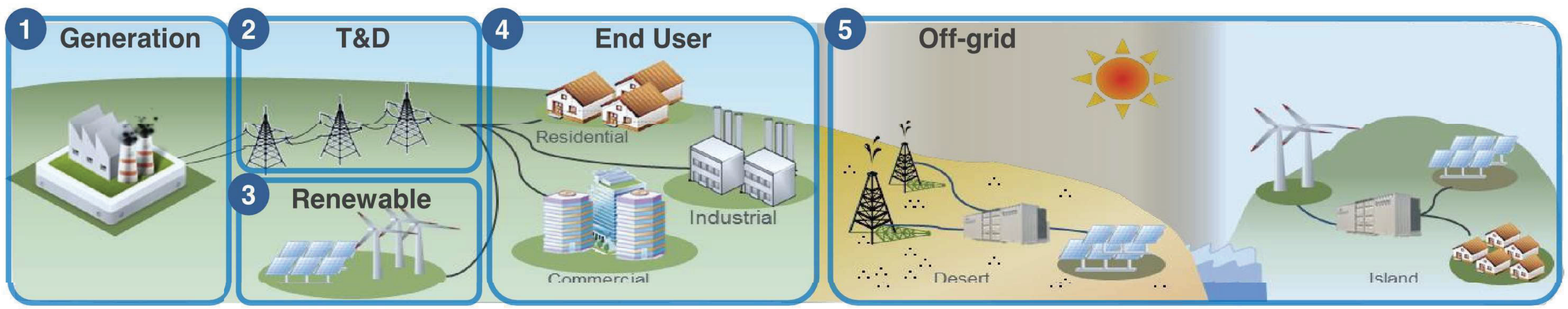
Concept



Summary

Principle	▪ Storing electrical energy to Secondary batteries (Li-ion, Lead-acid, NaS, etc)
Composition Role	▪ PMS: Control PCS, BMS ▪ PCS: Convert AC/DC, Power quality control ▪ BMS: Control and Monitoring batteries ▪ Battery: Store electrical energy
Life Expectancy	10~20 years
Efficiency	More than 85%
Benefits	▪ Reserving Power electricity ▪ Frequency Regulation ▪ Improving Power quality ▪ Supporting Renewables ▪ Supporting Users for efficient power usage ▪ Voltage control ▪ T&D investment Deferral
Construction Period	Less than 1 year

ESS is applicable to entire power system area from generation to end user. It has multiple benefits such as improving & stabilizing power quality, supporting renewables and off-grids.



1 Generation

- **Improving Generation efficiency**
  - Aiding generators by smoothing load fluctuation
  - Decentering peak load / Improving power quality
  - Supplying seconds-scale reserve
  - Providing spinning reserves

2 T&D

- **Ancillary services**
  - Defer additional investments by reduce load
  - Responding sharp drop of voltage in a grid
  - Stabilizing power grid with regulating frequency

3 Renewables

- **Controlling Renewable output**
  - Smoothing irregular output power
  - Profit obtained by the difference between REC's weighting*

*REC : Renewable Energy Certificate

4 End User

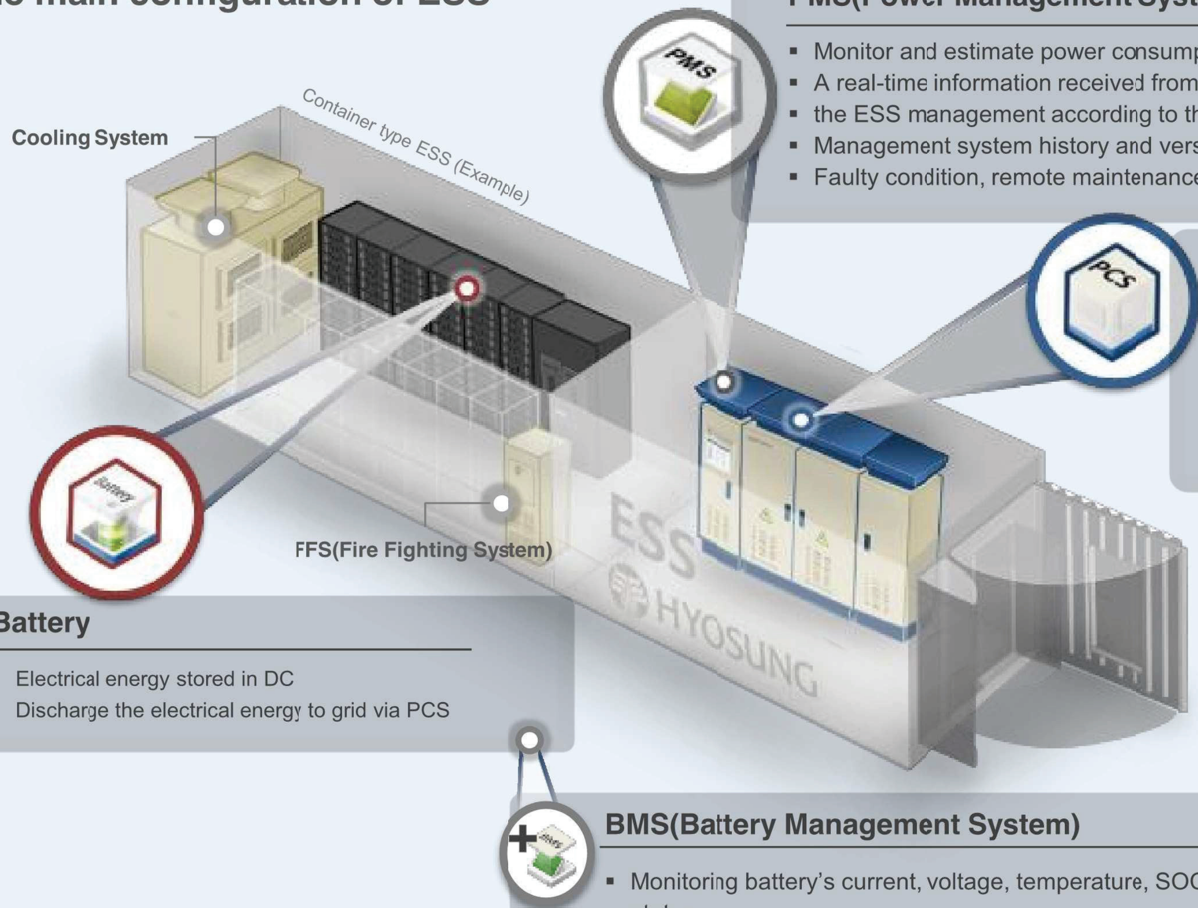
- **Supporting Effective Power usage**
  - Charge at off-peak, discharge at on-peak
  - Prevent blackout & voltage drop
  - Power usage management and UPS

5 Off-grid

- **Supply power to the grid insufficient area through renewable integration**
  - Store produced electricity through renewable energy in the areas of power does not reach such as island and desert

ESS is composed of PMS which control all the component of ESS, PCS which convert AC to DC and Batteries and BMS which control battery Modules and cells.

The main configuration of ESS



PMS(Power Management System)

- Monitor and estimate power consumption and active operation
- A real-time information received from PCS to monitor the ESS
- the ESS management according to the host controller command
- Management system history and version
- Faulty condition, remote maintenance for recovery available

PCS(Power Conditioning System)

- Invert DC power stored in batteries to AC power with voltage and frequency of commercial
- Convert AC power to DC and charged in batteries

Battery

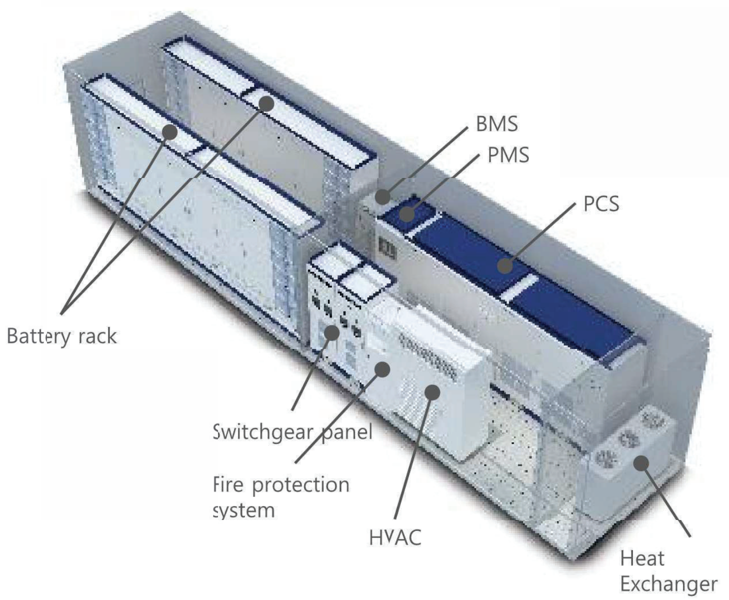
- Electrical energy stored in DC
- Discharge the electrical energy to grid via PCS

BMS(Battery Management System)

- Monitoring battery's current, voltage, temperature, SOC, devices status
- Exchange information and data to communicate with PCS

ESS could be installed with container type ESS or structure type ESS depends on capacity or customer's needs.

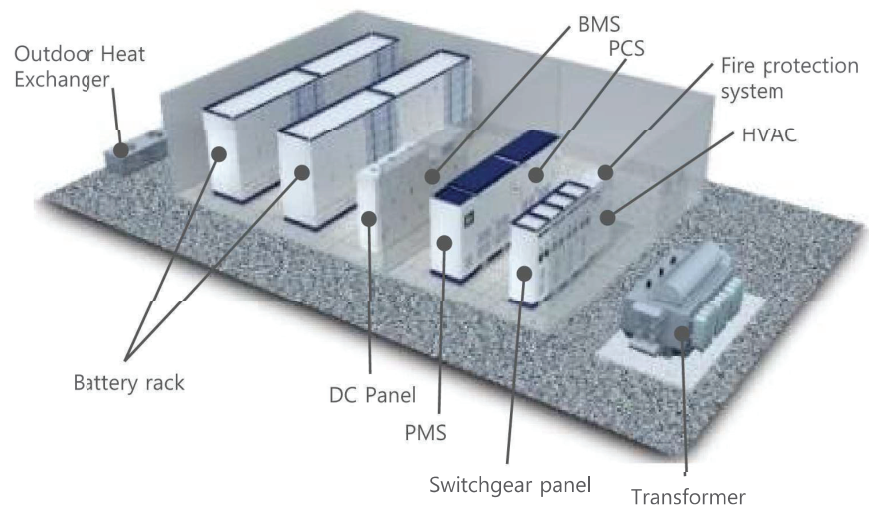
Container Type ESS



※ Up to 1MW/500kWh for standard 40ft. container

- Configured with PCS, Battery, HVAC, DC Link, monitoring module and fire protection system and may include transformer and switchgear panel if necessary
- Up to 1MW/500kWh (Standard 40ft. container)
- Transportable form production is also possible upon Customer's need
- Due to the nature of Battery, optimization design of air-cooling and fire safety equipment are critical design elements

Indoor Type ESS



- Most ESS more than 10MW of the U.S. is in the form of building structure include PCS, STATCOM and Battery
- Battery and PCS is required isolation or blocking for fire prevention
- STACOM can compensate active and reactive power with ESS

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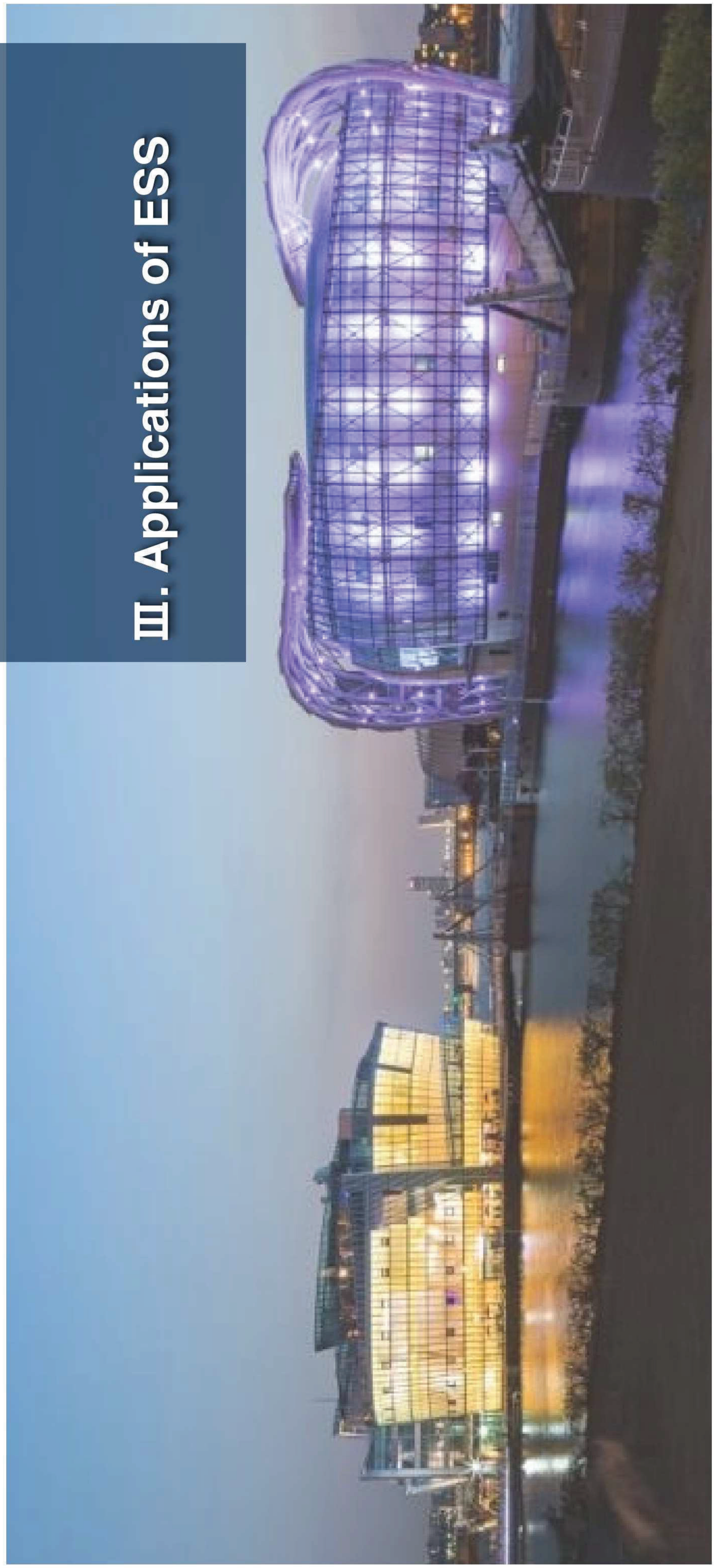
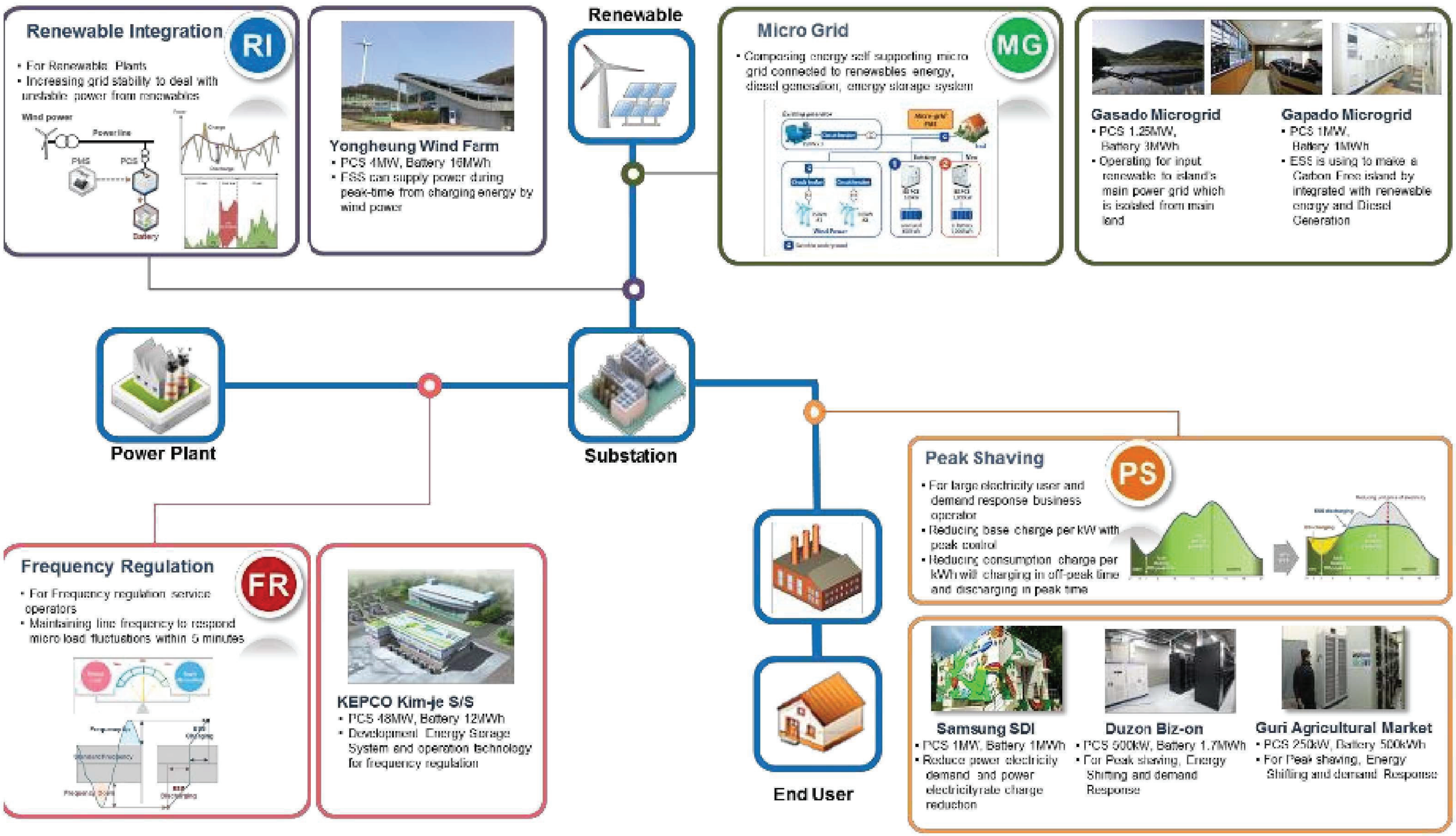
Ⅲ. Applications of ESS



▨ Major applications are Peak Shaving(PS), Frequency Regulation(FR), Renewable Integration(RI) and Micro-grid(MG) as shown the figure.



Major applications are Peak Shaving(PS), Frequency Regulation(FR), Renewable Integration(RI) and Micro-grid(MG) as shown the table.

	FR Frequency Regulation	PS Peak Shaving	RI Renewable Integration	MG Micro-grid
Purpose	▪ Providing spinning reserves ▪ Stabilizing power grid with regulating frequency ▪ Supplying reserve to grid	▪ Doing arbitrage with charging in off-peak and discharging in peak. ▪ Distracting load in peak time(Peak shifting)	▪ the difference between the REC ▪ Smoothing output of wind and photovoltaic generators ▪ Postponing investments to additional T&D infrastructure integrated renewables	▪ Smoothing output of wind and photovoltaic generators ▪ Postponing investments to additional T&D infrastructure integrated renewables ▪ Supply power to the grid insufficient area through renewables integration
Discharging Time	Less than 10~30 minutes	More than 2 hours	0.5~5 hours	0.5~5 hours
Benefits	▪ Saving fuel and overhaul cost of frequency regulation by conventional generation ▪ Stabilizing power grid with fast response performance ▪ Improving power quality	▪ Reducing risk of power shortage in peak time ▪ Postponing investments to additional power plant ▪ Doing arbitrage with electricity	▪ Maximizing revenue of selling power with timely discharging ▪ Stabilizing power grid ▪ Saving cost of grid operation with controlling renewables power output	▪ Maximizing revenue of selling power with timely discharging ▪ Stabilizing power grid ▪ Saving cost of grid operation with controlling renewables power output
Major user	Grid operator, Generation company	End-users	Renewables power plants	Renewables power plants
Case of installation	▪ 1MW ESS (PJM for ancillary service) ▪ 8MW ESS (NYISO for Frequency Regulation) ▪ 4MW ESS (KEPCO for supplying reserve and improving power quality in Chochun S/S)	▪ 1MW/1MWh Samsung SDI Ki-heung Plant, Gyeonggi Province ▪ 250kW/500kWh Guri Agricultural & Marine Products Wholesale Market, Gyeonggi Province	▪ KOSEP(Young-Heung WT) 4MW/16MWh ESS ▪ 800kW ESS (Haengwon, Jeju for integrating wind power plant)	▪ Jaeju Gapado island 1MW/1MWh ESS ▪ Gasado island 1.25MW/3MWh ESS ▪ Mozambique Off-grid(desert)

IV. Hyosung's ESS

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For convenience of customer value, Hyosung can provides all equipment and service for energy storage system.

PS FR HYOSUNG RI MG

Turn-key Solution

- Based on power electronics and energy management technology, Hyosung provides various equipment, system and service for energy storage system, including ES-PCS, power management system and turnkey solution.

PCS

- Hyosung manufactures and supplies 250kW, 500kW and 1MW PCS units for ESS.
- All of the PCS have isolated system operating functions. Based on high efficiency and high reliability, Hyosung's PCS can be applied various environment, including building, plants, substation and renewable energy.

PMS

- For maximize performance of energy storage system, Hyosung's power management system provides various operation algorithm and functions.
- By monitoring, controlling, and interoperating with other system. Power management system can improve power quality and cost-effectiveness of energy users.

Hyosung ES-PCS provides highly effective power conditioning system for all kinds of storage technology and we have PCS manufacturing & test facilities in Korea.

PCS(Power Conditioning System)

Hyosung PCS's main function

Bi-directional power control	▪ Controlling power inflow and outflow between battery and power grid
Power quality compensation	▪ Compensating voltage (reactive power) of power grid
Grid synchronization	▪ Providing phase angle by estimating system voltage phase
Protecting grid	▪ Protecting power grid based on IEEE Standard 1547
Communication interface	▪ Communicating with BMS and PMS for effective operation of ESS

PCS manufacturing and test facilities

- HYOSUNG perform the PCS production and inspection directly at Se-jong Plant(Korea).
- PCS factory and QC equipment factory

PCS manufacturing factory

PCS manufacturing line

QC equipment factory

Equipment of TEST

[AC Grid Simulator] [DC Supplier] [RLC Load simulator]

HYOSUNG's ES-PCS(2/2)

Technical Data		HS-E110G	HS-E250G	HS-E500GL	HS-E1000G	HS-E2000GL
Input Side(DC)		550~850V	550~850V	550~850V	750~1,050V	750~1,050V
	Max. Input Current	218A	500A	1,000A	1,333A	2,667A
Output Side(AC)	Rated Power	110kW	250kW	500kW	1,000kW	2,000kW
	Output Voltage	3Ø, 380V	3Ø, 380V	3Ø, 340V	3Ø, 440V	3Ø, 440V
	Output Current	167A	380A	849A	1,312A	2,625A
	Grid Frequency	50/60Hz	50/60Hz	60Hz	60Hz	60Hz
	THD	<5%	<5%	<5%	<5%	<5%
	Power Factor	>0.99	>0.99	>0.99	>0.99	>0.99
Efficiency	Max. Efficiency	>97%	>97%	>97%	>97%	>97%
Environ-mental	Grid Tied Transformer	O	O	X	X	X
	Cooling	Forced Air	Forced Air	Forced Air	Forced Air	Forced Air
	Ambient Temperature	-20~50°C	-20~50°C	-20~50°C	-20~40°C	-20~40°C
	Relative humidity	<95%RH	<95%RH	<95%RH	<95%RH	<95%RH
Mechanical Spec.	Protection Class	IP20	IP20	IP20	IP20	IP20
	Dimensions (W/D/H)[mm]	1200*850*2120	2400*850*2120	2200*990*2200	4000*750*2220	5500*1100*2200
	Weight	1,070kg	2,400kg	1,930kg	2,930kg	5,000kg
Communication	Comm. Port	CAN2.0, RS422	CAN2.0, RS422	CAN2.0, RS422	CAN2.0, RS422	CAN2.0, RS422
Image						

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ERROR: ioerror
OFFENDING COMMAND: image

STACK:

-mark-
-savelevel-
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Attachment 8

Island Pond Hydroelectric Development Report

Island Pond Hydroelectric Development

November 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Summary

The study includes the consideration of the construction of a new 36 MW hydroelectric generating station at Island Pond to be located on the North Salmon River, within the watershed of the Bay d'Espoir Development, between the existing Meelpaeg Reservoir and the Upper Salmon Development. The total capital cost of $405.2 million (approximately $11.2 million per megawatt).

The principal parameters for this development are as follows:

- Time to project in-service 48 months
- Installed Capacity 36 MW
- Minimum Capacity 7.2 MW
- Number of Units 1
- Estimated Unit Efficiency 94%
- Average Annual Energy 186 GWh

The Island Pond Hydroelectric Generating Station shall be connected to the Island transmission system via two, nine kilometre long sections of 230 kV transmission line which are required along the existing TL 263 corridor to interconnect the facility at Upper Salmon and Granite Canal Tap and a new terminal station with a 230 kV ring bus configuration at Island Pond.

Operations and Maintenance ("O&M") is estimated to have a fixed cost of $3.3 million and a variable cost of $1.1 million (approximately $5.70 per MWh) annually.

Table of Contents

1 Project Description

This alternative consists of the construction of a new 36 MW hydroelectric generating station at Island Pond. The proposed facility would be located on the North Salmon River, within the watershed of the Bay d'Espoir Development, between the existing Meelpaeg Reservoir and the Upper Salmon Development. The new facility would utilize the available head of approximately 25 metres between the Meelpaeg Reservoir and Crooked Lake. The development is comprised of the following key components:

- Construction of a 3,000 metre long diversion canal between Meelpaeg Reservoir and Island Pond;
- Completion of 3,400 metres of channel improvements in Meelpaeg Reservoir and Island Pond;
- Construction of a new concrete gravity dam;
- Construction of a new close-couple powerhouse and intake structure;
- Construction of a 750 metre forebay canal to pass water to the dam, intake, and powerhouse;
- Construction of a 550 metre tailrace to discharge water into Crooked Lake; and
- Construction of a transmission line and associated terminal station to complete interconnection with the existing System.

A spillway is not required for the development as floodwaters from the Island Pond watershed would be diverted back into the Meelpaeg Reservoir, via the Diversion Canal, and stored in the combined Meelpaeg-Island Pond Reservoir to ultimately be routed through the System as regulated discharge.

The facility would be equipped with a single, vertical-axis Kaplan turbine with a rated output of 36 MW. The Kaplan turbine was selected as it will enable operation during low flow periods.

In order to complete the interconnection with the existing system, two, nine kilometre long sections of 230 kV transmission line are required along the existing TL 263 corridor to interconnect the facility at Upper Salmon and Granite Canal Tap. In order to facilitate this interconnection, a new terminal station with a 230 kV ring bus configuration is required at Island Pond. An outline of the transmission requirements can be found in Section 3.

It should be noted that no upgrades have been considered to upgrade the storage capacity of the existing reservoir system.

2 Generation Characteristics

The principal parameters for this development are as follows:

- Installed Capacity 36 MW
- Minimum Capacity 7.2 MW
- Number of Units 1
- Estimated Unit Efficiency 94%
- Average Annual Energy 186 GWh

3 Transmission Requirements

The Island Pond site sits between the Upper Salmon and Granite Canal generation sites in the Bay d'Espoir watershed. The 230 kV transmission line, TL 263 (Upper Salmon to Granite Canal Tap), was constructed such that the line could be opened at two strategically points and two, nine kilometre long segments completed to tie the Island Pond site to the System.

With the 230 kV transmission system extended west from Granite Canal, as a result of the completion of the 230 kV transmission line TL 269 (Granite Canal Tap to Bottom Brook), the Island Pond Terminal Station must be configured as a 230 kV ring bus. Given the connection at the 230 kV level, the terminal station will require redundant high speed protection (Protection Group A and Protection Group B) with each protection groups supplied from a separate battery bank (Battery Bank A and Battery Bank B). In addition, the station will require two independent sources of station service.

4 Environmental Considerations

Hydroelectric developments of this nature will be subject to the Provincial Environmental Protection Act, and the Environmental Assessment Regulations. The overall timeline for the regulatory approval process could be impacted should an Environmental Preview Report or an Environmental Impact Statement be required. The project could also be subject to the Federal Environmental Assessment Process. The Federal government in accordance with the Canadian Environmental Assessment Act usually reviews undertakings that are subject to the Provincial Environmental Assessment Process. Where possible, the Provincial and Federal Environmental Assessment Process are harmonized in an effective and timely manner.

The most substantial environmental impact is anticipated to be on the fish habitat, affected during both the construction and operation of the plant. In order to mitigate these impacts, the compensation of fish habitat destroyed or altered by the project will form an integral part of the project's scope. Preliminary assessment has concluded that the project may affect 583 units of habitat. Additional environmental/biological studies related to wildlife and rare plants may also be required.

Preliminary geotechnical assessments of the region have also identified the potential for acid generating rock within the forebay, dam, powerhouse, and tailrace areas. Mitigation measures will require that all rock, exceeding the limits for the potential for acid drainage, be properly disposed of. A bedrock sampling and testing program will need to be completed prior to, and during, construction when more thorough sampling can be completed at rock excavation sites.

Similar to the hydroelectric component, transmission line construction would also be subject to Environmental Assessment. While detailed design has yet to be completed, there are no immediate concerns with respect to the proposed line routing. It is believed that any environmental issues would be typical of any transmission line construction project and could be easily mitigated.

During construction, the control of sedimentation from excavation activities warrants special attention. Controls such as silt fences, rip rap, turbidity curtains, properly constructed settlement basins, containment of run-off from spoil areas and the relocation of fish during de-watering will need to be implemented. The handling and storage of fuels and other hazardous materials in an environmentally safe manner is also included in the cost.

One of the possible outcomes of the regulatory approval process will be the requirement to develop a detailed Environmental Protection Plan for the Project. An Environmental Protection Plan generally outlines the Owner's policy with respect to environmental protection, the Owner's responsibility, the Contractor's responsibility, compliance monitoring requirements, effects monitoring requirements, and contractor/sub-contractor education, etc.

5 Cost

5.1 Methodology

The cost estimate, for the construction of the Island Pond Hydroelectric Generating Station was derived from the report “Studies for Island Pond Hydroelectric Project,” SNC Lavalin, 2006. This estimate was later updated by SNC Lavalin in 2012.

As no additional engineering has been completed for this option, the current estimate was derived by first escalating the 2012 costs to present-day dollars. This was achieved through the application of historical construction price escalation for electric utility construction projects as measured by Statistics Canada.

Following the completion of the cost escalation exercise, pricing for major components of the project including the penstock, powerhouse, generating unit, construction camps, and construction support services were compared to current costs generated for projects of similar size and complexity. Where required, the costs were factored proportionately.

5.2 Capital Cost

A class 5 estimate was prepared in accordance with the methodology outlined in Section 5.1. This estimate is considered to be adequate for concept screening purposes and carries an expected accuracy range of -20% to +50%.

A summary of the estimate can be seen in Table 1.

Table 1: Project Budget Estimate ($000s)

Project Cost	Year 1	Year 2	Year 3	Year 4	Total
Material Supply	533.8	1,337.8	1,731.7	1,696.8	5,300.0
Labour	2,846.8	7,134.7	9,235.8	9,049.4	28,266.7
Consultant	3,558.5	8,918.4	11,544.8	11,311.7	35,333.4
Contract Work	0.0	61,395.8	92,358.2	90,493.9	244,247.9
Other Direct Costs	177.9	445.9	577.2	565.6	1,766.7
Interest	108.4	1,591.9	6,546.0	19,056.1	27,302.4
Contingency	0.0	0.0	0.0	62,983.0	62,983.0
Total	**7,225.5**	**80,824.5**	**121,993.7**	**195,156.5**	**405,200.2**

This equates to approximately $11.2 million per megawatt.

5.3 Operation and Maintenance Costs

Annual O&M costs for hydroelectric generation plants are typically classified as fixed or variable. Fixed O&M costs relate to those costs incurred during the upkeep and maintenance of the various assets. They typically do not vary significantly with generation and include items such as staffing, plant related general and administrative expenses, and maintenance of structures and grounds.

Variable O&M expenses are production-related costs which vary with the amount of electricity generation. These costs include maintenance of mechanical components such as turbine bearings and runners.

Rule of thumb estimates for the anticipated annual maintenance costs were completed. These estimates were derived from parameters, established through a third party consultant's review of their database for similar works. The parameters utilized for fixed and variable maintenance estimates are as follows:

- Variable O&M: $5.70 per MWh
- Fixed O&M: 1% to 2% of direct project cost per year

This equates to an estimated annual variable O&M cost of $1,060,200.00 and a fixed O&M cost of $3,292,171.79.

6 Schedule

The construction methodology for this project is typical for heavy civil construction projects, involving various types of earthworks, concrete structures, and major dewatering efforts. The schedule assumes an overall project duration of 48 months. A summary of the schedule is as follows:

6.1 Year One

- Initiate Environmental and Regulatory approval process;
- Complete additional field testing; and
- Engineering/procurement of major equipment.

6.2 Year Two

- Complete environmental and regulatory approvals;
- Construct access roads;
- Construct camp facilities;
- Install site services infrastructure;
- Construct forebay canal;
- Excavate for powerhouse;
- Commence concrete placement; and

- Enclose of powerhouse.

6.3 Year Three

- Deliver and install powerhouse mechanical and electrical components;
- Commence construction of diversion canal;
- Commence channel improvements in Meelpaeg reservoir and Island Pond;
- Commence fish habitat mitigation; and
- Commence construction of concrete gravity dam.

6.4 Year Four

- Complete diversion canal;
- Complete gravity dam and related facilities;
- Complete tailrace and fish habitat compensation works;
- Construct switchyard and transmission line;
- Complete powerhouse mechanical and electrical; and
- Complete final testing and commissioning.

The following works/activities are considered to be on the critical path of the project:

- Environmental and regulatory approvals;
- Detailed design and tending of the water-to-wire (“W2W”) package;
- Design, manufacturing, and delivery of the W2W equipment;
- Installation of construction camp;
- Completion of powerhouse enclosure;
- Completion of fish habitat mitigation; and
- W2W equipment installation and commissioning.

7 Feasibility

Based on the preliminary information there are no anticipated restrictions which would prevent the development of the project. No impact to the existing system is anticipated during construction and the identified environmental concerns can be addressed through the design and implementation of mitigation measures.

There are, however, some operational restrictions stemming from the low head at Island Pond (22 metres), when compared with the 190 metre of head at Bay d'Espoir. Consequently, the Island Pond unit should be operated as an energy producer, rather than a peaking unit.

Attachment 9

Portland Creek Hydroelectric Development Report

Portland Creek Hydroelectric Development

August 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Summary

The study includes the consideration of the development of a 23 MW hydroelectric generating facility at Portland Creek at a total capital cost of $261.8 million (approximately $11.4 million per megawatt).

The principal parameters for this development are as follows:

- Time to project in-service 48 months
- Installed Capacity 23 MW
- Minimum Capacity 2.3 MW
- Number of Units 2
- Estimated Unit Efficiency 88.2%
- Average Annual Energy 142 GWh

The Portland Creek Generating Station shall be connected to the Island transmission system via a 66 kV transmission line approximately 25.5 kilometres to the existing Peter’s Barren Terminal Station.

Operations and Maintenance (“O&M”) is estimated to have a fixed cost of $2.7 million and a variable cost of $0.8 million (approximately $5.70 per MWh) annually.

Table of Contents

1 Project Description

This alternative consists of the construction of a 23 MW hydroelectric generating station on Main Port Brook, a tributary of Portland Creek. Generally speaking, the proposed facility would be in Western Newfoundland and Labrador, near Daniel's Harbour on the west side of the Great Northern Peninsula.

The proposed development would utilize the approximately 395 metre head, available between the Head Pond and the outlet of Main Port Brook, and would be comprised of the following key components:

- Construction of a 320 metre long diversion canal to transfer flows from the diversion pond into the main storage reservoir;
- Construction of a 110 metre long, concrete gravity dam and overflow spillway with a crest length of 70 metres;
- Construction of a 45 metre long concrete gravity storage dam, including a flow regulating structure and trash rack;
- Construction of a 143 metre long concrete gravity headpond dam, including a power intake structure fitted with a trash rack and overflow spillway;
- Construction of a 1.5 metre diameter penstock, measuring 2,900 metres in length;
- Construction of a powerhouse;
- Construction of a 66 kV switchyard, adjacent to the powerhouse; and
- Construction of a transmission line, connecting the switchyard to the existing system.

The facility would be equipped with two Pelton turbine generating units, each with a rated output of 11.5 MW.

In order to complete the interconnection with the existing system, a 25.5 kilometre long, 66 kV transmission line is required to the existing Peter's Barren Terminal Station ("PBTS"). An outline of the transmission requirements can be found in Section 3.

2 Generation Characteristics

The principal parameters for this development are as follows:

- Installed Capacity 23 MW
- Minimum Capacity 2.3 MW
- Number of Units 2
- Estimated Unit Efficiency 88.2%
- Average Annual Energy 142 GWh

In the absence of a system study to evaluate the role of Portland Creek, the following pattern of daily operation was assumed for the feasibility study:

- 4 hours at 6.6 m^3/s, resulting in 23 MW of generation; and
- 20 hours at 1.08 m^3/s, giving 3.9 MW.

Energy benefits were projected by means of a regulation model that simulated plant operation, on a daily basis, for the available period of records (1984 to 2005). The regulation model accounts for daily inflows, changes in reservoir storage, power flows, spillway flows, and computed daily energy production. Power flows were determined using a rule curve, developed to ensure that minimum acceptable environmental flows were reliably provided. Minimum acceptable environmental flows were set at 3.5 m^3/s, from the period of May 1 to September 30, and 2.0 m^3/s from October 1 to April 30.

3 Transmission Requirements

The Portland Creek Generating Station would connect to the Island transmission system via a 66 kV transmission line approximately 25.5 kilometres to the existing PBTS. The existing 66 kV bus at PBTS would be extended to accommodate the 66 kV Portland Creek transmission line.

Given the proposed two unit configuration, two independent sources of station service at the plant are provided from the terminals of each generator. Consequently, it is proposed to utilize 66 kV breakers on each generator step-up transformer for synchronizing the unit to the grid and for unit shut down. With both units out of service, it is proposed to supply station service from a local black start diesel.

4 Environmental Considerations

Hydroelectric developments of this nature will be subject to the Provincial Environmental Protection Act, and the Environmental Assessment Regulations. The overall timeline for the regulatory approval process could be impacted should an Environmental Preview Report or an Environmental Impact Statement be required. The project could also be subject to the Federal Environmental Assessment Process. The Federal government in accordance with the Canadian Environmental Assessment Act usually reviews undertakings that are subject to the Provincial Environmental Assessment Process. Where possible the Provincial and Federal Environmental Assessment Process are harmonized in an effective and timely manner.

The most substantial environmental impact is anticipated to be on the fish habitat, affected during both the construction and operation of the plant. In order to mitigate these impacts, the compensation of fish habitat destroyed or altered by the project will form an integral part of the project's scope. An assessment to quantify the potential extent of fish habitat that may be impacted has not yet been undertaken. Additional environmental/biological studies related to wildlife and rare plants may also be required.

Similar to the hydroelectric component, transmission line construction would also be subject to Environmental Assessment. While detailed design has yet to be completed, there are no immediate concerns with respect to the proposed line routing. It is believed that any environmental issues would be typical of any transmission line construction project and could be easily mitigated.

During construction, the control of sedimentation from excavation activities warrants special attention. Controls such as silt fences, rip rap, turbidity curtains, properly constructed settlement basins, containment of run-off from spoil areas and the relocation of fish during dewatering will need to be implemented. The handling and storage of fuels and other hazardous materials in an environmentally safe manner is also included in the cost.

One of the possible outcomes of the regulatory approval process will be the requirement to develop a detailed Environmental Protection Plan for the Project. An Environmental Protection Plan generally outlines the Owner's policy with respect to environmental protection, the Owner's responsibility, the Contractor's responsibility, compliance monitoring requirements, effects monitoring requirements, and contractor/sub-contractor education, etc.

5 Cost

5.1 Methodology

The cost estimate, for the construction of the Portland Creek Hydroelectric Generating Station was derived from the "Feasibility Study for Portland Creek Hydroelectric Project," SNC Lavalin, 2007. This estimate was later updated by SNC Lavalin in 2012.

As no additional engineering has been completed for this option, the current estimate was derived by first escalating the 2012 costs to present day dollars. This was achieved through the application of historical construction price escalation for electric utility construction projects as measured by Statistics Canada.

Following the completion of the cost escalation exercise, pricing for major components of the project including the penstock, powerhouse, generating unit, construction camps, and construction support services were compared to current costs, generated for projects of similar size and complexity. Where required, the costs were factored proportionately.

5.2 Capital Cost

A class 5 estimate was prepared in accordance with the methodology outlined in Section 5.1. This estimate is considered to be adequate for concept screening purposes and carries an expected accuracy range of -20% to +50%.

A summary of the estimate can be seen in Table 1.

Table 1: Project Budget Estimate ($000s)

Project Cost	Year 1	Year 2	Year 3	Year 4	Total
Material Supply	392.9	720.4	2,132.5	0.0	3,245.8
Labour	2,095.3	3,841.9	11,373.6	33.9	17,344.7
Consultant	2,619.1	4,802.4	14,217.0	35.7	21,674.2
Contract Work	2,329.9	38,419.2	113,736.0	285.3	154,770.3
Other Direct Costs	131.0	240.1	710.8	1.8	1,083.7
Interest	110.8	1,259.4	5,539.5	17,161.7	24,071.4
Contingency	0.0	0.0	0.0	39,623.7	39,623.7
Total	**7,678.9**	**49,283.4**	**147,709.4**	**57,142.0**	**261,813.8**

This equates to approximately $11.4 million per megawatt.

5.3 Operation & Maintenance Costs

Annual O&M costs for hydroelectric generation plants are typically classified as fixed or variable. Fixed O&M costs relate to those costs incurred during the upkeep and maintenance of the various assets. They typically do not vary significantly with generation and include items such as staffing, plant related general and administrative expenses, and maintenance of structures and grounds.

Variable O&M expenses are production-related costs which vary with the amount of electricity generation. These costs include maintenance of mechanical components such as turbine bearings and runners.

Rule of thumb estimates for the anticipated annual maintenance costs were completed. These estimates were derived from parameters, established through a third party consultant’s review of their database for similar works. The parameters utilized for fixed and variable maintenance estimates are as follows:

- Variable O&M: $5.70 per MWh

- Fixed O&M: 1% to 2% of direct project cost per year

This equates to an estimated annual variable O&M cost of $809,400.00 and a fixed O&M cost of $2,703,345.46.

6 Schedule

The construction methodology for this project is typical for heavy civil construction projects, involving various types of earthworks, concrete structures, etc. The schedule assumes an overall project duration of 48 months. A summary of the schedule is as follows:

6.1 Year One

- Environmental and Regulatory approval process initiated; and
- Complete additional field testing.

6.2 Year Two

- Engineering/procurement of major equipment.
- Completion of environmental and regulatory approvals;
- Construction of access roads;
- Excavate and backfill the powerhouse/switchyard area;
- Construct fish habitat compensation area;
- Construction of camp facilities; and
- Installation of site services infrastructure.

6.3 Year Three

- Construct the powerhouse;
- Construct the penstock;
- Construct the switchyard;
- Construct the headpond dam, storage dam and diversion dam;

- Construct the diversion canal;
- Complete reservoir clearing; and
- Construct the transmission line.

6.4 Year Four

- Completion of powerhouse mechanical and electrical; and
- Final testing and commissioning.

The following works/activities are considered to be on the critical path of the project:

- Environmental and regulatory approvals;
- Detailed design and tending of the water-to-wire ("W2W") package;
- Design, manufacturing and delivery of the W2W equipment;
- Construction of access roads;
- Installation of construction camp;
- Completion of fish habitat mitigation; and
- W2W equipment installation and commissioning.

7 Feasibility

Based on the preliminary information there are no anticipated restrictions which would prevent the development of the project. No impact to the existing system is anticipated during construction and any identified environmental concerns can be addressed through the design and implementation of mitigation measures.

Attachment 10

Round Pond Hydroelectric Development Report

Round Pond Hydroelectric Development

August 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Summary

The study includes the consideration of the development of an 18 MW hydroelectric generating facility at Round Pond at a total capital cost of $247.9 million (approximately $13.8 million per megawatt).

The principal parameters for this development are as follows:

• Time to project in-service	48 months
• Installed Capacity	18 MW
• Minimum Capacity	3.6 MW
• Number of Units	1
• Estimated Unit Efficiency	93%
• Average Annual Energy	139 GWh

The Round Pond Generating Station will be connected to the Island transmission system via a 69 kV transmission line, measuring approximately 44 km in length, to the existing Bay d'Espoir Terminal Station No. 2.

Operations and Maintenance ("O&M") is estimated to have a fixed cost of $1.3 M and a variable cost of $0.8 M (approximately $5.70/MWh) annually.

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1 Project Description

This alternative consists of the construction of a new, 18 MW hydroelectric generating station approximately 25 kilometres north of Bay d'Espoir, between the Bay d'Espoir and Upper Salmon developments. The Round Pond development is wholly contained within the Long Pond watershed.

The proposed development would utilize the natural head, available between the Godaleich Pond (Tailrace of Upper Salmon Development) and Long Pond Reservoir, and utilize the regulated outflow from the existing Upper Salmon Generating Station in conjunction with the natural drainage from Round Pond basin. The gross natural head is estimated to be 12.0 metres.

The present water elevation of Round Pond is 186.0 m and the normal water level of Long Pond is 180.75 metres. The Round Pond water level will be raised to a full supply level of 192.0 metres and low supply level of 189.0 metres. This will result in an additional flooded area of 800 hectares.

The key components of this project include:

- Construction of a 1,000 metre long main dam, including a gated spillway;
- Construction of three saddle dams, including to smaller structures (2.0 metres high) on the east side of the power canal and a 1,000 metres long structure, measuring 7.5 metres high, located approximately 2 kilometres north of the plant;
- Construction of a 250 metre long power canal, with an uncontrolled intake;
- Construction of a 25 metre long tailrace;
- Construction of a powerhouse;
- Construction of a 66 kV switchyard, adjacent to the powerhouse; and
- Construction of a transmission line, connecting the switchyard to the existing System.

The facility would be equipped with a single, bulb/pit type generating unit, with a rated output of 18 MW.

In order to complete the interconnection with the existing System, a 44 kilometre long, 69 kV transmission line is required to connect to the existing Bay d'Espoir Terminal Station No. 2. An outline of the transmission requirements can be found in Section 3.

2 Generation Characteristics

The principal parameters for this development are as follows:

- Installed Capacity 18 MW
- Minimum Capacity 3.6 MW
- Number of Units 1
- Estimated Unit Efficiency 93%
- Average Annual Energy 139 GWh

The Round Pond Development will be a Run-of-River operation, utilizing regulated flow from the Upper Salmon Development and local Round Pond drainage.

3 Transmission Requirements

The Round Pond Generating Station will be connected to the System via a 69 kV transmission line, measuring approximately 44 kilometre in length, to the existing Bay d'Espoir Terminal Station No. 2. Existing transformers T10 and T12, at Bay d'Espoir, will be replaced and the bus extended to accommodate the new 69 kV transmission line. Further assessment is required to determine whether or not the new line will be equipped with optical ground wire.

4 Environmental Considerations

Hydroelectric developments of this nature will be subject to the Provincial Environmental Protection Act, and the Environmental Assessment Regulations. The overall timeline for the regulatory approval process could be impacted should an Environmental Preview Report or an

Environmental Impact Statement be required. The project could also be subject to the Federal Environmental Assessment Process. The Federal government in accordance with the Canadian Environmental Assessment Act usually reviews undertakings that are subject to the Provincial Environmental Assessment Process. Where possible the Provincial and Federal Environmental Assessment Process are harmonized in an effective and timely manner.

The most substantial environmental impact is anticipated to be on the fish habitat, affected during both the construction and operation of the plant. In particular, fish movement from the Long Pond Reservoir to spawning habitat in the West Salmon River. In order to mitigate these impacts, the construction of fish passage facilities will form an integral part of the project's scope. Additional environmental/biological studies related to wildlife and rare plants may also be required.

Similar to the hydroelectric component, transmission line construction would also be subject to Environmental Assessment. While detailed design has yet to be completed, there are no immediate concerns with respect to the proposed line routing. It is believed that any environmental issues would be typical of any transmission line construction project and could be easily mitigated.

During construction, the control of sedimentation from excavation activities warrants special attention. Controls such as silt fences, rip rap, turbidity curtains, properly constructed settlement basins, containment of run-off from spoil areas and the relocation of fish during de-watering will need to be implemented. The handling and storage of fuels and other hazardous materials in an environmentally safe manner is also included in the cost.

One of the possible outcomes of the regulatory approval process will be the requirement to develop a detailed Environmental Protection Plan for the Project. An Environmental Protection Plan generally outlines the Owner's policy with respect to environmental protection, the

Owner's responsibility, the Contractor's responsibility, compliance monitoring requirements, effects monitoring requirements, and contractor/sub-contractor education, etc.

5 Cost

5.1 Methodology

The original cost estimate, for the construction of the Round Pond Hydroelectric Generating Station, was originally prepared for the "Round Pond Feasibility Study," Shawinigan Newfoundland Limited, 1988.

As no additional engineering has been completed for this option, the current estimate was derived by first escalating the costs to present day dollars. This was achieved through the application of historical construction price escalation for electric utility construction projects as measured by Statistics Canada.

Following the completion of the cost escalation exercise, pricing for major components of the project including the penstock, powerhouse, generating unit, construction camps and construction support services were compared to current costs, generated for projects of similar size and complexity. Where required, the costs were factored proportionately.

5.2 Capital Cost

A class 5 estimate was prepared in accordance with the methodology outlined in Section 5.1. This estimate is considered to be adequate for concept screening purposes and carries an expected accuracy range of -20% to +50%.

A summary of the estimate can be seen in Table 1.

Table 1: Project Budget Estimate ($000s)

Project Cost	Year 1	Year 2	Year 3	Year 4	Total
Material Supply	527.2	1,453.8	1,125.8	8.1	3,115.0
Labour	2,811.7	7,753.8	6,004.3	43.3	16,613.2
Consultant	3,514.6	9,692.3	7,505.4	54.2	20,766.5
Contract Work	7,201.0	77,538.1	60,043.4	433.3	145,215.8
Other Direct Costs	175.7	484.6	375.3	2.7	1,038.3
Interest	152.9	2,526.0	7,592.9	13,570.6	23,842.4
Contingency	0.0	0.0	0.0	37,349.7	37,349.7
Total	**14,383.2**	**99,448.6**	**82,647.2**	**51,461.9**	**247,940.8**

This equates to approximately $13.8 million per megawatt.

5.3 Operation & Maintenance Costs

Annual O&M costs for hydroelectric generation plants are typically classified as fixed or variable. Fixed O&M costs relate to those costs incurred during the upkeep and maintenance of the various assets. They typically do not vary significantly with generation and include items such as staffing, plant related general and administrative expenses, and maintenance of structures and grounds.

Variable O&M expenses are production-related costs which vary with the amount of electricity generation. These costs include maintenance of mechanical components such as turbine bearings and runners.

Rule of thumb estimates for the anticipated annual maintenance costs were completed. These estimates were derived from parameters, established through a third party consultant's review of their database for similar works. The parameters utilized for fixed and variable maintenance estimates are as follows:

- Variable O&M:$5.70 per MWh
- Fixed O&M: 1% to 2% of direct project cost per year

This equates to an estimated annual variable O&M cost of $792,300.00 and a fixed O&M cost of $1,302,511.84.

6 Schedule

The construction methodology for this project is typical for heavy civil construction projects, involving various types of earthworks, concrete structures, etc. The schedule assumes an overall project duration of 48 months. A summary of the schedule is as follows:

6.1 Year One

- Environmental and Regulatory approval process initiated;
- Complete additional field testing;

6.2 Year Two

- Engineering/procurement of major equipment;
- Completion of environmental and regulatory approvals;
- Construction of access roads;
- Construction of camp facilities;
- Complete reservoir clearing;
- Construct central/east causeway dams;
- Construction of spillway;
- Excavation for Power Canal; and
- Excavation and first stage concrete for powerhouse.

6.3 Year Three

- Construct the powerhouse;
- Complete draft tube, stop logs, hoists & housing;
- Construct the switchyard;
- Construct west causeway and saddle dams;

- Construct the transmission line;

6.4 Year Four

- Completion of powerhouse mechanical and electrical; and
- Final testing and commissioning.

The following works/activities are considered to be on the critical path of the project:

- Environmental and regulatory approvals;
- Detailed design and tending of the water-to-wire ("W2W") package;
- Design, manufacturing and delivery of the W2W equipment; and
- W2W equipment installation and commissioning.

7 Feasibility

Based on the preliminary information there are no anticipated restrictions which would prevent the development of the project. No impact to the existing system is anticipated during construction and any identified environmental concerns can be addressed through the design and implementation of mitigation measures.

The Round Pond Development will be a Run-of-River operation, utilizing regulated flow from the Upper Salmon Development and local Round Pond drainage. Although the net drainage area of the Bay d'Espoir System will not be changed, analysis has shown that the development would result in a net benefit to the system.

Attachment 11

Exploits River Hydroelectric Generation Expansion Report

Exploits River Hydroelectric Generation Expansion

September 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Summary

The study includes the consideration of hydroelectric development alternatives for the Exploits River System including the construction of a 24 MW hydroelectric generating station at Badger Chute and a 42 MW generating station at Red Indian Falls. The total capital cost for Badger Chute is $248.6 million (approximately $10.4 million per megawatt), and the total capital cost for Red Indian Falls is $392.6 million (approximately $9.4 million per megawatt).

The principal parameters for this development are as follows:

	Badger Chute	**Red Indian Falls**
• Installed Capacity	24 MW	42 MW
• Minimum Capacity	1.6 MW	4.2 MW
• Number of Units	3	2
• Estimated Unit Efficiency	85%	85%
• Average Annual Energy	154 GWh	268 GWh

The Red Indian Falls Generating Station would connect to the Island transmission system via a 50 kilometre long, 66 kV transmission line extending from the new generating station switchyard into the existing Buchans Terminal Station. Following its completion, the Badger Chute Development would interconnect via a 20 kilometre transmission line into the Red Indian Falls switchyard,

Operations and Maintenance ("O&M") for the Badger Chute Development is estimated to have a fixed cost of $2.0 M and a variable cost of $0.9 million (approximately $5.70 per MWh) annually. O&M for the Red Indian Falls Development is estimated to have a fixed cost of $3.1 million and a variable cost of $1.5 million (approximately $5.70 per MWh).

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1 Project Description

In 1979, Price (Newfoundland) Pulp and Paper Ltd. commissioned Shawmont Newfoundland Limited to conduct an Exploits River Hydro Inventory. The purpose of the study was to inventory the available hydro power resources on the Exploits River. The study identified the potential for three new hydroelectric developments: Badger Chute, Red Indian Falls, and Four Mile Pond. The general location for these developments is illustrated in Figure 1.

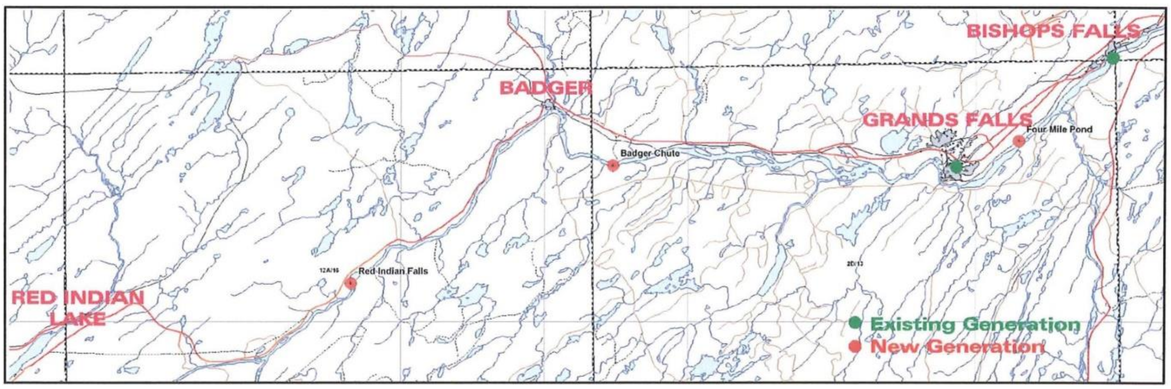

Figure 1: Exploits River New Hydroelectric Development

Each of the developments contemplated would be run-of-river, utilizing the available natural head, and comprised of the following key components:

- Construction of a powerhouse;
- Construction of a concrete gravity dam;
- Construction of a concrete spillway;
- Construction of a fish passage;
- Construction of a switchyard, adjacent to the powerhouse; and
- Construction of a transmission line, connecting the switchyard to the existing System.

1.1 Badger Chute Development

This alternative consists of the construction of a 24 MW hydroelectric generating station on the Exploits River System. Generally speaking, the proposed facility would be located approximately

25 kilometres upstream of Goodyear's Dam and 7 kilometres downstream of the Town of Badger.

The proposed development would be equipped with three vertical Francis turbine generating units and utilize approximately 14.6 metres of natural head for a plant capacity of 24 MW.

1.2 Red Indian Falls Development

This alternative consists of the construction of a, 42 MW hydroelectric generating facility, located approximately 20 kilometres upstream of the Town of Badger.

Generation output would be achieved through the use of two vertical Francis turbines subject to a 22.9 metre head.

1.3 Four Mile Pond Development

The proposed Four Mile Pond Development is situated, approximately 6 kilometres downstream of the existing Exploits Generating Station, in the Town of Grand Falls-Windsor.

There are presently numerous, viable hydroelectric development alternatives available for consideration. As it is believed that this development could negatively impact work completed by the Town of Grand Falls-Windsor to enhance tourism in the region, this option has not been contemplated in the current analysis.

2 Generation Characteristics

Previous analysis of the proposed plants assumed a capacity factor of approximately 85%. No reason is presented for this selection, however, the selection of such a high capacity factor could result in the under sizing of the plant and may not maximize the energy available. Additional firm and average energy may be possible, but would require further investigation and modeling (optimization) of the entire Exploits system.

For the purpose of this report, the principal parameters for the Badger Chute and Red Indian Falls developments are as follows:

2.1 Badger Chute

- Installed Capacity 24 MW
- Minimum Capacity 1.6 MW
- Number of Units 3
- Estimated Unit Efficiency 85%
- Average Annual Energy 154 GWh

2.2 Red Indian Falls

- Installed Capacity 42 MW
- Minimum Capacity 4.2 MW
- Number of Units 2
- Estimated Unit Efficiency 85%
- Average Annual Energy 268 GWh

3 Transmission Requirements

The Red Indian Falls Generating Station would connect to the Island transmission system via a 50 kilometre long, 66 kV transmission line extending from the new generating station switchyard into the existing Buchans Terminal Station. The existing 66 kV bus, at Buchans Terminal Station, will be extended to accommodate the new transmission line.

Following its completion, the Badger Chute Development would interconnect to the System via a 20 kilometre transmission line into the Red Indian Falls switchyard.

4 Environmental Considerations

Hydroelectric developments of this nature will be subject to the Provincial Environmental Protection Act, and the Environmental Assessment Regulations. Given the potential resource conflicts and environmental concerns associated with completing a project of this nature on the Exploits River, an Environmental Preview Report or an Environmental Impact Statement may be required. The project could also be subject to the Federal Environmental Assessment Process. The Federal government in accordance with the Canadian Environmental Assessment Act usually reviews undertakings that are subject to the Provincial Environmental Assessment Process. Where possible the Provincial and Federal Environmental Assessment Process are harmonized in an effective and timely manner.

Through enhancement measures, the Exploits River has become known for its Atlantic salmon run. Originally kept to the lower river because of the falls at Grand Falls and Bishop's Falls, the construction of fish passage systems and fishways combined with stocking have spread the fish throughout the majority of the Exploits' watershed. Therefore, any new developments would be required to satisfy requirements for fish passage both upstream and downstream of the development. Furthermore, flooding of shorelines and tributary streams may also impact fish habitat and fish migration. While measures exist to mitigate and compensate for such impacts, these measures often carry uncertainties related to the degree of success.

Furthermore, the Exploits River provides many socioeconomic benefits for the Province of Newfoundland and Labrador. Recreational boaters, anglers, and the tourism industry would likely be impacted by the completion of such a development.

Similar to the hydroelectric component, transmission line construction would also be subject to an Environmental Assessment. While detailed design has yet to be completed, there are no immediate concerns with respect to the proposed line routing. It is believed that any environmental issues would be typical of any transmission line construction project and could be easily mitigated.

During construction, the control of sedimentation from excavation activities warrants special attention. Controls such as silt fences, rip rap, turbidity curtains, properly constructed settlement basins, containment of run-off from spoil areas, and the relocation of fish during dewatering will need to be implemented. The handling and storage of fuels and other hazardous materials in an environmentally safe manner is also included in the cost.

One of the possible outcomes of the regulatory approval process will be the requirement to develop a detailed Environmental Protection Plan for the Project. An Environmental Protection Plan generally outlines the Owner's policy with respect to environmental protection, the Owner's responsibility, the Contractor's responsibility, compliance monitoring requirements, effects monitoring requirements, and contractor/sub-contractor education, etc.

5 Cost

5.1 Methodology

The cost estimate for the construction of the Badger Chute and Red Indian Falls hydroelectric generation alternatives were originally developed in 1979 as part of an Exploit’s River Hydro Inventory Study*,* completed by Shawmont Newfoundland Limited for Price (Newfoundland) Pulp and Paper Limited.

The Badger Chute alternative was revisited in 2002, by AMEC E&C Services Limited, where it was the subject of a high-level concept review and cost update. This updated estimate then served as a benchmark from which to prorate the original estimate for Red Indian Falls to 2002 dollars. Both estimates were later updated in 2005, by SGE Acres Limited, in review of conceptual layout drawings and preparation of updated cost estimates.

As no additional engineering has since been completed for this option, the current estimates were derived by first escalating the 2005 costs to present day dollars. This was achieved through the application of historical construction price escalation for electric utility construction projects, as measured by Statistics Canada.

Following the completion of the cost escalation exercise, pricing for major components of the project including the powerhouse, generating unit, construction camps and construction support services were compared to current costs, generated for projects of similar size and complexity. Where required, the costs for major components were factored proportionately.

5.2 Capital Cost

A class 5 estimate, for each alternative, was prepared in accordance with the methodology outlined in Section 6.1. These estimates are considered to be adequate for concept screening purposes and carry an expected accuracy range of -20% to +50%.

A summary of the estimates can be seen in Table 1 and Table 2.

Table 1: Badger Chute Development Budget Estimate ($000s)

Project Cost	Year 1	Year 2	Year 3	Year 4	Total
Material Supply	548.4	961.5	1,408.1	344.2	3,262.2
Labour	2,925.0	5,127.9	7,509.7	1,835.7	17,398.3
Consultant	3,656.3	6,409.8	9,387.2	2,294.6	21,747.9
Contract Work	1,410.9	51,278.6	75,097.4	18,357.1	146,144.0
Other Direct Costs	182.8	320.5	469.4	114.7	1,087.4
Interest	197.8	1,502.1	5,635.0	13,734.8	21,069.7
Contingency	0.0	0.0	0.0	37,928.0	37,928.0
Total	**8,921.2**	**65,600.4**	**99,506.7**	**74,609.2**	**248,637.5**

Table 2: Red Indian Falls Development Budget Estimate ($000s)

Project Cost	Year 1	Year 2	Year 3	Year 4	Total
Material Supply	866.1	1,518.3	2,223.5	543.5	5,151.4
Labour	4,619.0	8,097.6	11,858.9	2,898.8	27,474.4
Consultant	5,773.7	10,122.0	14,823.6	3,623.6	34,342.9
Contract Work	2,228.0	80,976.0	118,589.1	28,988.5	230,781.7
Other Direct Costs	288.7	506.1	741.2	181.2	1,717.1
Interest	311.9	2,371.8	8,898.5	21,689.1	33,271.3
Contingency	0.0	0.0	0.0	59,893.5	59,893.5
Total	**14,087.4**	**103,591.8**	**157,134.9**	**117,818.2**	**392,632.3**

This equates to approximately $10.4 million per megawatt and $9.4 million per megawatt for the Badger Chute and Red Indian Falls Developments, respectively.

5.3 Operation & Maintenance Costs

Annual O&M costs for hydroelectric generation plants are typically classified as fixed or variable. Fixed O&M costs relate to those costs incurred during the upkeep and maintenance of the various assets. They typically do not vary significantly with generation and include items such as staffing, plant related general and administrative expenses, and maintenance of structures and grounds.

Variable O&M expenses are production-related costs which vary with the amount of electricity generation. These costs include maintenance of mechanical components such as turbine bearings and runners.

Rule of thumb estimates for the anticipated annual maintenance costs were completed. These estimates were derived from parameters, established through a third party consultant's review of their database for similar works. The parameters utilized for fixed and variable maintenance estimates are as follows:

- Variable O&M: $5.70 per MWh
- Fixed O&M: 1% to 2% of direct project cost per year

Estimated O&M costs are outlined in Table 3.

Table 3: Exploits River Development O&M Costs ($)

	Red Indian Falls	Badger Chute Development
Variable O&M	1,527,600.00	877,800.00
Fixed O&M	3,127,285.15	1,960,502.31
Total O&M	**4,654,885.15**	**2,838,302.31**

6 Schedule

The construction methodology for the Exploits River Developments is typical for heavy civil construction projects, involving various types of earthworks, concrete structures, etc. The original 1979 schedule suggested a 24 to 30month construction period. While this would appear reasonable, construction activity durations are highly dependent upon environmental restrictions. Given the extensive social and environmental considerations, associated with this development, it is prudent to consider a construction period of 48 months.

Also of importance is the fact that the original study failed to identify the anticipated timeframes required for project planning, environmental approvals, permitting, engineering design, and tendering. For the purposes of this exercise one year has been assumed, however, when considering the nature of the development, in combination with the environmental, social and economic factors surrounding a development on the Exploits River, this process could take two to three years to complete.

A summary of the schedule is as follows:

6.1 Year One

- Environmental and Regulatory approval process initiated; and
- Complete additional field testing, studies, etc.

6.2 Year Two

- Engineering/procurement of major equipment;
- Completion of environmental and regulatory approvals;
- Construction of access roads;
- Construction of camp facilities;
- Installation of site services infrastructure;
- Completion of fish passage;
- Completion of dewatering;

- Construction of spillway; and
- Excavate and backfill the powerhouse/switchyard area.

6.3 Year Three

- Construct the powerhouse;
- Complete draft tube, stop logs, hoists & housing;
- Construct the switchyard; and
- Construct the transmission line.

6.4 Year Four

- Completion of powerhouse mechanical and electrical; and
- Final testing and commissioning.

The following works/activities are considered to be on the critical path of the project:

- Environmental and regulatory approvals;
- Detailed design and tending of the water-to-wire ("W2W") package;
- Design, manufacturing and delivery of the W2W equipment;
- Completion of fish habitat mitigation; and
- W2W equipment installation and commissioning.

7 Feasibility

The information available for the Exploits River Hydroelectric Generation Expansion alternatives was developed, primarily for the former mill owners. It is considered to be slightly less than a desk-level screening study and further investigation is required to accurately assess the viability and value of the options. A pre-feasibility study is recommended, complete with a thorough environmental review and hydrology study, to enable an accurate comparison with the other hydroelectric alternatives.

From a scheduling perspective, it is important to note that previous studies indicate that the development of the Badger Chute has the potential to increase ice formation and elevate the risk of flooding for the Town of Badger. It is believed, however, that the construction of Red Indian Falls would, conversely, reduce if not eliminate the flooding problem in the town. For this reason, were the Badger Chute development to be pursued, it should be completed in conjunction with or following the completion of Red Indian Falls.

Based on the available information, both Badger Chute and Red Indian Falls appear to be reasonably viable hydroelectric developments. There are concerns, however, surrounding the degree of accuracy for the current, in-service cost estimates. This, combined with the anticipated sensitivities associated with further hydro developments on the Exploits River raise questions surrounding the viability of these projects and may be significant enough to preclude their development.

In order to properly evaluate the Exploits Generation expansion alternatives, additional study is recommended. A pre-feasibility study which adequately considers the potential environmental constraints and associated mitigation costs is required - the original study placed little emphasis on environmental constraints. Should environmental limitations permit the sanction of the project, it is believed that any mitigation measures, required to address these constraints, could carry a significant cost impact to the projects and their consideration is required to prepare a proper comparison cost estimate.

Attachment 12

Bay d'Espoir Hydro Generating Unit 8 Summary Report

Bay d'Espoir Hydro Generating Unit 8 Summary Report

November 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Summary

The study includes the consideration of the development of a 154 MW unit (Unit 8) located in Powerhouse 2 next to existing Unit 7 at a total capital cost of $393.7 million (approximately $2.6 million per megawatt).

The principal parameters for this development are as follows:

- Time to project in-service   51 months
- Installed Capacity   154 MW
- Number of Units   1
- Estimated Unit Efficiency   98%

The rock excavation for the second unit and downstream portion of the draft tube was constructed in 1977 when Powerhouse 1 was commissioned. As this project would share the existing annual water supply from the existing watershed, there is no direct increased energy production associated with this project.

The Bay d'Espoir Unit 8 would interconnect to the Island transmission system via construction of a 1.9 kilometre, 230 kV line from the Unit 8 step-up transformer to Terminal Station No. 2 ("TS2").

Operations and Maintenance ("O&M") is estimated to have a fixed cost of $1.5 million and a variable cost of approximately $5.70 per MWh annually.

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1 Project Description

Bay d'Espoir Unit 8 is a proposed 154 MW unit located in Powerhouse 2 next to the existing Unit 7. The rock excavation for the second unit and downstream portion of the draft tube was constructed in 1977 when Powerhouse 1 was commissioned.

The Bay d'Espoir facility is comprised of a reservoir including dams and a spillway; two adjacent powerhouses with an average gross head of 179 metres and a total installed capacity of 600 MW; and a tailrace channel rejoining the Bay d'Espoir facility. The addition of Unit 8 would be comprised of the following key components:

- An enlarged headrace channel, including a bifurcation excavated in the rock, supplying both the existing entrance channel to Unit 7 intake and the new entrance channel to Unit 8 intake;
- A new water intake similar to the existing intakes;
- A new buried steel penstock connecting the new intake to the new generating unit;
- A new generating unit; and
- An additional service bay as part of Powerhouse 2 next to existing Unit 7.

The electricity would be produced by the use of a Francis-type turbine, with a rated output of 154 MW.

To complete the interconnection with the existing system, Bay d'Espoir Unit 8 would interconnect to the system via the construction of a 1.9 kilometre, 230 kV line from the Unit 8 step-up transformer to TS2.

2 Generation Characteristics

The principal parameters for this development are as follows:

- Installed Capacity — 154 MW at generator terminals
- Rated Flow — 102 m^3/s
- Gross Head Design — 179.75 m
- Net Design Head — 173.5 m
- Rotating Speed — near 225 rpm
- Estimated Generator Efficiency — 98%

3 Transmission Requirements

Bay d'Espoir Unit 8 would interconnect to the system via construction of a 1.9 kilometre, 230 kV line from the Unit 8 step-up transformer to TS2. The line route would be parallel to the existing line between Unit 7 and TS2 with five transmission line crossings and one river crossing.

4 Environmental Considerations

Hydroelectric developments of this nature will be subject to the Provincial Environmental Protection Act, and the Environmental Assessment Regulations. The overall timeline for the regulatory approval process could be impacted should an Environmental Preview Report or an Environmental Impact Statement be required. The project could also be subject to the Federal Environmental Assessment Process. The Federal government in accordance with the Canadian Environmental Assessment Act usually reviews undertakings that are subject to the Provincial Environmental Assessment Process. Where possible the Provincial and Federal Environmental Assessment Process are harmonized in an effective and timely manner.

The most substantial environmental impact is anticipated to be during the construction phase of the project. However, as the expanded hydropower facility will be integrated to the existing facilities operation with limited changes to the actual operations, less environmental impacts are expected compared to a new hydropower facility.

Similar to the hydroelectric component, transmission line construction would also be subject to Environmental Assessment. While detailed design has yet to be completed, there are no immediate concerns with respect to the proposed line routing. It is believed that any environmental issues would be typical of any transmission line construction project and could be easily mitigated.

During construction, the control of sedimentation from excavation activities warrants special attention. Controls such as silt fences, rip rap, turbidity curtains, properly constructed settlement basins, containment of run-off from spoil areas and the relocation of fish during de-watering will need to be implemented. The handling and storage of fuels and other hazardous materials in an environmentally safe manner is also included in the cost.

One of the possible outcomes of the regulatory approval process will be the requirement to develop a detailed Environmental Protection Plan for the Project. An Environmental Protection Plan generally outlines the Owner's policy with respect to environmental protection, the Owner's responsibility, the Contractor's responsibility, compliance monitoring requirements, effects monitoring requirements, and contractor/sub-contractor education, etc.

5 Cost

5.1 Methodology

The cost estimate for the construction of Bay d'Espoir Unit 8 is an AACE Class 3 estimate, completed by SNC Lavalin in 2017. Typical accuracy ranges for the AACE Class 3 estimates are -10% to -20% on the low side and +10% to +30% on the high side. These accuracy ranges depend on the technological complexity of the project and level of engineering achieved.

All sales taxes have been excluded from the estimate as they are refundable.

5.2 Operation & Maintenance Costs

Annual O&M costs for hydroelectric generation plants are typically classified as fixed or variable. Fixed O&M costs relate to those costs incurred during the upkeep and maintenance of the various assets. They typically do not vary significantly with generation and include items such as staffing, plant related general and administrative expenses, and maintenance of structures and grounds.

Variable O&M expenses are production-related costs which vary with the amount of electricity generation. These costs include maintenance of mechanical components such as turbine bearings and runners.

Rule of thumb estimates for the anticipated annual maintenance costs were completed. These estimates were derived from parameters, established through a third party consultant's review of their database for similar works. The parameters utilized for fixed and variable maintenance estimates are as follows:

- Variable O&M: $5.70 per MWh
- Fixed O&M: 1% to 2% of direct project cost per year

This equates to an estimated annual fixed O&M cost of approximately $1,500,000.00. It is expected that there is no incremental variable O&M cost associated with Unit 8 as the variable cost for the Bay d'Espoir facility is not expected to increase as a result of an additional unit. As mentioned previously, there is no direct increased energy production associated with this project.

6 Schedule

The construction methodology for this project is typical for heavy civil construction projects, involving various types of earthworks, concrete structures, etc. The schedule assumes an overall project duration of 51 months, with construction lasting 41 months. A summary of the schedule is as follows:

6.1 Year One

- Environmental and Regulatory approval process initiated; and
- Complete additional field testing.

6.2 Year Two

- Completion of environmental and regulatory approvals;
- Engineering/procurement of major equipment;
- Upgrade access road to Unit 7;
- Excavate laydown areas;
- Construction of camp facilities;
- Installation of site services infrastructure; and
- Start powerhouse concreting.

6.3 Year Three

- Continued Engineering/Procurement of major equipment;
- Construct the penstock;
- Approach channel excavation;
- Construct the intake;
- Complete construction of powerhouse;
- Powerhouse mechanical and electrical;
- Tailrace excavation; and
- Construct the switchyard;

6.4 Year Four

- Completion of powerhouse mechanical and electrical;
- Install the turbine;
- Trashracks assembly and installation;
- Rock plug excavation; and

- Construct the transmission line.

6.5 Year Five

- Final testing and commissioning; and
- Complete site rehabilitation works.

The following works/activities are considered to be on the critical path of the project:

- Environmental and regulatory approvals;
- Detailed design and tending of the water-to-wire ("W2W") package;
- Design, manufacturing and delivery of the W2W equipment;
- W2W equipment installation and commissioning.

7 Feasibility

Based on the preliminary information there are no anticipated restrictions which would prevent the development of the project. Minimal impact to the existing system is anticipated during construction and any identified environmental concerns can be addressed through the implementation of mitigation measures. However, as construction will be occurring on a brownfield site, no additional environmental issues are expected.

Additionally, Powerhouse 2 was commissioned in 1977 (Phase 3) and the addition of a future unit was considered during construction. As such, rock excavation for the second unit was completed, and the downstream portion of the draft tube, complete with the draft tube gates guides were constructed to minimize interfering with the operation of the existing Unit 7 during the addition of Unit 8.

Attachment 13

Addition of a Third Generating Unit – Cat Arm Report

Addition of a Third Generating Unit

Cat Arm

August 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Summary

The study includes the consideration of the addition of a third, 68.2 MW generating unit at Newfoundland and Labrador Hydro's ("Hydro") Cat Arm Hydroelectric Generating Facility at a total capital costs of $720.5 million (approximately $10.5 million per megawatt).

The principal parameters for this development are as follows:

- Time to project in-service 48 months
- Installed Capacity 68.2 MW
- Minimum Capacity 13.6 MW
- Number of Units 1
- Estimated Unit Efficiency 90%
- Average Annual Energy 25 GWh

The existing Cat Arm Generating Station is connected to the System via a single, 230 kV transmission line TL 247/TL 248 to Deer Lake and Massey Drive. In accordance with current Newfoundland and Labrador System Operator ("NLSO") technical requirements the addition of a third unit will result in a requirement to construct a second 230 kV system interconnection.

Operations and Maintenance ("O&M") is estimated to have a fixed cost of $5.1 million and a variable cost of $0.1 M (approximately $5.70 per MWh) annually.

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1 Project Description

This alternative consists of the installation of a third, 68.2 MW hydroelectric generating unit at Hydro's Cat Arm Generating Station. The unit would be equipped with a Pelton turbine and housed within a newly constructed extension to the south side of the existing powerhouse. The primary mechanical and electrical components for the new generating unit are considered to be identical to Units No. 1 and No. 2.

To maintain access to the transformer yard, at the rear of the existing powerhouse, a permanent access road will need to be constructed, including a bridge across the tailrace.

The supply of water to the new generating unit will be provided by a penstock constructed, primarily, as a free standing pipeline within the high pressure Adit tunnel. It is assumed that the existing tailrace is adequate to handle the overflow of three units, however, flows between the breakwater and beach will need to be surveyed to confirm this assumption.

The addition of the third generating unit will require a second, 230 kV transmission line to complete the interconnection with the existing System. An outline of the transmission requirements can be found in Section 3.

It should be noted that no upgrades have been considered for the following existing system components:

- Existing reservoir system;
- Power canal;
- Forebay tunnel; and
- Forebay canal.

2 Generation Characteristics

For the purposes of this report, the generation characteristics for the new unit are assumed to mimic those of the two existing generation units. With this in mind, the principal parameters for this development are as follows:

- Installed Capacity 68.2 MW
- Minimum Capacity 13.6 MW
- Number of Units 1
- Estimated Unit Efficiency 90%
- Average Annual Energy 25 GWh

3 Transmission Requirements

The existing Cat Arm Generating Station is connected to the System via a single 230 kV transmission line TL 247/TL 248 to Deer Lake and Massey Drive. In accordance with current Newfoundland and Labrador System Operator (“NLSO”) technical requirements the addition of a third unit will result in a requirement to construct a second 230 kV system interconnection. To ensure system reliability, a new indoor gas-insulated switchgear (“GIS”) is required at the Cat Arm Generating Station. The GIS would be configured in a breaker-and-a-half arrangement.

Given the requirement to deliver Cat Arm Unit 3 capacity to the load centre, on the Avalon Peninsula, delivering the capacity to Deer Lake may not be the appropriate point of interconnection for the new transmission line. To this end, a new 230 kV station is proposed near the existing 69 kV Hampden Tap Station. Both TL 247 and the new 230 kV line from Cat Arm would be terminated in this station, configured in a breaker-and-one-half arrangement. The new station would make provisions for additional diameters for future line terminations associated with potential industrial developments. From this point, a new 230 kV line would be constructed eastward to the load centre. Routing of this line would parallel the Labrador Island HVdc routing from the new station location to the HVdc Birchy Lake crossing. Beyond Birchy Lake there are two possible destinations for the new 230 kV line including Buchans Terminal Station and Stony Brook Terminal Station. For this analysis it is proposed that the new 230 kV transmission line run from Kite Pond to Buchans. A line length of 120 kilometres has been assumed.

4 Environmental Considerations

Hydroelectric developments of this nature will be subject to the Provincial Environmental Protection Act, and the Environmental Assessment Regulations. The overall timeline for the regulatory approval process could be impacted should an Environmental Preview Report or an Environmental Impact Statement be required. The project could also be subject to the Federal Environmental Assessment Process. The Federal government in accordance with the Canadian Environmental Assessment Act usually reviews undertakings that are subject to the Provincial Environmental Assessment Process. Where possible the Provincial and Federal Environmental Assessment Process are harmonized in an effective and timely manner.

With respect to the hydroelectric generating station works, negative environmental effects should mainly occur during the construction phase where most effects will be localized, short-term and intermittent. The main benefits of the project should occur during the operation and maintenance phase. Disturbed areas, not required for the operation, will be restored and revegetated. Considering the following, the project should not result in adverse environmental impacts:

- The new hydropower facility will be integrated to the existing facilities operation (brownfield) with limited changes to the actual operations;
- The reservoir level and its management will remain the same; and
- The project is located within a remote area and with the exception of wildlife, is far from the main sensitive receptors;

Similar to the hydroelectric component, transmission line construction would also be subject to Environmental Assessment. While detailed design has yet to be completed, there are no immediate concerns with respect to the proposed line routing. It is believed that any environmental issues would be typical of any transmission line construction project and could be easily mitigated.

During construction, the control of sedimentation from excavation activities warrants special attention. Controls such as silt fences, rip rap, turbidity curtains, properly constructed settlement basins, containment of run-off from spoil areas and the relocation of fish during dewatering will need to be implemented. The handling and storage of fuels and other hazardous materials in an environmentally safe manner is also included in the cost.

One of the possible outcomes of the regulatory approval process will be the requirement to develop a detailed Environmental Protection Plan for the Project. An Environmental Protection Plan generally outlines the Owner's policy with respect to environmental protection, the Owner's responsibility, the Contractor's responsibility, compliance monitoring requirements, effects monitoring requirements, and contractor/subcontractor education, etc.

5 Cost

5.1 Methodology

The original cost estimate, for the addition of Unit No. 3, was originally prepared by Shawmont Newfoundland. This estimate was completed in 1985, immediately following the completion of the original Cat Arm Generating Station project. Given that this estimate was based on the successful completion of the first two units, it is considered to be an accurate estimate for that time.

As no additional engineering has been completed for this option, the current estimate was derived by first escalating the costs to present day dollars. This was achieved through the application of historical construction price escalation for electric utility construction projects as measured by Statistics Canada.

Following the completion of the cost escalation exercise, pricing for major components of the project including the penstock, powerhouse, generating unit, construction camps and construction support services were compared to current costs, generated for projects of similar size and complexity. Where required, the costs were factored proportionately.

Finally, as they were not captured in the original estimate, costs were added for the construction of the new 230 kV transmission line and associated terminal station infrastructure.

5.2 Capital Cost

A class 5 estimate was prepared in accordance with the methodology outlined in Section 5.1. This estimate is considered to be adequate for concept screening purposes and carries an expected accuracy range of -20% to +50%.

A summary of the estimate can be seen in Table 1.

Table 1: Project Budget Estimate ($000s)

Project Cost	Year 1	Year 2	Year 3	Year 4	Total
Material Supply	1,482.4	2,529.5	2,671.3	2,551.2	9,234.4
Labour	7,905.9	13,490.8	14,246.7	13,606.4	49,249.9
Consultant	9,882.4	16,863.5	17,808.4	17,008.0	61,562.3
Contract Work	19,253.5	134,908.0	142,467.1	136,064.1	432,692.7
Other Direct Costs	494.1	843.2	890.4	850.4	3,078.1
Interest	489.9	5,412.4	14,958.9	32,680.3	53,541.5
Contingency	0.0	0.0	0.0	111,163.5	111,163.5
Total	**39,508.3**	**174,047.4**	**193,042.8**	**313,923.9**	**720,522.4**

This equates to approximately $10.5 million per megawatt.

5.3 Operation & Maintenance Costs

Annual O&M costs for hydroelectric generation plants are typically classified as fixed or variable. Fixed O&M costs relate to those costs incurred during the upkeep and maintenance of the various assets. They typically do not vary significantly with generation and include items such as staffing, plant related general and administrative expenses, and maintenance of structures and grounds.

Variable O&M expenses are production-related costs which vary with the amount of electricity generation. These costs include maintenance of mechanical components such as turbine bearings and runners.

Rule of thumb estimates for the anticipated annual maintenance costs were completed. These estimates were derived from parameters, established through a third party consultant's review of their database for similar works. The parameters utilized for fixed and variable maintenance estimates are as follows:

- Variable O&M: $5.70 per MWh
- Fixed O&M: 1% to 2% of direct project cost per year

This equates to an estimated annual variable O&M cost of $142,500.00 and a fixed O&M cost of $5,114,257.32. The magnitude of the fixed O&M cost is attributed to the 120 kilometres transmission system associated with this alternative.

6 Schedule

The construction methodology for this project is typical for heavy civil construction projects, involving various types of earthworks, concrete structures, etc. The schedule assumes an overall project duration of 48 months. A summary of the schedule is as follows:

6.1 Year One

- Environmental and Regulatory approval process initiated;
- Complete additional field testing;

6.2 Year Two

- Engineering/procurement of major equipment;
- Completion of environmental and regulatory approvals;
- Construction of access roads;
- Construction of camp facilities;
- Complete reservoir clearing;
- Construct central/east causeway dams;
- Construction of spillway;
- Excavation for Power Canal; and
- Excavation and first stage concrete for powerhouse.

6.3 Year Three

- Construct the powerhouse;
- Complete draft tube, stop logs, hoists & housing;
- Construct the switchyard;
- Construct west causeway and saddle dams;
- Construct the transmission line;

6.4 Year Four

- Completion of powerhouse mechanical and electrical; and
- Final testing and commissioning.

The following works/activities are considered to be on the critical path of the project:

- Environmental and regulatory approval;
- Detailed design and drawings , and tending of the water-to-wire (“W2W”) package;
- Design, manufacturing and delivery of the W2W equipment; and
- W2W equipment installation and commissioning.

7 Feasibility

Based on the preliminary information there are no anticipated restrictions which would prevent the development of the project.

It should be noted that there may be some operational restrictions, however, as the existing power canal, forebay tunnel, and forebay canal were not designed for simultaneous three unit operation. This may prevent the continuous supply of water, at 60 m^3/s, for three fully loaded units under some low water conditions (i.e., water level. below 387 metres). This should not be a problem for peaking operations where full plant output is limited to a few hours a day.

Impacts on the existing System operation will also be encountered during the construction stage. Units No. 1 and 2 are anticipated will be unavailable while the tunnel is dewatered to facilitate replacement of the bulkhead door, on the upstream end of the existing plug liner, along with the new transition cone. Both the duration and timing of this activity would be critical. A detailed study of the required outage duration has not been completed but it estimated that the tunnel would have to remain dewatered for a period of two to three weeks to complete this replacement. This activity could be done only after the new penstock is in place complete with the spherical valve ready for safe downstream work.

Attachment 14

Gas Turbine Alternatives Report

Gas Turbine Plant Alternatives

November 2018

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

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1 Introduction

Hydro owns and operates four gas turbine plants. These gas turbine plants are:

- Stephenville Gas Turbine Plant (50 MW), located in Stephenville, commissioned in 1975;
- Hardwoods Gas Turbine Plant (50 MW), located in the west end of St. John's, commissioned in 1976;
- Happy Valley Gas Turbine (25 MW) located in Happy Valley-Goose Bay, commissioned in 1992; and
- Holyrood Gas Turbine (123 MW) located at Holyrood Thermal Generating Station ("Holyrood"), commissioned in 2015.

With the exception of the 123 MW gas turbine at the Holyrood, synchronous condensing is the main function of the Hydro's gas turbine plants; however, these gas turbine plants are also operated in generation mode in peak and emergency periods to produce electric power.

Four gas turbine plant alternatives are considered in this study. Three alternatives are based on construction of simple cycle gas turbine plants of various sizes, and the other on the construction of a combined cycle plant.

Considered options have the following capacities:

- Alternative 1: Simple cycle plant, one gas turbine unit rated 66 MW. Total plant capacity 66 MW.
- Alternative 2: Simple cycle plant, two gas turbine units, each rated at 66 MW. Total plant capacity 132 MW.
- Alternative 3: Simple cycle plant, four gas turbine units, each rated at 66 MW. Total plant capacity 264 MW.
- Alternative 4: Combined cycle plant, two gas turbine units, each rated at 66 MW and steam turbine rated at 38 MW. Total plant capacity 170 MW.

The gas turbine plants will be used primarily for peaking duty but also have fuel storage capacity to run continuously for at least five days. They will also have synchronous condensing capability.

1.1 Scope of Work

1.1.1 Part A: Gas Turbine Plant

The scope of work includes, but is not limited to, the following:

- An aeroderivative gas turbine package(s) with a capability of fast start (generation up to rated load in not more than ten minutes). A package generally consists of a gas turbine engine, power turbine, generator, air inlet filtration unit, exhaust stack, start-up system, instrumentation and control system.
- Instrumentation and control systems for the balance of the plant ("BoP").
- Electrical systems including high voltage system (230 kV System), low voltage systems (480 V and 120/208 V systems), generator step-up ("GSU") transformer, batteries/chargers/uninterruptible power supply ("UPS") systems , lighting poles/panels, plant ground grid , lightning protection on the exhaust stacks, cathodic protection for outside tanks and underground metallic piping systems, and cabling/wiring.
- Buildings including powerhouse for the gas turbine package(s) and BOP, control room, and administration office.
- Civil work including site preparation, excavation, concrete foundations, overhead crane, and structural steel such as racks, supports, ladders, and platforms.
- Auxiliary systems such as inlet/heating de-icing system, lube oil system, liquid fuel system (including five days of fuel storage), raw water, water treatment, demineralized water, compressed air system, oily water drain system, black start, and fire protection.
- Water supply line to the site.
- Land purchase for the installation, as required.

1.1.2 Part B: Interconnection

The scope of work includes, but is not limited to, the following:

- New terminal station for all alternatives except Alternative 5 as it was assumed this alternative will replace one the two generating Units 1 or 2 at Holyrood.
- Transmission lines to the site and interconnection as required.

2 Technical

2.1 Rated Capacity and Location

Table 1 provides the proposed location and rated capacity at ISO conditions (ambient temp 15°C, ambient relative humidity 60% and ambient pressure 1.013 bar) for the gas turbine plant for each alternative.

Table 1: Rated Capacity of Gas Turbine Plant

Alternative	Rated Capacity
1	Simple cycle gas turbine plant, one unit, each rated 66 MW
2	Simple cycle gas turbine plant, two units, each rated at 66 MW
3	Simple cycle gas turbine plant, four units, each rated at 66 MW
4	Combined cycle gas turbine plant, rated at 170 MW

2.2 Performance Data

The gas turbine performance data is different based on the installed gas turbine package(s) efficiency and operation cycle configuration (simple or combined cycle). For example, Table 2 provides performance data for each gas turbine plant alternative based on Siemens SGT-A65 (Trent 60) aeroderivative gas turbine package(s).

Table 2: Performance Data for Siemens SGT-A65 Gas Turbine

	Alt. 1	Alt. 2	Alt. 3	Alt. 5
Maximum Capacity (MW)	66	132	264	170
Minimum Capacity (MW)	33	33	33	81.6
Heat Rate @ Max Capacity (GJ/MWh)	8,813	8,813	8,813	7,264
Heat Rate @ Min Capacity (GJ/MWh)	10,460	10,460	10,460	7,310
Planned Maintenance Rate (days/year)	17.2	17.2	17.2	17.2

2.3 Environmental Requirements

The following environmental requirements have been considered:

1) The gas turbine shall comply with best available control technology. This is a regulatory requirement and covered off by the emissions control.
2) A source of water must be available and a water use license is required. Water could be supplied from the city or an intake on the closest pond to the site shall be installed which will require a permit.
3) The gas turbine shall be subject to an environmental assessment. Main concerns would be emissions, fuel and noise. The physical location of the plant and the impact of traffic related to fuel delivery shall be taken into consideration.
4) The fuel will be stored in vertical tanks. This would be subject to GAP requirements such as registration and testing.

3 Capital Cost Estimate (Class 5)

3.1 Methodology

Each cost estimate was prepared based on the supply and installation a gas turbine plant by an Engineering, Procurement, Construction, and Management ("EPCM") contractor according to the scope of work provided in Section 1.1.1 of this report. The scope of work for the interconnection as provided in Section 1.1.2 of this report will be completed by external contractors and Hydro internal construction labour. Budgetary quotes were obtained from gas turbine suppliers (Siemens, GE, and PW) and from gas turbine engineering, procurement, and construction ("EPC") contracts (ProEnergy and Aecon Industrial East). Internal labour costs (engineering and construction) were estimated based on the actual labour costs for the 2015 Holyrood Gas Turbine plant with an adjustment of the cost to account for the capacity for each gas turbine alternative compared to the capacity for Holyrood Gas Turbine.

A contingency of 20% and interest of 3% per year were added to the total cost to estimate the budget. No escalation was added to the cost estimate as the modeling that Hydro completed to compare the alternatives already includes the escalation.

3.2 Cost Estimate

The estimated cost can be classified as Class 5 with an expected accuracy range of -20% to +40%. The Association for the Advancement of Cost Engineering ("AACE") International Recommended Practice ("RP") provides guidelines for the cost estimate classification. According to the AACE RP, the cost estimate can be classified as Class 5 when the maturity level of project definition is 0-2%. The Class 5 cost estimate is usually used for concept screening. The maturity level of project definition is based on the status of specific key planning and design deliverables. While the determination of the maturity level of project definition, and hence the estimate class, is somewhat subjective, we believe that the level of project definition for the addressed gas turbine alternatives in this report is in the range of 1-15% which is qualified to be Class 4 as per the AACE RP.

Table 3 provides the capital cost estimate for each alternative including the gas turbine plant and interconnection.

Table 3: Capital Budget Estimate (2018 CDN$)

Item	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Material Supply	1,275,721	7,135,268	33,539,750	1,759,750
Labour	3,706,111	4,247,602	18,066,497	4,917,017
Consultant	2,147,753	2,115,753	3,792,752	3,103,253
Contract Work	126,859,783	222,408,423	458,765,707	419,216,000
Other Direct Costs	202,000	290,000	1,050,000	355,000
Interest	8,027,482	14,171,823	46,369,324	38,641,592
Contingency	26,758,274	47,239,409	103,042,941	85,870,204
Capital Budget	168,977,124	297,608,278	664,626,971	553,862,816
Land Price	3,600,000	7,200,000	13,200,000	___

3.3 Annual Cost Breakdown

Table 4 provides the annual cost breakdown for each alternative.

Table 4: Annual Cost Breakdown

	Alt. 1	Alt. 2	Alt. 3	Alt. 4
Capital Budget (CDN$)	168,977,124	297,608,278	664,626,971	553,862,816
% Cost (Year 1)	35	35	30	30
% Cost (Year 2)	65	65	45	45
% Cost (Year 3)	0	0	25	25

4 Operating and Maintenance Costs

The O&M costs for each alternative were estimated assuming the gas turbine is aeroderivative and operated according to the following two cases:

1) Peaking load assuming operation for 500 hours per year and maximum 120 starts per year.
2) Baseload assuming continuous operation (8,333 hours per year).

The fixed O&M costs are expenses that do not vary significantly with electrical generation such as staffing and routine maintenance that does not require an extended plant shutdown. The fixed O&M costs are incurred even if the plant is offline (standby). The staffing cost was based on two operators per gas turbine unit (three shifts per day) for all alternatives and one operator (three shifts per day) for the steam turbine in the combined cycle gas turbine (Alternative 5). For example, Alternative 4 which includes four gas turbine units will require eight operators (three shifts per day).

The variable O&M costs are production-related costs which vary significantly with electrical generation. It includes inspections and overhauls as scheduled by the original equipment manufacturer.

The start cost is the impact of each planned start or due to a trip of the gas turbine on the scheduled inspections and overhauls.

The O&M costs do not include electricity, fuel-related costs, and consumable materials such as chemicals and lubricants.

Table 5 provides the O&M costs for each alternative.

Table 5: Operating and Maintenance Costs

Item	Unit	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Notes
Variable O&M	$/MWh	10.6	8.5	7.1	7.1	Peaking load (500 hrs/year)
		5.3	4.3	3.6	3.4	Baseload (8,333 hrs/year)
Fixed O&M	$/kW-year	10.3	10.3	10.3	10	
Start Cost	$/start	0	0	0	0	Maximum 120 starts/year

The estimated O&M costs in Table 5 were compared by a consultant (Daymark) to available industry-wide O&M cost estimates including EIA (Capital Cost Estimates for Utility Scale Electricity Generating Plants), National Renewable Energy Laboratory (Cost and Performance Data for Power Generation Technologies), Lazard's (Levelized Cost of Energy Analysis), and Western Electric Coordinating Council (Capital Cost Review of Power Generation Technologies). The estimated O&M costs, as provided in Table 5, fall in line within available industry-wide O&M cost estimates for electricity generating plants.

Attachment 15

Full Results of Resource Planning Cases

Island Interconnected System High Growth Case						
Year	P50 Forecast			P90 Forecast		
	Labrador Base	Labrador High Industrial Growth	All Recapture Consumed in Labrador	Labrador Base	Labrador High Industrial Growth	All Recapture Consumed in Labrador
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-
2021	-	-	-	-	-	-
2022	-	-	-	-	-	132 MW GT
2023	-	-	-	-	-	-
2024	-	-	-	-	-	-
2025	-	-	-	-	132 MW GT	-
2026	-	-	66 MW GT	-	-	-
2027	-	-	-	66 MW GT	-	-
2028	-	66 MW GT	-	-	-	66 MW GT

Island Interconnected System Low-Rate Case						
Year	P50 Forecast			P90 Forecast		
	Labrador Base	Labrador High Industrial Growth	All Recapture Consumed in Labrador	Labrador Base	Labrador High Industrial Growth	All Recapture Consumed in Labrador
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-
2021	-	-	-	-	-	-
2022	-	-	-	-	-	-
2023	-	-	-	-	-	132 MW GT
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	-	-	-	-	66 MW GT	-

Island Interconnected System Mid-Rate Case						
Year	P50 Forecast			P90 Forecast		
	Labrador Base	Labrador High Industrial Growth	All Recapture Consumed in Labrador	Labrador Base	Labrador High Industrial Growth	All Recapture Consumed in Labrador
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-
2021	-	-	-	-	-	-
2022	-	-	-	-	-	-
2023	-	-	-	-	-	-
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	-	-	-	-	-	-

Island Interconnected System High Rate Case						
Year	P50 Forecast			P90 Forecast		
	Labrador Base	Labrador High Industrial Growth	All Recapture Consumed in Labrador	Labrador Base	Labrador High Industrial Growth	All Recapture Consumed in Labrador
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-
2021	-	-	-	-	-	-
2022	-	-	-	-	-	-
2023	-	-	-	-	-	-
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	-	-	-	-	-	-

Abbreviations

CCCT	Combined-Cycle Combustion Turbine
CDM	Conservation and Demand Management
CEA	Canadian Electricity Association
CPP	Critical Peak Pricing
DAFOR	Derated Adjusted Forced Outage Rate
DAUFOP	Derated Adjusted Utilization Forced Outage Probability
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
GDP	Gross Domestic Product
GT	Gas Turbine
Holyrood	Holyrood Thermal Generating Station
IIS	Island Interconnected System
LIL	Labrador-Island Link
LIS	Labrador Interconnected System
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LTA	Labrador Transmission Assets
ML	Maritime Link
NERC	North American Electric Reliability Corporation
Hydro	Newfoundland and Labrador Hydro
NLIS	Newfoundland and Labrador Interconnected System
NLSO	Newfoundland and Labrador System Operator
NPCC	Northeast Power Coordinating Council, Inc.
O&M	Operating and Maintenance
PPA	Power Purchase Agreement
UFLS	Underfrequency Load Shedding
UFOP	Utilization Forced Outage Probability

Definitions

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers within the system criteria, taking into account scheduled and unscheduled outages of system elements.[1]

Adjusted Gross Domestic Product: Excludes income that will be earned by the non-resident owners of provincial resource developments to better reflect growth in economic activity that generates income for local residents.

Base Case: The base case is the expected case, determined by using the assumptions considered most likely to occur.

Capacity Assistance: Contracted curtailable loads and customer generation that can be called on for system support. Capacity assistance agreements are generally restricted in terms of frequency, duration and annual usage.

Coincidence Factor: The coincidence factor is a measure of the likelihood of the independent systems peaking at the same time. For the Newfoundland and Labrador Interconnected System ("NLIS"), it provides a measure of the relative contribution of the Island Interconnected System ("IIS") and the Labrador Interconnected System ("LIS") peaks to the combined NLIS Peak.

Consumer Price Index: The consumer price index is an indicator of the change in consumer prices. It measures price change by comparing through time the cost of a fixed-basket of consumer goods and services.[2]

Critical Peak Pricing: Critical peak pricing offers customers time-varying rates that reflect the cost of capacity during critical peak times. By significantly increasing the rate during that time, customers are incented to significantly shift or reduce demand during the critical peak period.

Curtailable Load: A load, typically commercial or industrial that can be interrupted at the request of the system operator.

Demand: (1) The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. (2) The rate at which energy is being used by the customer.[3]

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[1] "Reliability Assessment Guidebook," NERC, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>

[2] Statistics Canada, "Chapter 1 – Introduction to the Canadian Consumer Price Index," November 30, 2015. <https://www150.statcan.gc.ca/n1/pub/62-553-x/2014001/chap/chap-1-eng.htm>

[3] "Reliability Assessment Guidebook," NERC, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>

Demand-Side Management (also known as Customer Demand Management): The term for all activities or programs undertaken by the utility and/or its customers to influence the amount or timing of electricity they use.[4]

Derated Adjusted Forced Outage Rate ("DAFOR"): Measures the percentage of time that a unit or group of units is unable to generate at its Maximum Continuous Rating ("MCR") due to forced outages.

Derated Adjusted Utilization Forced Outage Probability ("DAUFOP"): The probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate.

Deterministic Analysis: Uses a set of known and fixed system conditions and probabilities (load, forced outage rates, transmission flows, and intermittent generation) to determine system reliability. Deterministic analysis is computationally efficient but does not consider many of the uncertainties present in real-world systems.

Dispatchable Resource: A dispatchable resource is a generation resource that can be used on demand and increased or decreased at the request of operators, according to system needs.

Effective Load Carrying Capability ("ELCC"): A metric used to assess firm capacity credit for intermittent generation resources. It is a measure of the additional load that the system can supply with the addition of a generator with no net change in reliability.

Electrical Power Control Act, 1994 ("EPCA"): The Act which regulates the electrical power resources of Newfoundland and Labrador.[5]

Emergency Operating Procedure ("EOP"): A procedure that includes a number of possible mitigating actions that can be enacted by the system operator, as required, to provide system relief.

Expected Unserved Energy ("EUE"): A measure of the amount of customer demand not served due to generation shortfalls.

Firm Capacity: the amount of generation capacity available for production or transmission guaranteed to be available when the unit is operational.

[4] "Reliability Assessment Guidebook," NERC, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>

[5] *Electrical Power Control Act, 1994* Chapter E-5.1. <https://www.assembly.nl.ca/legislation/sr/statutes/e05-1.htm>

Firm Demand: That portion of the demand that a power supplier is obligated to provide, except when system reliability is threatened or during emergency conditions.[6]

Firm Energy: Firm energy refers to the actual energy guaranteed to be available to meet customer requirements.

Firm Imports and Exports: A contract for the import or export of capacity or energy guaranteed to be available at a given time.

Forced Outage: (1) The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. (2) The condition in which the equipment is unavailable due to unanticipated failure.[7]

Forced Outage Rate ("FOR"): The expected level of unavailability of a unit due to unforeseen circumstances.

Gross Domestic Product ("GDP"): GDP is the total unduplicated value of the goods and services produced in the economic territory of a country or region during a given period.[8]

Island Interconnected System ("IIS"): The interconnected portion of the island's electrical system. It is characterized by large hydroelectric generation capability located off the Avalon Peninsula, the Holyrood Thermal Generating Station on the Avalon Peninsula, and the bulk 230 kV transmission system extending from Stephenville in the west to St. John's in the east. The IIS is interconnected to the LIS via the Labrador-island Link ("LIL"). The IIS is also connected to the North American grid via the Maritime Link ("ML").

Labrador Interconnected System ("LIS"): The interconnected portions of Labrador's electrical system form the LIS. It is characterized by supply at Churchill Falls (provided by TwinCo Block and Recapture Energy), radial transmission to the two major load centres in Labrador East and Labrador West, and the Labrador Transmission Assets ("LTA") connecting Churchill Falls to Muskrat Falls. The LIS is connected to the IIS via the LIL. The LIS is also connected to the North American grid via the 735 kV ac transmission lines from Churchill Falls to Quebec.

Labrador Island Link ("LIL"): A 900 MW high voltage dc transmission line designed to deliver power from the Muskrat Falls Generating Station to Soldiers Pond Terminal Station on the Avalon Peninsula.

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[6] "Reliability Assessment Guidebook," NERC, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>
[7] Ibid.
[8] Statistics Canada, "Gross Domestic Product (GDP).", September 20, 2017 <https://www.statcan.gc.ca/eng/nea/list/gdp>

Load Forecast: The projected energy and demand requirements for the electrical system. The load forecast process entails translating a long-term economic and energy price forecast for the Province into corresponding electric demand and energy requirements for the electric power systems. Hydro predicts future load requirements for the Island Interconnected System primarily through econometric modelling techniques and large industrial customer input. Future load requirements for the Labrador Interconnected system are primarily through historical trend analysis and large industrial customer input.

Load Forecast Uncertainty: A multiplier representing the potential variance in annual peak demands. Its development is based on a distribution of expected values of load based upon an analysis of the weather sensitivity of peak loads.

Loss of Load Expectation ("LOLE"): The expected number of days each year where available generation capacity is insufficient to serve the daily peak demand.

Loss of Load Hours ("LOLH"): Loss of Load Hours is the expected number of hours per year when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated using each hourly load in the given period instead of using only the daily peak in the LOLE calculation.

Loss of Load Probability ("LOLP"): The probability of system daily peak or hourly demand exceeding available generating capability in a given study period.

Maritime Link ("ML"): A high voltage dc transmission line connecting Newfoundland and Nova Scotia.

Maximum Continuous Rating ("MCR"): The maximum continuous rating is defined as the maximum output in MW that a generating station is capable of producing continuously under normal operating conditions over a year.

Monte Carlo Simulation: A mathematical technique that generates random variables for modelling risk or uncertainty of a certain system.

Newfoundland and Labrador Interconnected System ("NLIS"): The Island Interconnected System ("IIS") and the Labrador Interconnected System ("LIS") combine to form the NLIS.

North American Electric Reliability Corporation ("NERC"): A non-profit, self-regulating organization whose objective is to ensure adequate reliability of the bulk power system in North America.

Northeast Power Coordinating Council, Inc. ("NPCC"): NPCC is a regional entity division which operates under a delegation agreement with the North American Electric Reliability Corporation (NERC). Members include the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec, and the Maritime provinces of New Brunswick and Nova Scotia.

Nova Scotia Block: A firm commitment of 980 GWh, to be supplied annually from the Muskrat Falls Generating Station on peak.

Non-Dispatchable Resource: A non-dispatchable resource is an energy resource, such as wind power, that can not be used on demand and dispatched as per system needs.

Non-Firm Imports and Exports: A contract for the import or export of capacity or energy which is not guaranteed to be available at a given time.

Non-Spinning Reserve: (1) That generating reserve not connected to the system but capable of serving demand within a specified time. (2) Interruptible load that can be removed from the system in a specified time.[9]

Normalized Expected Unserved Energy: A measure of the amount of customer demand not served due to generation shortfalls divided by the total system energy.

Operational Reserve: A system requirement where the system requires the ability to withstand the loss of the single largest resource while maintaining an additional reserve.

Peak Demand: The highest hourly demand on a system occurring within a year.[10]

Planning Reserve Margin: The reserve margin at which the system reliability is at criteria. It is used as a reliability metric to evaluate the system's resource adequacy for expansion planning.

Probabilistic Analysis: Probabilistic analysis simulation requires completion of several simulations using randomly sampled variables like outage profiles, wind generation and weather related load uncertainty to determine system reliability. When compared to deterministic analysis, probabilistic analysis better incorporates the random behavior of system states as well as the operational restrictions of the system. See Monte Carlo Analysis.

Power Purchase Agreement ("PPA"): A contract for the purchase of capacity and/or energy from a third party.

P50 Forecast: A P50 forecast is one in which the actual peak demand is expected to be below the forecast number 50 percent of the time and above 50 percent of the time (i.e.. the average forecast.)

[9] "Reliability Assessment Guidebook," NERC, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>
[10] Ibid.

P90 Forecast: A P90 forecast is one in which the actual peak demand is expected to be below the forecast number 90 percent of the time and above 10 percent of the time (i.e., there is a 10 percent chance of the actual peak demand exceeding the forecast peak demand.)

Reserve Margin: The amount by which available firm capacity exceeds capacity required to meet peak demand.

Run-of-River: Hydroelectric generating facilities with limited storage capability, where production is dictated by the water available in the river at the time of generation.

Sensitivities: Cases developed to study the impact of change in variables on resource planning analysis. These sensitivities include addition of large loads in Labrador, and the uncertainty in load projections associated with future customer rates.

Spinning Reserve: Unloaded generation that is synchronized and ready to serve additional demand.[11] Also referred to as synchronized reserve.

Supplemental Energy: A firm energy commitment to supply energy to Nova Scotia during the first five years of production at the Muskrat Falls Generating Station as part of the Amended and Restated Energy and Capacity Agreement.

Synchronized Reserve: Refer to Spinning Reserve.

System Operator: Entity entrusted with the operation of the control center and the responsibility to monitor and control the electric system in real time.[12]

Time-of-use-Rates: An option for customers that offers electricity rates that vary throughout the day based on load patterns; with the highest rates during peak hours and lowest rates during off-peak hours.

Transmission Constraint: A limitation on one or more transmission elements that may be reached during normal or contingency system operations.[13]

Underfrequency Load Shedding ("UFLS"): the automatic or manual actions required to shed system load when the system frequency falls below defined acceptable parameters.

Utilization Forced Outage Probability ("UFOP"): is the probability that a generating unit will not be available due to forced outages when there is demand on the unit to generate.

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[11] "Reliability Assessment Guidebook," NERC, March 2008, Version 1.2 <https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%20DL/Reliability%20Assessment%20Guidebook/Reliability_Assessment_%20Guidebook%20v1.2%20031909.pdf>
[12] Ibid.
[13] Ibid.